Illinois Environmental Protection Agency
Bureau of Air
Permit Section

April 2012

Responsiveness Summary for Public Questions and Comments on the Construction Permit Application from Christian County Generation for the Taylorville Energy Center in Taylorville, Illinois

Source Identification No.: 021060ACB
Application No.: 05040027

Table of Contents

DECISION

On April 30, 2012, the Illinois Environmental Protection Agency (IEPA) issued an air pollution control construction permit to Christian County Generation, LLC, for its proposed coal gasification plant. The comments that were submitted during the comment period were helpful to the IEPA in the decision making process.

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 IEPA website www.epa.state.il.us/public-notices/.

BACKGROUND

On April 8, 2010, the IEPA, Bureau of Air received an application from Christian County Generation, LLC, requesting a permit to construct a coal gasification plant. The proposed plant would produce substitute natural gas (also known as synthetic natural gas) and generate electricity for the grid. The plant would have two gasifiers with an associated gasification cleanup train, a sulfur recovery plant, two combustion turbines, and various ancillary and support operations. The plant would be located in Taylorville, Illinois.

The proposed plant would be known as the Taylorville Energy Center (TEC). The permit application for the plant was submitted by Christian County Generation, LLC (CCG).

The construction permit issued for the project 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 emissions testing, continuous emission monitoring, recordkeeping, and reporting. Christian County Generation will be required to carry out these procedures on an ongoing basis to demonstrate that the plant is operating within the limitations established by the permit and that emissions are being properly controlled.

COMMENT PERIOD AND PUBLIC HEARING

The IEPA 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 Christian County Generation's application, the IEPA Bureau of Air made a preliminary determination that the application met the standards for issuance of a construction permit and prepared a draft permit for public review and comment.

The public comment period began with the publication of a notice in the Springfield State Journal Register and the Taylorville Breeze Courier on October 17, 2011. The notice was published again in both newspapers on October 24 and 31, 2011.

A public hearing was held on December 1, 2011, at the Taylorville Junior High School to receive oral comments and answer questions regarding the application and draft air permit. The comment period closed on December 31, 2011.

AVAILABILITY OF DOCUMENTS

The permit issued to Christian County Generation 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), PSD/Major NSR Records). Copies of these documents may also be obtained by contacting the IEPA at the telephone numbers listed at the end of this document.

APPEAL PROVISIONS

The permit being issued for the proposed project grants approval to construct pursuant to the federal rules for Prevention of Significant Deterioration of Air Quality (PSD), 40 CFR 52.21. Accordingly, individuals who filed comments on the draft permit or participated in the public hearing may petition the US Environmental Protection Agency (USEPA) to review the PSD provisions of the issued permit. In addition, as comments were submitted on the draft permit for the proposed project that requested a change in the draft permit, the issued permit does not become effective until after the period for filing of an appeal has passed. The procedures governing appeals are contained in the Code of Federal Regulations (CFR), "Appeal of RCRA, UIC and PSD permits," 40 CFR 124.19. If an appeal request will be submitted to USEPA by a means other than regular mail, refer to the Environmental Appeals Board website at www.epa.gov/eab/eabfaq.htm#3 for instructions. If an appeal request will be filed by regular mail, it should be sent on a timely basis to the following address:

U.S. Environmental Protection Agency
Clerk of the Board, Environmental Appeals Board (MC 1103B)
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460-0001
Telephone: 202/233-0122

COMMENTS AND QUESTIONS AND WITH RESPONSES BY THE IEPA

I. COMMON PUBLIC CONCERNS

The proposal to issue a permit for the construction of the Taylorville Energy Center (TEC) has generated a variety of comments from the public and environmental organizations. The comments that were submitted were helpful to the IEPA in the decision making process and these comments were fully considered by the IEPA prior to issuance of the permit on April 26, 2012. Common concerns raised during the comment period are discussed in this section of the Responsiveness Summary. Individual comments and detailed responses follow in subsequent sections.

A major concern raised during the comment period was whether emissions of the plant will be a threat to ambient air quality and public health in Christian County. As part of the application, Christian County Generation was required to submit a modeling analysis to determine the impact of the Taylorville Energy Center (TEC) on local ambient air quality. The modeling and subsequent analysis indicate air quality would continue to comply with the National Ambient Air Quality Standards, which have been developed by USEPA to protect public and welfare.

A related concern was how the IEPA would take into account other sources of emissions in the area and background levels of air quality when evaluating the plant. The ambient air quality analysis looks at other sources of emissions and background levels of pollutants when the analysis indicates that emissions from the plant would be above a very small or "de minimis" level of impact. A preliminary analysis for the plant by itself indicated potential impacts above these levels. This triggered further analysis with modeling of both the emissions of the proposed plant and the emissions of existing sources in the area. This full modeling analysis, which took into account other sources and background air quality, showed that the plant would not threaten current air quality.

Comments were also received about whether the permit requires stringent controls on the emissions from the plant. The permit requires the plant to use Best Available Control Technology (BACT) to control its emissions, as determined on a project-specific basis. As part of its application, Christian County Generation was required to review the control techniques that are available and the emission limits that would be achievable with these techniques considering other similar facilities that already use them, to identify the most stringent control techniques. The most stringent level of control is selected as BACT unless that is shown to be technically infeasible or accompanied by cost or environmental impacts that would be excessive.. The IEPA reviewed the BACT analysis that was submitted to actually determine BACT requirements for the plant and set appropriate condition in the permit requiring use of BACT.

The plant would not be a major source for emissions of hazardous air pollutants. The permit sets stringent limits on emissions of mercury for a plant of its size. The issued permit limits emissions of mercury to 20 pounds per year, a 90 percent decrease from the level proposed in the draft permit and a fraction of the mercury levels of existing coal fired power plants. With respect to mercury pollution, emissions of mercury pose an indirect threat to public health due to the bioaccumulation of mercury in fish. Individuals who eat fish caught in Illinois should be aware of the Fish Advisories issued by the Illinois Department of Public Health. These advisories provide recommendations for the amount of different species of fish from various lakes and rivers in Illinois that should be consumed by women of childbearing age, children, and other classes of people.

The plant is being developed with the expectation that it would be able to use Carbon Capture and Sequestration (CCS) to reduce its emissions of carbon dioxide (CO_2). The plant would be developed to be a "clean coal facility" under the Illinois Clean Coal Portfolio Standard Law, which would require geological sequestration of CO_2. However, the permit does not require sequestration because this innovative technology is not yet adequately demonstrated so as to be able to definitively determine that it would be technically feasible when the plant begins operation and during its entire operating life (i.e., as BACT). However, one of the benefits of the plant should be to demonstrate the technical feasibility and reliability of CO_2 sequestration.

Comments were also made about the various impacts of coal mining and processing that accompany the use of coal to produce electricity. While the IEPA regulates emissions and water discharges from coal mining and processing, the primary responsibility for regulating mining lies with the Department of Mines and Minerals in Illinois' Department of Natural Resources.

Finally, comments were made that alternative forms of power generation are needed. As reported by the media, wind power has developed in Illinois over the last few years, with companies that are interested in developing wind power projects pursuing projects in the areas where conditions are suitable for such projects. The IEPA recognizes the clear environmental benefits as it has zero emissions. However, wind energy cannot eliminate the need for fossil-fuel-based plants, like the proposed plant. As the strength of the wind varies, so does the power output from a wind turbine. On an annual basis, the output of wind turbines in Illinois is only a fraction of their design capacity. Fuel-based plants, whose output is not dependent on the weather, are essential for a reliable supply of power.

II. GENERAL COMMENTS

The IEPA received numerous general comments and comments that do not address environmental issues or regulations. Representative examples of these comments are listed below without response.

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, we also understand the need for clean fuel, clean utilities, and higher emitting facilities that will replace those that are causing more pollution. This project has been well-considered and well-received in the area, and we 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. Taylorville Energy will provide these jobs. Not just construction jobs, but mining jobs, jobs in transportation, real estate, restaurants, and all segments of our economy were in central Illinois. Taylorville 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 hope for Taylorville and the surrounding county, hope for a new industry and a revival of our economy, hope for a brighter future for our children. It also represents the possibility of a more secure and

affordable energy future for our state. We truly believe that the Taylorville Energy Center will be a catalyst for growth not only within the city but in the surrounding area as well.

I feel confident that this plant will be built and operated within all the health- based federal and state environmental standards. No one is more concerned about those issues than we are here locally. After all, it's our community, our environment that's being impacted, and our quality of life that I believe will be bettered. My confidence is based on the fact that I know the developers of the project, and they have proven to be conscientious neighbors in the places where they currently have other facilities.

The Christian County Economic Development Corporation supports this project for several reasons. First, the project will help replace some of the jobs that have been lost. The economic impact on our city, county, and state will be very significant and very substantial. Second, the project, in our view, is an environmentally responsible project. Finally, this project will empower Illinois to become more self-sufficient, more self-reliant, and more environmentally responsible regarding its capacity for energy production.

The economic benefits of the project are very clear and the project is paramount to the future of all Christian County and central Illinois. Based on my longtime involvement with this project, I'm confident that Tenaska has an intense emotion of operating their plant according to federal, state, and industry guidelines to be a shining star, a worldwide example of clean coal technology, a plant that has many emission profiles of a natural gas plant.

This plant would be the first step in merging our enormous supply of coal with a clean coal technology to use it to create a market for Illinois coal, coal use in Illinois. This is an opportunity to replace the aging Illinois power plants burning Wyoming coal with clean coal technology using Illinois coal. Coal gasification means an expansion of good-paying and coal mining jobs in Illinois.

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

This company is seeking mandatory 30-year contracts, which means 20 and 30 years from now when Illinois will have a great deal of cheaper and cleaner power online, Illinois will still be required to buy overpriced dirty energy from this plant regardless of the cost.

The plant would cost taxpayers millions of dollars annually, in state and federal subsidies. It would also eliminate thousands of jobs in Illinois per year as a result of higher utility rates and their impact on commerce and small businesses. These ratepayers would be responsible for a portion of cost overruns, which will likely be substantial.

The plant will significantly increase emissions of CO_2, a greenhouse gas.

At this year for the first time, the University of Illinois did not utilize coal over the summer.

This is an important step and represents leadership from the University of Illinois. This is the same sort of leadership that Illinois government should be showing.

Illinois needs to use more renewable energy. Renewable energy can and does produce jobs. Renewable energy produces cheaper energy. That is why companies like ADM are opposed to this plant. And renewable energy does not harm the environment.

By avoiding emissions of mercury from burning coal, we can avoid toxic impacts on our environment, on our streams and wildlife. This is not clean coal and there should not be any mistake about it.

III. GENERAL QUESTIONS WITH IEPA RESPONSES

1. What type of coal was used for the design of the plant? Were other feedstocks considered?

The plans for the plant and the emission data in the application are based on the use of high-sulfur, Illinois Basin coal. This is the type of coal that is commonly present in Illinois and that is generally mined. This is also the type of coal that must be used for the plant to qualify as a clean coal facility under the Clean Coal Portfolio Standard Law. The potential for using other coals and alternative feedstocks was considered as part of the review of Best Available Control Technology (BACT) for the plant, as discussed later in this document.

2. I am very concerned about flaring. Is there any limit as far as the amount of flaring that can be done within a certain amount of time, for example, a 24-hour period.

While flaring is commonly considered unattractive and may be disconcerting, flares are a necessary and important aspect of certain plants to properly handle waste process gases that are combustible. At this plant, the role of the flare for the coal gasification process would be to safely dispose of off-specification process gas during startups and shutdowns and on-specification process gas in the event of an upset or malfunction of equipment. Process gases would not normally be flared.

When flaring occurs, it would actually reduce emissions from what would otherwise be emitted during such events if the flare was either not present or "shut down." This is because pollutants in the process gases, such as organic compounds, are destroyed and converted into far less noxious pollutants, like carbon dioxide (CO_2). The permit sets limits for the maximum rates of emissions of different pollutants that may accompany flaring. Because flaring will serve to control pollutants that are of particular concern, flaring would not normally be stopped even in the improbable case that these rates would be exceeded. Rather, CCG would be required to report a deviation from permit terms with excess emissions. IEPA would review the causes of the incident, the corrective actions that were taken, and other relevant information to determine if any enforcement activities are warranted.
The permit appropriately addresses flaring by provisions that address the overall extent of flaring. In addition to limits for the hourly rates of emissions from flaring, the permit also sets limits on the overall emissions of different pollutants on an annual basis. It also requires CCG to develop and maintain a Flare Minimization Plan, to identify and implement actions that minimize the extent of flaring. Flaring due to

malfunctions must be evaluated to identify the root cause of such event to determine whether those causes can be eliminated.

3. If several large sources of emissions are in the same geographic area, how is that handled as far as accountability? I don't understand. And as I talk more about the coal gasification expandability in our area, I don't understand how you can measure these things that aren't independently downwind if you've got multiple producers.

Sophisticated computerized models are used to evaluate or model the combined effect of emissions from multiple sources on air quality. The air quality modeling conducted for this plant included emission data for the proposed plant, emission data for significant existing sources already in the region, and data for background air quality, to account for smaller sources that were not addressed individually. As already discussed, the modeling for this plant showed that it would not be a threat to air quality. The modeling also predicted elevated levels of air quality in the vicinity of certain existing sources but these results almost certainly overstate actual air quality levels. This plant also did not contribute significantly to those elevated levels of air quality predicted by the model.

If another major facility is proposed in the future for the Taylorville area, similar analyses would have to be performed to address the impacts of that proposed facility on air quality. If the initial modeling for that facility shows significant impacts on air quality, this plant would now be one of the existing sources whose emissions would have to be included in the detailed modeling conducted for the proposed future facility to assess its impacts on overall air quality.

4. Considering sequestration of CO_2, what would happen to the CO_2 stored underground if there is an earthquake?

Because of the depth underground at which CO_2 would be sequestered, an earthquake should not pose a concern for catastrophic release of CO_2. However, it is possible that an earthquake could cause damage to the injection well and associated equipment. This is something that would be appropriately considered as part of the design and permitting of the injection well. Of course, it is not possible to know exactly what would happen during an earthquake, if anything, because the location, depth and magnitude of earthquakes vary and earthquakes are uncommon in Central Illinois, which is not part of the New Madrid Seismic Zones located further south.

5. If the Air Separation Unit (ASU) that produces the oxygen for the plant is actually owned by someone other than CCG, would it be covered by this permit or by an additional permit or separate permit?

At this time, the Air Separation Unit is appropriately addressed in the permit for the plant. This is because it is an essential aspect of the plant. Accordingly, the emissions units in the Air Separation Unit, certain vents for oil mist, which would have relatively low amounts of emissions, total less than 1.0 ton/year, are addressed in Section 4.13 of the permit.

Even if the Air Separation Unit would eventually be contracted out and owned by someone other than CCG, it would still be considered part of the plant, as a "support facility." This is because of the Air Separation Unit would be located on the plant site and would perform a critical function for the operation of the plant. The day-to-day operation of the Air Separation Unit would also be coordinated with the operation of the gasification block, so that CCG would in practice determine when the unit would operate and at what level.

6. The Project Summary, on Page 50, states that the limiting factor for the application of carbon capture and sequestration (CCS)[1] for reducing GHG emissions from this project is the availability of a pipeline or geologic formation to use for permanent sequestration of captured CO_2 emissions. However, in September, CCG recently applied for permits to construct and operate two Class VI injection wells near Taylorville for geologic sequestration of CO_2 (see http://www.epa.gov/r5water/uic/tec/index.htm). Please address this apparent inconsistency. USEPA generally considers CCS to be an available control technology for large CO_2-emitting facilities, such as fossil fuel-fired power plants and certain industrial plants with high purity CO_2 streams. As such, if IEPA cannot demonstrate why CCS is technically infeasible for the proposed facility, the BACT analysis should evaluate costs and other impacts of installing and operating a CCS system.

This development does not change the status of geologic carbon sequestration for the TEC. As discussed in detail in responses to other comments on this subject, sequestration continues to be technically infeasible for the TEC. That is, while it is expected that CCG will demonstrate that sequestration is feasible as part of this project, it cannot be assured at this time that this will occur, as must be the case if mandatory permit requirements for geologic sequestration are to be set. In this regard, these Class VI permit applications are only one step in the work that must be successfully completed before any CO_2 can be sequestered. In addition, CCG did provide a cost-evaluation showing that CCS is not cost effective, as discussed in detail in response to other comments on this subject.

7. Before the Illinois legislature and in other contexts, Christian County Generation (CCG) seeks to portray the TEC as a "clean" coal plant in an effort to qualify for subsidies under a proposed state law that, if passed, would effectively require Illinois ratepayers to subsidize the costs of this multi-billion dollar plant. However, CCG's application and the Draft Permit tell a far different tale about the TEC and demonstrate that the visions of that plant being somehow "clean" are little more than a mirage. Most critically, in the context of supporting the state legislation that would subsidize so-called "clean" coal plants, CCG has stated on numerous occasions that it would reduce its carbon dioxide ("CO_2") emissions through carbon capture and sequestration ("CCS") or enhanced oil recovery ("EOR"). Yet in the context of this permitting process, CCG claims that such control of CO_2 emissions is far too uncertain to commit to. IEPA accepted these claims and, as a result, the TEC would be authorized to emit more than five million tons of CO_2 equivalents every year. In addition, the TEC would be permitted to emit significant amount of other pollutants,

[1] The phrases "carbon capture and sequestration" and "carbon capture and storage" (in both cases, CCS) are commonly used with similar meanings, referring to capture of CO_2 in the exhaust stream of an emission unit or process followed by geological sequestration of that CO_2.

including sulfur dioxide, nitrogen oxides, fine particulate matter, and volatile organic matter. The TEC may be many things but, based on the Draft Permit, clean is not one of them.

The TEC is reasonably considered a clean coal plant when appropriately compared to conventional plants that use coal and are of comparable size. In addition, the TEC presents an important opportunity to further pursue the development of CCS and to demonstrate that this technology has developed to the level at which it may be considered feasible and emission limits may be set that rely upon this technology.

IV. EMISSIONS QUANTIFICATION

SO_2 EMISSIONS FROM FLARING

8. SO_2 emissions of the TEC were evaluated focusing on maximum short-term emissions from flaring.[2] These emissions would occur during startups, shutdowns, and malfunctions when off-specification raw syngas is vented to the flare. The Application provided SO_2 emission data for certain "planned startups and shutdowns" but not for malfunctions. My comments first discuss SO_2 emissions during planned startups and shutdowns and then during malfunctions.

This comment, which claims that the number and duration of startup and shutdown events should be limited by the permit, overlooks the fact that the flare is subject to enforceable annual emission limits for SO_2, NOx, CO, VOM, PM, COS, and CO_2e [Condition 4.1.6(b)].[3] These emission limits effectively limit the number and duration of startup and shutdown events, making separate limits on the frequency and duration of these events unnecessary and redundant. Such limits would also act to inappropriately constrain the ability of the source to react to the actual operating conditions of the gasification block during startup and shutdown. In particular, it could lead to situations where actions by operators during a particular startup or shutdown that are required to satisfy the general obligation to minimize emissions "in a manner consistent with safety and good air pollution control practices" would lead to violations of the generic limits that would be set for the duration of startups and shutdowns.

The comment incorrectly claims that CCG modeled 1-hour SO_2 emissions rates that do not match the values referenced in Table B-2.1 of Appendix B of Volume 2 of the Application. The SO_2 emission rate of 9,554 lb/hr referenced in the comment was not from the application for which the permit is being issued.[4] A comparison of the

---

[2] For SO_2, CCG must demonstrate with air quality modeling that air quality with the SO_2 emissions from the TEC would continue to comply with the PSD increments for SO_2, which apply on a 3-hour and 24-hour basis, and the NAAQS for SO_2, which apply on a 1-hour, 3-hour, 24-hour, and annual basis. For this project, the most difficult to satisfy is the 1-hour SO_2 NAAQS, so my evaluation for SO_2 emissions focused on maximum short-term emissions of SO_2 from flaring

[3] **The continuous flare gas flow rate monitoring [Condition 4.1.8-1(a)(i)(A)], continuous H_2S and CO content monitoring [Condition 4.1.8-1(a)(i)(B)], and periodic flare gas heat content and composition monitoring [Condition 4.1.9(d)] will collectively enable demonstration of continuous compliance with the annual emission limits.**

[4] **CCG also submitted a second application that addressed a plant that would have had three gasifiers, rather than two as now planned. CCG has chosen not to pursue that second application. Accordingly, none of the information addressing that concept for the TEC is now relevant, including the SO_2 emission rate for the flare cited in this comment.**

modeled flare emission rates to the emission rates in Table B-2.1 of the appropriate application shows that the correct emission rates were modeled.

9. During startup and shutdown of the gasifiers, there are periods during which raw syngas cannot be fed to the acid gas removal ("AGR") unit due to process constraints. During these periods during startup and shutdown, as well as malfunction, the raw syngas is routed directly to the flare for combustion. The flare converts sulfur present in the raw syngas into SO_2. The application includes information on the expected number and duration of routine, planned startup and shutdown events for the gasifiers but they would not be limited by the Draft Permit.

The air quality modeling assumed certain maximum 1-hour average emission rates in determining the SO_2 air quality impacts of these startup and shutdown events. The IEPA modeled the highest SO_2 emission rate reported in this table, or 9,036 lb/hr. However, CCG modeled a 1-hour SO_2 emission rate of 9,554 lb/hr. This latter value is not supported in the application or permit record. There are two major problems with these modeled emission rates. First, the application does not support these emission rates. Information in the record and available from public sources indicates that planned startup and shutdown emissions are significantly underestimated. Second, the Draft Permit does not assure that these SO_2 emission rates will be achieved in practice.

As related to emissions from planned startups and shutdowns, the application lays out a complicated looking formula for the determination of the short-term SO_2 emissions summarized in Table C-3 in Appendix C of the application.[5] However, on inspection, the formula only converts the process rates for H_2S (n_{H2S}) and COS (n_{COS}) in pound-moles per hour ("lb-mol/hr") into pounds per hour of SO_2, assuming 98% is released at the flare.[6] The formula does not provide the underlying assumptions for the process rates, such as coal sulfur content, length of time raw syngas is vented to the flare, and composition of raw syngas. The application also provides no support for the molar process rates themselves.[7] The equations in the application[8] just convert process data in pound-moles per hour into SO2 emission data in pounds per hour, with the addition of a small amount of sulfur from the use of supplemental fuel to boost combustion efficiency for low Btu syngas.

The assumptions used to derive the process rates are not disclosed in the permit record and are unsupported. Presumably, the process rates came from material balances that were based on numerous assumptions that should be subject to agency and public review and specified as permit conditions. These include the design and maximum sulfur content of coal, the maximum coal feed rate for each hour during the startup/shutdown event, and sulfur retention, if any, in the slag. Because none of the information required to truth the claimed maximum SO_2 emissions was provided, I bounded the likely maximum SO_2 emissions using information scattered throughout the record.

[5] Ap., v. 1, Appx. C, Table C-3, p.C-8, SO_2 Emissions.
[6] Ap., v. 1, Appx. C, p. C-13, Table C-3.9.
[7] Stated without citation in the Ap., v. 1, Appx. C, Table C-3.9, p.C-13.
[8] *See* equations in Ap., v. 1, Appx. C, Table C-3, p. C-38, equations listed under heading: **"**SO_2 Emissions."

The application provides an acceptable level of detail for short-term SO_2 emissions, as addressed by this comment. CCG was not required to include the underlying assumptions used to derive the process rates used in its emission calculations (i.e., the sulfur balance around the gasifier). As Appendix C indicates that the emission data is based on available process data, sufficient information is provided to support the data for SO_2 emissions of the flare. Regardless, the permit includes explicit limits on SO_2 emissions from the flare during startup and shutdown (Conditions 4.1.6(c) and (d)). CCG must operate the TEC to comply with these emission limits irrespective of the calculations underlying the emissions data provided in the application.

Moreover, since this permit is a construction or "pre-construction" permit, it is unrealistic to expect that detailed data of the type sought by this comment would be available for inclusion in the application and submittal by CCG. The permit specifies the emission rates and other requirements that must be met by the various emission units at the plant. Until the permit was issued setting those requirements or "specifications" for the plant, CCG could not know with certainty what those equipment specifications would be. CCG also could not finalize the plans for the plant so as to have final process design information. Preliminary discussions between CCG and technology and equipment vendors that have occurred are not binding on either CCG or the vendors. Moreover, information from those discussions could not be considered reliable even if CCG elected to provide it. In summary, the application for the TEC was appropriately considered sufficient and complete without the further documentation sought by this comment.

Although all of the underlying assumptions and data inputs used to derive the hourly and annual flare SO_2 emission rates need not be included in the application, Section C-3 of Appendix C provides a clear and understandable basis for the derivation of the flare SO_2 emission limits in the permit. The underlying process data for H_2S and COS in the off-specification process gas routed to the flare during gasifier startup and shutdown events were derived using hour-by-hour heat and material balance data developed by CCG based on data from Siemens and other prospective vendors as part of the preliminary design for the TEC (refer to Section 3.3.1 of the Application). The comment mentions some of the relevant input parameters that were entered into the process simulation models to develop preliminary plant-wide heat and material balances, but there are many other factors that influence the volume and composition of process gases generated by the gasifiers and syngas conditioning train equipment during startup and shutdown. A multi-million dollar front end engineering design (FEED) study involving thousands of labor hours from qualified engineers was commissioned for the project as part of the facility cost report.[9] A significant task within this FEED study was to incorporate preliminary design information from prospective vendors into a plant-wide heat and material balance that could be used both for facility costing and environmental permitting.

10. The maximum 1-hour SO_2 emissions must be used in the 1-hour SO_2 PSD increment and NAAQS modeling. My review indicates that this was not done because of the approach that

[9] **Illinois Commerce Commission Tenaska Facility Cost Report, Exhibit 2.0, FEED Study Summary available at http://www.icc.illinois.gov/electricity/tenaska.aspx.**

was taken to conversion of sulfur in the gas being flared to SO_2. The startup/shutdown flaring calculations assume that only 98% of the sulfur compounds in the flared gases is combusted to form sulfur dioxide (SO_2) and the balance is emitted as the original sulfur compound (H_2S, COS). The 98% assumption is based on unsupported guidance by the Texas Commission of Environmental Quality ("TCEQ")[10], rather than measurements at Siemen's gasification pilot plant in Freiburg, Germany, where hundreds of coal samples have been tested. It is common in permitting to assume 100% conversion of sulfur to SO_2 when calculating SO_2 emissions.[11] This is especially true and critical where the assumption is not assured through an enforceable permit condition.

Condition 4.1.2-1(a)(v) of the Draft Permit does not require that the flare be designed to achieve no more than 98% sulfur conversion to SO_2, but rather to achieve 98% removal of CO and 99% removal of methanol. In fact, the requirement to achieve 98% CO destruction and 99% methanol destruction are at cross purposes with the requirement to limit sulfur conversion to 98%. The operating procedures include the use of supplemental fuel to improve combustion efficiency, which increases the conversion of sulfur to SO_2[12].

The TCEQ flare permitting guidance document used as the basis for the 98% sulfur conversion efficiency for the flare is supported by the recommended emission calculation procedures in USEPA's recently issued *Emission Estimation Protocol for Petroleum Refineries*.[13] RTI International developed this document for USEPA to provide recommendations to petroleum refineries about how best to respond to an Information Collection Request (ICR) issued by USEPA. Issuing the ICR and reviewing the corresponding responses from petroleum refineries currently operating in the U.S. is a first step by USEPA in the process of developing future NSPS and NESHAP for this industry. As discussed elsewhere in this document, SO_2 emissions from a flare should be calculated based on: 1) the flare gas flow rate, 2) the concentrations of various sulfur compounds, and 3) the conversion efficiency of the flare for converting sulfur compounds to SO_2. The flare sulfur compound conversion efficiency (K_{eff} in Equation 6-1 of the USEPA refinery protocol) should be set equal to the flare combustion efficiency (F_{eff}), and the flare combustion efficiency for a properly operating flare can be assumed to be 98%. Accordingly, it was not necessary for the flare emission calculations for the TEC to reflect complete conversion of sulfur to SO_2. The fact that others may have chosen to make such an assumption does not show the subject data in the application for the TEC was inappropriate, and the comment does not provide any technical justification/support that an industrial flare will achieve 100% conversion of reduced sulfur compounds to SO_2.[14]

---

[10] Ap., v. 1, Appx. C, Table C-3, p. C-10 (citing for $\%CE_{H2S}$: TCEQ, Air Permitting Guidance for Chemical Sources: Flares and Vapor Oxidizers, October 2000).

[11] 'For example, Power Holdings for its proposed coal-to-SNG facility assumed that all of the H_2S and COS would convert to SO_2 during flaring. See Power Holdings of Illinois, LLC, Flare Emissions — Evaluations (Nov. 5, 2008) at 3; *see* also, Emission Estimation Technique Manual for Oil & Gas Exploration & Production, February 1999; http://www2.unitar.org/cwm/publications/cb1/prtr/pdf/cat5/Australia foilas.pdf. (Commenter's Exhibit 2)

[12] Ap. v. 1, Appx. C, Table C-3, pp. C-8 and C-9 (equation showing Q_{FG} or supplemental fuel, natural gas, which is added to boost combustion).

[13] RTI International submitted to USEPA OAQPS, Emission Estimation Protocol for Petroleum Refineries, September 2010.

[14] The contention accompanying this comment that Power Holdings assumed complete conversion of H_2S and COS in the flare gas to SO_2 emissions is unfounded based on the material that was referenced. The only statement in this material addressing sulfur conversion efficiency is "when going thru the Flare; CO mostly goes to CO_2, H_2 goes to H_2O, CH_4 goes to CO_2, but H_2S and COS all go to SO_2." The phrase "H_2S and COS all go to SO_2" is vague and unsupported based on the rest of the discussion in the material, and therefore, this statement should not be used to formally assess whether Power Holdings assumed a 98% or 100% conversion efficiency of sulfur to SO_2.

Moreover, even if CCG were to have assumed complete conversion of sulfur in the flare gas to SO_2, the maximum hourly emission rate from the flare would only increase by a small amount to 9,220 lb/hr. The conservative assumptions used for the coal sulfur content and volume of raw syngas routed to the flare during the initial phase of a cold plant startup used in the derivation of the hourly flare BACT limit of 9,036 lb/hr will ensure that the actual emissions from the flare will remain below the permit limit even if CCG did assume that all of the sulfur present in the flare gas were converted to SO_2. Also, this small change in hourly emissions from the flare is not expected to influence the conclusions of the 1-hr SO_2 NAAQS analysis because of the various conservative assumptions made by CCG for the modeling setup. For example, CCG assumed that the worst-case flare, SRU thermal oxidizer, and AGR vent hourly SO_2 emissions during a cold plant startup all occur during the same hour when in actuality the highest SO_2 emissions from the SRU thermal oxidizer and AGR vent will not occur until after the syngas has been fed forward into the process and raw syngas flaring is no longer being flared.

The comment's claim that the permit should limit the sulfur conversion efficiency of the flare to no more than 98% to maintain consistency with the efficiency value used in the derivation of the flare SO_2 limits is ridiculous. This is because it would restrict the performance of the flare, contrary to operation in accordance with good air pollution control practice to minimize emissions.

11. The SO_2 emissions were also understated because of the data that was used for the composition of the waste gas that would be flared. The SO_2 emission calculations for startup and shutdown assume that H_2S and COS are the only sulfur compounds present in the raw syngas. Traces of other sulfur compounds have been reported in raw syngas, including organic sulfur compounds like mercaptans and dimethyl sulfide.[15] The record does not contain complete sulfur characterization data for the syngas but only an unsupported assertion that only H_2S and COS are present. This is inexcusable as Siemens has tested hundreds of different coals in its pilot scale gasification system in Freiburg, Germany. The composition of raw syngas is well known and should be presented in the application and key components limited in the permit as the emissions depend directly on syngas composition and measurement is routine. There is no evidence that the SO_2 emissions data in the application for startup and shutdown of the gasifiers took into account *all* sulfur compounds in the gas apart from the unsupported assertion that it did. This claim is impossible to verify with the available information.

CCG indicates that the SO_2 emission data for the flare reflects information for raw syngas composition provided by Siemens, which indicates that sulfur compounds other than H_2S and COS will not be present in measurable quantities. As the comment observes, Siemens has a pilot gasification plant where it has conducted extensive research on its gasification technology. As such, it is reasonable for the application to have relied on information from Siemens for the composition of the raw syngas that would be produced at the TEC. The fact that "other organic sulfur compounds" have been measured in raw syngas from certain coal gasification processes certainly does

[15] Tim Lieuwen, Vigor Yang, and Richard Yetter (Eds.), Synthesis Gas Combustion. Fundamentals and Applications, 2010, Sec. 6.3 and Christopher Higman and Maarten van der Burgt, Gasification, 2nd Ed., Elsevier, 2008, Table 6.2.

not show that the information from Siemens is not reliable. This is because it would not reflect the Siemens' gasification technology that would be used at the TEC.[16]

12. The SO_2 emissions were also understated because of the data that was used for the sulfur content of the coal feedstock for the plant. The SO_2 emitted at the flare originates in the coal. During gasification, essentially all of the sulfur in the coal is converted into H_2S and COS. During normal operation, this sulfur is removed from the syngas in the Acid Gas Removal Unit and then converted into liquid sulfur. However, during cold startups, shutdowns and malfunctions, raw syngas is diverted directly to the flare for a portion of the startup and shutdown, where the sulfur is converted into SO_2. This diversion occurs before there is any sulfur removal. Thus, to estimate maximum SO_2 emissions from flaring during non-routine operations, one must know how much coal is gasified during each hour, the amount of sulfur in the coal, and the length of time raw syngas is vented directly to the flare. None of this information is reported in the permit record. My calculations, summarized below, indicate that the modeled SO_2 emissions are not the maximum 1-hour emissions.

The application does not disclose the assumed sulfur content of the coal gasified during non-routine operation, rendering the maximum reported SO_2 emissions unsupportable. The only information in the permit record about the coal is: (1) the "design coal supply... would be Illinois Basin coal nominally containing 4.4 percent sulfur by weight;"[17] (2) that it contain at least 1.7 lb sulfur per million Btu ("mmBtu") (equal to about 1.7% for a heat content of 10,000 Btu/lb);[18] and (3) that it presumably will be from the Herrin coal seam. It is not clear whether "nominal" is meant to refer to the average sulfur content of the coal or the maximum, but in either case, the Draft Permit would not limit the maximum sulfur content of the coal to be used at the TEC. At a minimum, IEPA must clarify and limit the maximum coal sulfur content.

In addition, to estimate SO_2 emissions at the flare, one must know the amount of coal sent to the gasifier during each hour of the startup, shutdown, and malfunction events. This information is also not disclosed in the permit record. Thus, there is no basis to conclude that the maximum 1-hour SO_2 emissions have been calculated. My analysis, outlined below, indicates the proffered maximum 1-hour SO_2 emission rate is far from the maximum potential that must be used in the PSD modeling.

I researched Herrin coal, which the application cites as the basis for HAP emission estimates.[19] The U. S. Geological Survey describes this coal as having a sulfur content that

---

[16] **This comment cited *Gasification*, by Higman and van der Burgt, as a basis for the presence of other sulfur compounds in the raw syngas at the TEC. However, this work actually confirms the information provided by Siemens, as it distinguishes between high-temperature gasification processes, like the Siemens' process used at the TEC, and low-temperature gasification processes, "In high-temperature processes, all sulfur components in the feed are converted to H_2S and COS. Other compounds, such as S_X and CS_2, are essentially absent. This is not the case in low-temperature processes, where tars and other species have not been completely cracked."**
This work goes on to explain that for high-temperature gasification "under typical gasification conditions H_2S is the dominant species, and approximately 93-98% of the sulfur is in this form with the rest being COS."
In its reference to this work, it is apparent that this comment has overlooked the role of gasifier operating temperature in raw syngas composition, which explains why Siemens addressed only H_2S and COS in the data it provided for syngas composition.
Note 1: Higman, Christopher and van der Burgt, Maarten, *Gasification*, 2nd Edition, Elsevier, Inc., 2008, see p. 233 for quoted materials.
Note 2: The Siemens single stage, dry-fed, slagging gasifiers selected for the TEC operate at temperatures in the range of 2,350 to 3,250 ˚F while low-temperature processes, like Lurgi dry bottom gasifiers, operate at temperatures in the range of 1,000 to 1,800 ˚F.

[17] Draft Permit, Finding 1(c).

[18] Application., v. 1, p. 5-8.

[19] Ap., v. 1, p. 12-2 and Appendix C, p. C-82, Table C-22.2.

is "relatively high as compared to other United States coals." [20] The mean sulfur content of Herrin coal is reported as averaging 3.0% and ranging from 0.3% to 14.5%, based on 2,517 samples.[21]

I estimate the average sulfur content of the coal assumed in CCG's emission calculations is about 3.75%. This is derived from the ratio of the amount of sulfur leaving the plant to the amount of coal gasified. Assuming no sulfur in the slag[22] and other inputs, the amount of sulfur entering the plant in the coal is equal to the sum of the amount of liquid sulfur produced (190 ton/day)[23] and the amount of sulfur emitted as SO_2, H_2S, and COS, but not derived from fuel firing (*e.g.*, flare pilot, auxiliary boiler) (358.5 ton/yr)[24]. Condition 4.1.5-1(a) of the Draft Permit would allow the TEC is permitted to gasify 1,860,000 ton/yr of coal. Thus, the average amount of sulfur in the gasified coal is at least 3.75%,[25] or about 25% higher than the average for Herrin coal.

The assumed coal sulfur content during non-routine operation is unknown. However, it would not be lower than the average as the BACT analysis concluded (I believe erroneously, as discussed later) that the use of low sulfur coals during startup is not feasible[26]. I back-calculated the coal sulfur content for the maximum one-hour SO_2 case, 9,036 lb/hr of SO_2, using information scattered in the Application, Appendix C.

My calculations indicate that the Application assumed the average annual case coal sulfur content of 3.75% and 60% control efficiency during cold startup, the worst case for SO_2 emissions reported in the Application[27]. Finding 1(c) in the Draft Permit would indicate the design coal would "nominally" contain 4.4% sulfur as received at the plant. Thus, the non-routine emission calculations underestimated SO_2 emissions.

The 60% control efficiency embedded in these calculations is consistent with the BACT analysis which concluded without proof that "shifting raw syngas forward" as quickly as possible (and the time to do this was not disclosed) would reduce SO_2 emissions for a cold startup event from 170,000 pounds per event ("lb/event") to 72,000 lb/event or by 60%[28]. However, this operating procedure is not required in the Draft Permit or supported by any calculations, test data, or flow diagrams to explain how it would work. If this procedure is

---

[20] R.H. Affolter and J.R. Hatch, Characterization of the Quality of Coals from the Illinois Basin, Chapter E of: Resource Assessment of the Springfield, Herrin, Danville, and Baker Coals in the Illinois Basin, U.S. Geological Survey Professional Paper 1625-D, p. E-15 and Table *5;* http://pubs.usgs.gov/pp/p1625d/508/Chapter E 508.pdf. (Commenter's Exhibit 3)

[21] This suggest that CCG has a wide range of coal sulfur contents to choose from.

[22] Coal gasification slags are reported to contain 0.01% to 0.5% sulfur. *(See* MS. Najjar and D.Y. Jung, Bench-Scale Test Results and Calculation Procedure for In-Situ Sulfur Capture via Sorbent Addition to Coal Slags under Partial Oxidation, http://www.anl.gov/PCS/acsfuel/preprint%20archive/Files/35_3_WASHINGTON%20DC_08-90_0615.pdf. (Commenter's Exhibit 4) Assuming the maximum slag production rate of 4,500 ton/yr (Ap., v. 1, pdf 302), up to 22.5 ton/yr of sulfur would be partitioned into the slag. This is a very small amount, compared to the amount of sulfur that is partitioned into the various exhaust gases and liquid sulfur product.

[23] Application v. 1, Appendix C, p. C-97.

[24] The amount of sulfur emitted, but not derived from fuel firing (*e.g.*, flare pilot, auxiliary boiler, heater), is the sum of the sulfur emitted as SO_2 + H_2S + COS based on the Ap., v. 1, Table 3-2 and Table C-23.1, p. C-86: 32/64(696.87-0.79) + 32/34(8.78) + 32/60(4.11) = 358.5 ton/yr sulfur.

[25] Sulfur content of coal: 100[((190 ton S/day x 365 day/yr) + 358.5 ton S/yr)/1,860,000 ton coal/yr) = 3.75%.

[26] Ap., v. 1, p. 6-10.

[27] The amount of coal gasified during the maximum one hour cold start: [(2,000 MMBtu raw syngas/hr (Table C-8)) / (0.0027 mmBtu/lb raw syngas (p. C-83))] x (0.29 lb coal/lb raw syngas) x (ton/2,000 lb) = 107 ton/hr of coal is gasified during the maximum one-hour cold start, or about half of full production. The gasification of this coal produces 9,036 lb/hr of SO_2. Thus, the sulfur content of the coal would be: (100)(0.5 lb S/lb SO_2)(9,036 lb SO_2/hr)/(107 ton/hr)/(2,000 lb/ton) = 2.11% sulfur**.** If one assumes that 60% of the coal sulfur is removed by the feed forward process described in the Application at 6-6 and converted into liquid sulfur, then the sulfur content of the coal would be 2.11/0.6 = 3.5%. This is consistent with the average coal sulfur content estimated elsewhere for a cold startup.

[28] Ap., v. 1, p. 6-6.

not used, or is not successful, the maximum hourly SO_2 emissions correspond to a coal sulfur content of only 2.1%, indicating a significant underestimate. Calculating the maximum hourly emissions assuming average coal sulfur content, without the undocumented and unpermitted feed forward procedure, but otherwise using CCG's assumptions, yields a maximum hourly SO_2 emission rate of 9,036/0.60 = 15,060 lb/hr SO_2 based on 3.75% S in the coal.

Alternatively, the Draft Permit does not limit the amount of sulfur in the coal. If the CCG chose to use a higher sulfur coal than 3.75%, say the "nominal" 4.4% design coal, the maximum SO_2 emissions during a cold startup would increase from 9,036 lb/hr to 10,602 lb/hr, assuming 60% reduction from the feed forward procedure and 17,670 lb/hr without the feed forward procedure.

In sum, the worst case coal sulfur content was not used to estimate worst-case, 1-hour SO_2 emissions. Further, an undocumented procedure, forward shifting of raw syngas, was assumed without support, to further lower the maximum 1-hour SO_2 emissions. Thus, I believe the modeling has significantly underestimated maximum 1-hour SO_2 impacts. The sulfur content of the coal burned during startups, shutdowns, and malfunctions can range up to 14.5%. The permit should limit the sulfur content of the coal and this limit must be the basis for estimating the maximum 1-hour SO_2 emissions during non-routine operations.

The comment claims that the amount of coal gasified and the coal sulfur content during each hour that raw syngas is being flared is not provided in the application when in fact this information can be discerned from information in the application.[29]

As discussed below with respect to the coal moisture content used in the PM emission calculations for coal transfer points, the comment's arbitrary references to the range of sulfur content in Herrin coal, with values significantly above the sulfur content used by the TEC in the material balances and corresponding flare emission calculations are not meaningful in light of the site-specific nature of the sulfur content estimate developed by CCG and the hourly SO_2 flare emission limit in the permit. With an hourly SO_2 flare limit and continuous monitoring required for the flow rate and sulfur content of the process gas routed to the flare, a restriction on the sulfur content of the coal gasified is unnecessary.

The comment claims that 3.75% coal sulfur content was used in the flare SO_2 emission calculations, but in fact, as shown with appropriate calculations, the coal sulfur content

[29] **The heat input rate of raw syngas to the flare during the worst-case hour of a cold plant startup can be determined from the information in Tables C-3.8 and C-3.9 of Appendix C. The maximum hourly heat input rate of raw syngas and supplemental fuel gas combined used in the hourly potential NOx emission calculations is 2,000 mmBtu/hr (refer to Table C-3.8) and the maximum heat input rate of supplemental fuel gas during this same period used in the hourly potential SO_2 emission calculations is 905.70 mmBtu/hr (refer to Table C-3.9). This gives a maximum raw syngas heat input rate of 1,094.3 mmBtu/hr which can be converted into mass flow rate of raw syngas based on the heating value included in Section C-22 of Appendix C (i.e., 1,094.3 mmBtu/hr/0.00273 mmBtu/lb = 400,837 lb/hr). In turn, the raw syngas mass flow rate can be converted into a dry coal throughput using the ratio of coal feed rate to raw syngas production rate also in Section C-22 of Appendix C [i.e., 400,837 lb raw syngas/hr × 0.287 lb as-received coal/lb raw syngas × (1 - 11% coal moisture content) × 1 ton/2,000 lb = 51.2 ton/hr]. The coal sulfur content used in the heat and material balances can be derived from the flare maximum hourly SO_2 emission rate of 9,036 lb/hr and the dry coal throughput rate during this period of cold plant startup derived above (i.e., 9,036 lb/hr × (32 lb S/lb-mol/64 lb SO_2/lb-mol) × 1 ton/2,000 lb ÷ 51.2 ton/hr = 4.4% on a dry basis).**

used in the flare emission calculations is 4.4% on a dry basis.[30] Using the maximum sulfur production rate from the SRU in conjunction with the maximum annual coal throughput and the plant-wide annual potential SO_2, H_2S, and COS emission rate is not an appropriate or accurate methodology for assessing the assumed coal sulfur content of coal fed to the gasifiers during a could plant startup. First, this methodology would at best determine on average over the course of a year what the coal sulfur content may be, but would not identify the coal sulfur content during the few hours of cold plant startup when raw syngas is flared. Second, the coal throughput used in this calculation is not in consistent terms with the coal throughput during a cold plant startup, but rather reflects the annual potential coal throughput to the plant.

To support its claim that the hourly SO_2 emissions of the flare are underestimated, this comment relies upon a complicated analysis to derive a sulfur content for the coal feedstock for the plant that is different from that presented in the application. These calculations are not accurate and utilize incorrect input data. The amount of coal gasified during the maximum one hour cold start is not 107 ton/hr as calculated in the comment because the raw syngas heat input rate assumed in the calculations is incorrect. The contribution from supplemental fuel gas is included in the raw syngas rate in Table C-3.8, 2,000 mmBtu/hr. With an incorrect coal throughput rate, the calculated coal sulfur content of 2.11% is also incorrect. The comment also misuses the 60% control efficiency of the cold plant startup methodology developed by CCG. As explained in Section 6.1.1.1, on page 6-6 of the application, CCG has developed a preliminary cold plant startup methodology which minimizes the amount of raw or "sour syngas" that would be flared as compared to the base case alternative startup method in which sour syngas would be flared until the Shift Unit has achieved the desired reaction conditions and associated syngas quality. This control efficiency expressed on a per event basis cannot be applied to the raw syngas flaring since no sulfur controls are in place during this brief period of the cold plant startup.

CCG has developed preliminary gasification block startup and shutdown methodologies that were applied in the material balances used to derive the annual flare SO_2 BACT limits. Once the final design of the plant is completed, CCG will either have to develop standard operating procedures that include these proposed methodologies directly or will have to develop alternative procedures that are at least as effective at minimizing emission as the methodologies envisioned when the SO_2 limits for the flare were established. The monitoring requirements for flow and H_2S content for waste gas to the flare and sampling requirements for the total sulfur content of raw syngas will ensure that CCG has a complete record of the sulfur flow rate to the flare and will be able to verify compliance with the SO_2 emission limits in Condition 4.1.6(b) for the flare. Accordingly, absent implementation of the "feed forward" methodology described in the application (or an equally effective methodology), CCG should not be expected to comply with the annual SO_2 emission limit for the flare in the permit. As such, it is not necessary for the permit to explicitly require use of "feed forward."

---

[30] **Finding 1(c) in the Draft Permit incorrectly indicated the sulfur content of the design coal is 4.4 % on an as-received basis, when it is 4.4 % on a dry basis. Given the potential for misunderstanding resulting from this information for the design feedstock for the plant, information for sulfur content of the design coal is not included in the issued permit.**

The worst-case hourly SO_2 emission rate from the flare were projected based on clearly documented information in the application, is included as an enforceable permit limit, and was used in the modeling to demonstrate compliance with the 1-hour SO_2 NAAQS. Thus, the 1-hour SO_2 modeled impacts are not underestimated and the permit includes sufficient requirements to ensure the modeled emission rates will not be exceeded in practice.

13. The 1-hour SO_2 NAAQS modeling must be based on the maximum amount of SO_2 emitted in any one-hour time period. The maximum value included in the modeling and calculated in Appendix C is 9,036 lb/hr, which occurs during a cold plant startup[31]. This value does not correspond to the maximum hour. The application provides this value as a 3-hour average.[32] The Project Summary, page 9, also reports this as a 3-hour average. This means the value in the maximum hour could be much higher than the 3-hour average, so long as the emission rates in the other two hours are low enough to average it out.[33] This scenario is plausible given the application indicates that feed forward shift methodology will be used to reduce SO_2 emissions by 60% during cold startups.[34]

Moreover, as also explained in the application, sour unshifted syngas will be flared for a brief duration before this shift forward procedure can be implemented. The extent of this time is not disclosed and the Draft Permit would not limit the length of time during startup when raw syngas can be sent to the flare. The hour that includes sending raw syngas directly to the flare would be the maximum 1-hour SO_2 emission rate. If raw syngas is vented to the flare for one full hour, the SO_2 emissions in that hour would be 9,036 lb/hr/0.6 =15,060 lb/hr. The value that should be modeled in this case would be 15,060 lb/hr, not the 3-hour average of 9,036 lb/hr.

The Condition 4.1.6(b) of the Draft Permit establishes 9,036 lb/hr as an hourly limit on total SO_2 emissions from the flare, without stating an averaging time. However, exceedances of this limit would never be discovered. The Draft Permit does not require any monitoring of SO_2 emissions from the flare. The Draft Permit also does not set limits on any of the parameters required to calculate flaring SO_2 emissions from inputs.

The SO_2 emissions, for example, were calculated in the Application using undisclosed material balances that included coal sulfur content and coal throughput. The Draft Permit does not set limits on these parameters. Alternatively, SO_2 emissions could be calculated from total measured sulfur flow to flare times percent conversion to SO_2. However, the Draft Permit requires monitoring only one component of total sulfur sent to the flare, H_2S, rather than H_2S plus COS (reduced sulfur compounds). Omission of COS excludes 13% of the SO_2 from the calculation.

[31] Ap., v. 1, Appx. C, Table C-3.3, p. C-11, column "(max. lb/hr)" for SO_2
[32] Ap., v. 1, p. 6-11.
[33] For example, the maximum hour could be double the average or 18,072 lb/hr, so long as the other two hours making up the average were half the 3-hour average or (18,072 + 4,518 + 4,518)/3 = 9,036 lb/hr.
[34] The application states: "... sour syngas is fed forward to the shift unit and the shift unit is producing on-specification shifted sour syngas that can be fed to the AGR unit. Once it has determined the raw syngas is of suitable quality to be fed forward, it will bypass the shift unit and will be fed directly to the LTGC unit. This operating practice reduces the SO_2 emission rate during a cold plant startup from more than 170,000 lb/event to less than 72,000 lb/event." Application, Volume 1, p. 6-6

Further, the Draft Permit does not limit the sulfur to SO_2 conversion, assumed to be 98% in the application, or require that the conversion efficiency be tested, so even if the total sulfur sent to the flare were monitored (H_2S + COS), it could not be used to make an accurate estimate of actual SO_2 emissions from the flare. Greater than 98% conversion of the sulfur to SO_2 is feasible. Under the terms of the Draft Permit, there would be no way to detect higher conversion.

As Condition 4.1.6(b) does not specify an averaging period for the hourly flare SO_2 emission limit, this limit applies on a 1-hour block average basis. This limit is accompanied by monitoring requirements for the flow rate and sulfur content of waste gas sent to the flare, which will enable the actual mass of sulfur in the waste gas sent to the flare to be determined. If in routine practice, CCG seeks to rely on less than complete conversion of sulfur to SO_2 when calculating SO_2 emissions and assessing compliance, its compliance practices would be subject to review as part of the processing of the Title V permit for the plant.

Finally, the permit indicated that the hourly limits for the flare apply on an hour-by-hour basis, it should be apparent that the Project Summary was in error as it indicated that these limits apply on a 3-hr rolling average basis.

14. SO_2 emissions were also understated because emissions associated with malfunctions were not addressed. The application estimated emissions during one planned cold start, one major plant shutdown, and 12 additional individual planned maintenance gasifier startups and shutdowns per year. These emissions did not include those that occur during malfunctions, which can be substantially higher than during planned events. Thus, the air quality modeling also did not include malfunction events and thus did not model the maximum 1-hour impacts.

A malfunction is any unplanned emergency relief in which the plant operators would have to vent emissions to the flare due to non-routine operating conditions, including the failure or probable failure of equipment that needs to be repaired or exchanged, loss of electrical power, loss of water, or pressure surges, among others. The application is silent on these types of events.

As malfunctions are unplanned, the duration of the events and the amount and type of emissions could be very different than assumed for the planned startups and shutdowns. If malfunction-related emissions are excluded from the PSD modeling, the offsite ambient SO_2 concentrations will be underestimated. While the Draft Permit would not exclude malfunction events from the flaring emission limits (Condition 4.1.6(b)), exceedances of these limits during malfunctions would never be discovered as the monitoring would be inadequate to identify them.

Unplanned releases due to emergency conditions have been widely documented in the coal conversion industry and are not rare occurrences. They occur as a result of harsh processing conditions unique to coal gasification due to high concentrations of substances, such as ash, slag, sulfur compounds, and various organic acids, that corrode, erode and plug equipment,

such as heat exchangers, pumps and compressor.[35, 36] Indeed, a reliability study by Siemens for Taylorville indicates poor availability during the first two years of operation, 55-65% during the first year and 75-85% during the second year.[37] This indicates the potential for significant malfunction events during these first two years of operation. The plant must comply with all permit limits during this period. There has been no demonstration in the permit record that this is feasible.

This is because the permit record does not contain any of the information required to estimate emissions that would occur during these malfunction events. It is likely, for example, that a complete power outage would result in much higher SO_2 emissions than those estimated for the planned cold startup. These maximum emissions must be calculated and included in the modeling. They are known to CCG, which would require this information to design the flare, vents and connecting pipelines.

Malfunction scenarios can be identified and planned for using, for example, fault tree analysis or failure mode effect analysis, to identify possible failure modes in design, operation or maintenance. These types of analyses are used to design the flare system itself. Thus, emissions from malfunctions can be estimated, included in potential to emit calculations, and air quality modeling. However, the permit record in this case does not include the information required to estimate these emissions. Malfunction emissions have been calculated for other coal gasification projects.[38, 39, 40, 41]

---

[35] Neville A.H. Holt, Operating Experience and Improvement Opportunities for Coal-Based IGCC Plants, Materials at High Temperatures, v. 20, no. 1, pp. 1-6, 2003; W. Schellberg and others, World's Largest IGCC Celebrates 10th Anniversary, 25th Annual International Pittsburgh Coal Conference, September 29 - October 2, 2008 (Commenter's Exhibit 5); EPRI, Evaluation of Alternative IGCC Plant Designs for High Availability and Near Zero Emissions, December 2006 (Commenter's Exhibit 6); Neville A.H. Holt, IGCC Technical Status, Trends and Future Improvements, ACS Meeting, San Francisco, March 2000. (Commenter's Exhibit 7)

[36] According to a recent presentation, the gasifiers at the Puertollano, Spain IGCC plant experienced unplanned outages in 2007 for 12.8% of the time they would otherwise be available, compared to 8.6% planned outages. The Air Separation Unit ("ASU"), which will also be used at the TEC, experienced unplanned outages in 2007 of 24.4% compared to planned outages of 1.4%
K. Radtke, M. Heinritz-Adrian, M. Hooper, B. Richards, PRENFLO: PSG and PDQ, Latest Developments based on 10 Years Operating Experience at Elcogas IGCC, Puertollano, Spain, Presentation at Gasification Technologies Conference, Washington, D.C. (October 5-8, 2008), p. 13 (Commenter's Exhibit 8); M. Bevilaacqua and others, Monte Carlo Simulation Approach for a Modified FMECA in a Power Plant, Qual. Reliab. Engng. Int., v. 16, 2000, pp. 313-324. (Commenter's Exhibit 9)

[37] Siemens Operations and Maintenance Reliability Availability Maintenance Analysis, p. 3. http://www.icc.illinois.gov/downloads/public/en/Exhibit%205.5%20-%20Siemens%20Operations%20and%20Maintenance%20Reliability%20Availability%20Maintenance%20Analysis.pdf. (Commenter's Exhibit 10)

[38] For example, the application for the Southeast Idaho Power facility estimated the duration and frequency of events based on whether they were caused by upsets downstream, upstream, or at the acid gas removal unit, estimating a total of 92 hours of upsets per year. Southeast Idaho Power, Permit Application Appendix D, p. 34. http://www.deg.state.id.us/AIR/permits forms/permitting/pcaec/ayy d 0408.pdf, (Commenter's Exhibit 11)

[39] The FutureGen project grouped and estimated upsets by source of the problem: the air separation unit, the gasifier, the acid gas removal unit, the Claus unit, or the power island; it further estimates annual upset frequency for each source type, FutureGen Final EIS, November 2007, Appendix. E, p. E-4, 5. http://www.netl.doe.gov/technologies/coalpower/futuregen/EIS/Appendix%20E%20-%20Air%20Modeling%20Protocol.pdf. (Commenter's Exhibit 12)

[40] The Medicine Bow project's permit application estimates 40 hours of malfunction-related flaring per year Medicine Bow Fuel & Power, LLC PSD Permit Application, Dec. 31, 2007. Appendix B, p. 19. (Commenter's Exhibit 13)

[41] The application for the Power Holdings coal to SNG project in Illinois estimated upset emissions, when gases may be sent to the flare during malfunction without cleanup. The application contains malfunction evaluations at many points, and it attempts to identify the requirements for including malfunction emissions and specific actions for reducing them.
Moreover, the Power Holdings application modeled various malfunction scenarios using AERMOD, for both daytime and nighttime malfunction conditions, including:1) Unplanned shutdown of one methanation unit, sweet syngas to SNG flare for 60 minutes, 2) Unplanned shutdown of one Rectisol unit, sour syngas to SNG flare for 22 minutes (modeled as a 60 minute event); and 3) Unplanned shutdown of one WSA unit, acid gas to acid gas flare for 22 minutes (modeled as a 60 minute event). These scenarios represented the worst case malfunction events. Each malfunction scenario was setup for 23 hours of normal operations with one hour operating under one of the above listed malfunction condition. This operating situation was model as if it occurs every day during the 5 year period. This approach ensured that the highest 2nd high for each pollutant subject to PSD subject was identified.
PSD Construction Permit Application for the Southern Illinois Coal Gasification to Synthetic Natural Gas (SNG) Facility, Prepared for Power Holdings of Illinois, Southern Illinois Coal to SNG Facility, October 17, 2007 ("Power Holdings Permit Application"), Chapters 1 and 2. Specifically refer to Power Holdings Permit Application at 1-130 to 1-131. (Commenter's Exhibit 14)

To estimate SO_2 emissions during malfunctions, one would need the following information: piping and instrumentation diagrams showing how the flare is connected to specific processing equipment in the plant; the maximum potential flow and worst-case composition of gases from each safety vent venting to the flare and to atmosphere; and the flare design basis (worst-case flare release scenarios and maximum flow rate). With this information, one could complete a calculation of SO_2 and other emissions during malfunctions.

As set forth in USEPA Modeling Guidance, 40 CFR Part 51, Appendix W, air quality analysis (modeling) should consider emissions during normal operations. Appendix W expressly provides that malfunctions are not considered normal operations and need not be included in determining allowable emissions unless they are the result of poor maintenance or other preventable conditions. 40 CFR Part 51, Appendix W, 8.1.2.a Note a ("Malfunctions which may result in excess emissions are not considered to be a normal operating condition. They generally should not be considered in determining allowable emissions. However, if the excess emissions are the result of poor maintenance, careless operation, or other preventable conditions, it may be necessary to consider them in determining source impact."). Flaring as a result of emergency shutdowns of a cleanup train would be an uncommon occurrence, not normal operations. Consistent with Appendix W, the IEPA did not require CCG to model SO_2 emissions from flaring caused by a malfunction. The fact that others have chosen to conduct such modeling for certain projected malfunction scenarios does not show that the approach taken for the application for the TEC was inappropriate.

The permit contains enforceable hourly limits on SO_2 emissions from the flare. (Condition 4.1.6.b.). As already explained, the associated monitoring is sufficient to verify compliance with these limits. In addition, the permit requires root cause analyses for flaring incidents [Condition 4.1.5.3(d)].

Moreover, the comment claims that unplanned shutdowns of the gasification block will be common at the TEC due to the harsh processing conditions in the gasification block, and that these unplanned outages will lead to "unplanned releases" of emissions from an unspecified emission point within the gasification block. However, this is not directly supported by the material cited by the comment, as it addresses facilities using different gasification technology and systems.[42, 43, 44, 45] Moreover, as this material

[42] ***Operating Experience and Improvement Opportunities for Coal-Based IGCC Plants, Materials at High Temperatures*** **discusses operational issues at the Wabash River, Tampa Electric Company (TECO), Pinon Pine, Buggenum, and ELCOGAS IGCC plants. This discussion is not relevant to the TEC because none of those plants use Siemens gasifiers with a Rectisol® AGR unit and methanation unit to produce SNG. The gasifier and syngas conditioning train configuration and ultimate product manufactured from the syngas greatly influence the overall availability and reliability of a gasification block. Problems at TECO with corrosion in the lower gas temperature portions of the syngas train do not translate to similar problems at the TEC because the syngas composition and process equipment used in the syngas train are not the same. Dry gas filter corrosion and metallic candle filter blinding issues at Wabash will not occur at the TEC because the Siemens gasification system uses a wet raw syngas scrubbing process (refer to Section 2.2.3 of Volume 1 to the Application). Outages from problems with ASU integration at Buggenum will not occur at the TEC because the ASU and power block are not integrated. Finally, power block vibration and overheating at Buggenum is not relevant to the TEC because the combustion turbines at the TEC will be SNG/pipeline natural gas-fired and not syngas-fired.**

[43] ***World's Largest IGCC Celebrates 10th Anniversary, 25th Annual International Pittsburgh Coal Conference*** **focuses on the 10 year operating experience of the ELCOGAS IGCC plant which uses Udhe Prenflo gasifiers with coal and petcoke as feedstocks. This document does not contain a single instance of the terms "emissions," "releases," or "flare," and thus, does not support the comment's claims about excess flaring emissions during emergency shutdowns. The document also states that "the main problem relating to non-production hours within the gasification unit are the candle filters." The TEC syngas conditioning train will not use candle filters, and, overall the TEC gasification block shares very few similarities to the ELCOGAS plant.**

addresses "availability," that is the amount of time that a plant is able to operate and the capacity at which it is able to operate, as compared to periods when the plant is out of service for maintenance or cannot operate at its design capacity. Availability is a key metric for the operator of a plant for the amount of output or use that can be expected from the plant, as compared to theoretical operation at full capacity on a continuous basis. However, "lack of availability" is not synonymous with malfunctions or upsets by a plant. This depends on whether shutdowns can be scheduled and conducted in an orderly manner for both routine planned maintenance and other, emergency repairs and maintenance.

In this regard, as acknowledged by this comment, the application for the TEC includes provisions for up to 14 planned shutdowns of gasifiers and/or the gasification block each year. For this purpose, CCG indicates that the first and second year availability predicted by Siemens RAM analysis has been factored into its projections for the frequency and duration of gasification block startup and shutdown events. Therefore, the annual flare emission limits premised on these availability targets reasonably account for all flaring emissions expected to occur in the first and second years of operation. If excess flare emissions attributable to emergency shutdowns caused by a malfunction occur at the TEC, CCG is required to minimize emissions during these events to the greatest extent practicable in a manner consistent with safety and good air pollution control practices as specified in the SSM plan (Condition 4.1.5-2). These events may also trigger further remedial actions by CCG pursuant to the requirements for flare minimization plan (Condition 4.1.5-3).

Flare malfunction emission estimates represented in permit applications for other recent gasification projects are speculative and not supported by any engineering studies to justify the number and duration of specific malfunction events that are expected to occur at these new greenfield sites. Southeast Idaho Energy, Medicine Bow Fuel & Power, FutureGen, and Power Holdings are all unique, first-of-a-kind gasification facilities that combine existing technology in new and different ways to produce various products from syngas. For a greenfield site that has no similar facilities currently operating, estimates of the frequency and duration of specific malfunction events are mere conjectures on the part of the applicant. If these events

---

[44] ***Evaluation of Alternative IGCC Plant Designs for High Availability and Near Zero Emissions,*** **prepared by EPRI, discusses the historical reliability and availability data of solids-fed IGCC power plants and describes how this historical data can be used to improve the availability of new IGCCs plants through specific design enhancements. The references to air emissions in this document focus on NOx, SO_2, and CO_2 controls for conventional syngas-fired IGCC plants which are largely irrelevant for the SNG-fired power block at the TEC. The sulfur content of SNG is essentially zero, so none of the references to deeper sulfur removal to achieve lower SO_2 emissions from syngas-fired turbines at conventional IGCC plants are relevant. The discussions regarding NOx controls focus on whether or not SCR can be used on syngas-fired turbines due to concerns with ammonium bisulfate (ABS) formation in the SCR which could foul the catalyst. Again, due the very low sulfur content of SNG, ABS formation is not a concern and thus, CCG will operate SCR in conjunction with the combustion turbines at the TEC. The focus of the CO_2 emissions discussion is on the cost of CO_2 capture for conventional IGCC plants which do not already have AGR units equipped with CO_2 separation capabilities. Since the AGR unit at the TEC will generate a sequestration-ready CO_2 stream, the discussion about CO_2 capture in the EPRI study has no bearing on the TEC's gasification block.**

[45] **The reliability, availability and maintainability (RAM) analysis prepared by EPRI as a means to evaluate the outage rates of the combined cycle power block, ASU, gasification block, and acid gas removal/sulfur recovery units at nine existing conventional syngas-fired IGCC plants likely follows a similar methodology to the RAM analysis prepared by Siemens for the TEC. With a site-specific RAM analysis prepared to evaluate the unique design of the TEC's gasification block, the RAM analysis prepared by EPRI should not be relied upon to evaluate the types of unplanned outages that may occur at the TEC, rather the Siemens RAM analysis should be used for this purpose. Even if the EPRI analysis was consulted, many of the problems that caused unplanned outages at the IGCC plants studied are not transferrable to the TEC. Similar to the other IGCC plant availability and reliability studies cited by the comment, the unplanned outage statistics for the ELCOGAS plant referenced by the comment based a review of Exhibit 8 are also not transferable to the TEC.**

were truly "sudden, infrequent, and not reasonably preventable" failures of process equipment as the regulatory definition requires, then accurately estimating how often and for how long these events occur and calculating the associated air emissions that would result is not possible. To avoid such a speculative and potentially grossly inaccurate evaluation of air emissions, USEPA accommodates an alternative means for addressing emissions from malfunction events. Under the most commonly applied regulatory scheme for malfunction events, the source is required to quantify any excess emissions, report to the regulatory authority the circumstances surrounding the malfunction event, and provide an affirmative defense that the event was not caused by poor maintenance or careless operation for the agency to consider. This approach for handling malfunction events is reflected in the permit and will provide the IEPA with all of the necessary information to determine if the gasification block was operated in accordance with good air pollution control practice during any malfunction event that causes excess emissions from the flare.

15. As discussed in my other comments, the application does not provide data for the maximum SO_2 emissions of the flare during the worst-case hour. The calculations in the application are based on a large number of assumptions for planned events, which are either not disclosed at all, or are stated without support. These include: (1) the percent of the sulfur in raw syngas that is converted to SO_2 by combustion in the flare (stated as 98% without support); (2) the sulfur content of the coal gasified during the worst-case hour (not disclosed), or alternatively, the sulfur content of the raw syngas (not disclosed); (3) the coal throughput during the worst-case hour (not disclosed); and (4) the sulfur control achieved by operating procedures (stated as 60% without support). And these assumptions used for planned events may not be valid during malfunction events.

Based on the calculations I present above, the maximum hourly SO_2 emissions during the worst case event could range from 12,048 lb/hr if coal containing 5% sulfur were being gasified (instead of the 3.75% assumed in the calculations) to 20,080 lb/hr if coal containing 5% sulfur were gasified and the operating procedure assumed to reduce emissions by 60% could not be implemented due to emergency conditions.[46] Emissions could be even higher than either end of this range if the flare, supplemented with natural gas as proposed in the application, converted more than 98% of the sulfur to SO_2 or if even higher sulfur coal were gasified. The permit would allow either scenario.

The maximum amount of SO_2 that will be emitted by the flare during a cold plant startup of the gasification block forms the basis of the flare hourly SO_2 BACT limit, and the information used by CCG to develop this limit is clearly referenced in the application. The comment's hypothetical maximum hourly SO_2 emission calculations are not relevant in light of the flare SO_2 BACT limit in the permit and the requirement to continuously verify compliance with this limit using flare gas flow rate and sulfur content monitoring systems. If CCG were to feed coal with a sulfur content greater than 4.41% on dry basis at a rate more than 51.2 ton/hr to the gasifiers during a cold plant startup, it would run the risk of violating the flare hourly SO_2 limit. To ensure the sulfur flow rate to the flare does not exceed the value used in the derivation of the

[46] The lower end of the revised SO_2 flare emission range is 12,048 lb/hr ((9,036 lb/hr x 5%/3.75% = 12,048 lb/hr). The upper end of the revised SO_2 flare emission range is 20,080 lb/hr. ((9,036) x (5%/3.75%)/0.6 = 20,080 lb/hr.

SO_2 limit, CCG will have to appropriately manage the coal sulfur content and feed rate to the gasifiers while flaring raw syngas during a cold plant startup. Simply pointing out CCG could violate this limit by using coal that is not consistent with the design coal for the plant does not demonstrate that the flare SO_2 emissions are underestimated or the permit limits are inappropriate.

VOM EMISSIONS FROM FLARING

16. The flare will also emit volatile organic material (VOM) during routine and nonroutine operation. This arises from three sources: (1) pilot burner; (2) raw syngas; and (3) supplementary fuel. During routine operation, the flare will be equipped with a pilot that will continuously burn 0.34 mmBtu/hr of natural gas. During nonroutine operation, the waste gasification process gas itself will contain VOM. Supplemental natural gas fuel will be added to waste gas to aid combustion. These will all be combusted in the flare with an assumed 98% combustion efficiency.

VOM emissions were underestimated by improper use of an unrelated natural gas boiler emission factor for the flare pilot. The application projects flare VOM emissions of 0.008 ton/yr based on a flawed calculation procedure that assumes that combustion by the flare is similar to that of a natural gas fired boiler, and therefore a natural gas-fired boiler VOM emission factor is appropriate to estimate flare VOM emissions. [47] A natural gas-fired boiler combustion chamber is a highly controlled, contained environment. A flare has no combustion chamber and highly variable gas flow and flare gas composition, and is exposed to conditions, such as crosswinds, that are not present in a natural gas-fired boiler.

VOM emissions were also underestimated by the presumption that the assumed flare efficiency of 98% would be met at all times.[48] Flare combustion efficiency describes how much of a given pollutant is combusted relative to the total amount routed to the flare. If VOM is burned in a flare with a VOM combustion efficiency of 98% (as the application assumes), 2% of the VOM would be emitted, with the other 98% is converted into CO_2, water, and carbon monoxide.

It is reasonable to use an emission factor for natural gas combustion in a boiler, from Chapter 1.4 of AP-42, to calculate VOM emissions from supplemental pipeline natural gas/SNG combustion in the pilot burner of the flare at the TEC. This burner will be a small burner (340 scf/hr) that fires a set amount of fuel for which it is specifically designed. The burner must also be appropriately shielded to maintain a stable flame to fulfill its role as the pilot burner for the flare. As such, this burner is distinguishable from the main burner or flame of the flare for which combustion in the open air and for which wind has been identified as a factor that may affect the performance of the flare. Accordingly, the approach to the VOM emission calculations suggested by this comment is clearly not appropriate.

The comment also claims that the 98% destruction efficiency for VOM in the waste gas that is flared, which was used in the emission calculation for the flare, would not be

[47] Ap. v. 1, p. C-7.
[48] Ap., v. 1, pp. C-7 to C-14.

met at all times. However, the permit includes appropriate conditions to address the VOM destruction efficiency of the flare. This requirement for the efficiency of the flare is included in the permit (Condition 4.1.2(a)(v)). CCG must demonstrate compliance with this requirement by conducting the performance evaluations for visible emissions and heat content of waste process gas, (in accordance with the relevant requirements of 40 CFR 60.18 (Conditions 4.1.7-1(a) and (b)). CCG is also required to operate the flare in accordance with good air pollution control practices (Condition 3.6). Finally, CCG must to maintain a file containing the design destruction and removal efficiency of flare, with supporting documentation, for various pollutants including VOM (Condition 4.1.10-2(a)). The supporting documentation for the design efficiency for the flare would include the results of the above evaluation and information provided by the flare vendor that is relevant to the performance of the flare including any parametric operating ranges or specific work practice standards that are recommended. CCG must keep records of any visible emissions during each event when process gas is flared to demonstrate compliance with the requirements of 40 CFR 60.18(c)(1) (i.e., no visible emissions as determined by USEPA Method 22, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours) (Condition 4.1.10-2(b)(iv)). In addition, when syngas is flared and CCG does not expect to meet the requirements of 40 CFR 60.18, CCG must conduct visual observations of the flare flame stability to assess combustion efficiency (Condition 4.1.7-1(c)). These observations will work in conjunction with flare gas flow rate monitoring and periodic flare gas heating value and composition sampling to verify the flare is operated properly during each flaring event.

FUGITIVE PARTICULATE EMISSIONS

17. Fugitive particulate matter emissions from coal handling operations are also underestimated. CCG must demonstrate compliance with the 24-hour and annual PSD increments for PM_{10} and $PM_{2.5}$, the 24-hour PM_{10} NAAQS, and the 24-hour and annual $PM_{2.5}$ NAAQS. Among these, the most difficult to satisfy are the short- term, 24-hour standards. Among the various particulate matter emission sources, those that have the greatest impact are typically sources without control equipment, commonly referred to as fugitive sources. Thus, my evaluation of particulate emissions focuses on short-term PM_{10} and $PM_{2.5}$ emissions from various material handling operations. The modeling analyses must be based on the worst-case, maximum emissions of PM_{10} and $PM_{2.5}$ that could be emitted over this averaging period. The PM_{10} and $PM_{2.5}$ emissions included in the air quality modeling are not the worst-case, maximum emissions.

Fugitive emissions from "ground level sources," which are released at or near ground level, generally have the highest PM_{10} and $PM_{2.5}$ air quality impacts. The principal sources of fugitive material emissions at the TEC will be coal transfer points that are not controlled by baghouses (TP1-3) and the inactive coal storage pile (PILl). Emissions from other sources of fugitive emissions, such as the slag storage piles, are also underestimated due to the same issues discussed here, but are not revised as they have lesser impacts on air quality.

The emissions from these fugitive sources were calculated from empirical formulas developed by the USEPA. These formulas require site-specific inputs such as silt content,

moisture content, control efficiencies, and various meteorological variables. These input variables were consistently chosen to minimize emissions, which minimized the modeled air quality impacts.

Modeled emissions must be based on the maximum anticipated emissions, not the minimum, estimated in the application. 40 CFR Part 51, Appendix W, at Table 8-1 (identifying modeling emission input data for point sources as the "maximum allowable" or "federally enforceable" emission limit multiplied by the "actual or design capacity (whichever is greater)" or a "federally enforceable permit condition"); see pages C.45-46 of USEPA's *New Source Review Workshop Manual* (NSR Manual).[49] My comments discuss the errors in the principal sources of fugitive missions, focusing on short-term emissions. The same errors also exist for long-term annual emissions and other fugitive sources, but they are not explicitly discussed in my comments.

Contrary to claims made in the comment, the inputs to USEPA's AP-42 algorithms for quantifying fugitive PM emissions from material transfer and storage piles used by CCG to develop modeled emission rates for the 24-hr PM_{10} and $PM_{2.5}$ NAAQS and PSD Increment analyses are appropriate and were chosen to produce conservatively high estimates of the PM emissions expected to occur from the TEC. In many cases, the conservatism of the emissions estimates is expected to result in overestimates of modeled impacts and not underestimates as the comment suggests.

18. The plant would include three points where coal is transferred between conveyors and piles that are not controlled by dust collectors: (1) active storage dome or inactive pile conveyor loadout (TP1); (2) stackout conveyor #3 to inactive pile lowering well (TP2); and (3) inactive pile chain reclaimer to conveyor #4B (TP3).[50] As explained below, these emissions were significantly underestimated, by over a factor of ten, in the application. This affects the air quality modeling, as discussed in my other comments, as this emission data was used in the air quality impact analysis. The underestimate will never be discovered as the Draft Permit contains no emission limits for these points, no limits on the inputs to the emission calculations (*e.g.*, moisture content, silt content, vehicle miles traveled, coal throughput), nor any monitoring or other compliance provisions to measure these emissions. The Draft Permit would not set emission limits for these points in Condition 4.3.2(d). It also would not set emission limits that specifically apply to these units in Attachment 1, Table 2 of the permit. All of the inputs that are needed to calculate the emissions from these units can be readily measured or determined.

The particulate matter emissions from these three points were calculated in the application by multiplying an emission factor in pounds per ton (lb/ton) by the maximum actual annual operating rate of each point in tons per year (ton/yr). These uncontrolled emissions were then reduced using a control efficiency.

[49] USEPA, New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, October 1990 ("NSR Manual"); The NSR Manual has been used as a guidance document in conjunction with new source review workshops and training and as a guide for state and federal permitting officials with respect to PSD requirements and policy since it was drafted in 1990. Although it never progressed beyond a draft and is not a binding Agency regulation, the Environmental Appeals Board has looked to the NSR Manual as a statement of the USEPA's thinking on certain PSD issues. *See, e.g., In re ConocoPhillips Co.*, 13 E.A.D. 768, 772 (EAB 2008); *In re RockGen Energy Ctr.*, 8 E.A.D. *536, 542* n.10 (EAB 1999); *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 129 n.13 (EAB 1999).

[50] Ap., v. 1, Appx. C, Table C-9.4, p. C-38.

As noted by this comment, only three of the coal transfer points at the TEC would not be controlled by fabric filters or "baghouses." The three transfer point are: 1) the active storage dome or inactive pile conveyor loadout (TP1), 2) stackout conveyor #3 to inactive pile lowering well (TP2), and 3) inactive pile chain reclaimer to conveyor #4B (TP3). Using appropriate fugitive PM emission estimates, CCG has demonstrated that TEC is not expected to cause or contribute to air quality violations even under the worst-case (even potentially unrealistic) operating conditions that could conceivably occur at the TEC.

Beyond arguments related to underestimated modeled impacts, the comment also questions the underlying inputs used to generate the fugitive PM potential emissions estimates and the supposed lack of adequate PM emission limits and compliance monitoring provisions for these units in the permit. Annual PM, PM_{10}, and $PM_{2.5}$ emission limits for coal handling and storage PM units that include the PM emissions from the three coal handling transfer points not controlled by fabric filters are provided in Attachment 1 Table II of the permit, so the comment's statement that the "Draft Permit contains no limits at all for these sources" is not accurate. The comment also suggests that the permit does not contain any monitoring or other compliance provisions to quantify the fugitive PM emissions from these coal handling transfer points, which is clearly incorrect, in light of the numerous monitoring, recordkeeping, and reporting requirements included in Section 4.3 of the Permit.

Under certain circumstances, fugitive PM emissions from the coal transfer points at the TEC may be emitted over a relatively large area (as compared to stack type discharges) on an intermittent basis. The area over which emissions occur is dictated by the characteristic dimensions of the equipment used to convey the coal to the drop point and the height of the drop. Emissions would be intermittent because coal will not be continuously transferred at each of the affected points as is assumed in the NAAQS modeling.[51] For these coal transfers that occur intermittently, CCG assumed in the NAAQS modeling that emissions would be generated on a continuous basis, and thus, the modeled impacts should provide a conservatively high estimate for the actual impacts from the TEC. The magnitude of PM emissions from coal transfer points is influenced by the coal throughput, coal characteristics (primarily moisture content), and meteorological conditions occurring at the time the material is being transferred (i.e., wind speed and precipitation).

The draft permit addressed the fugitive PM emissions from TP1, TP2 and TP3 with the combined annual limits for PM emission from all coal handling and storage operations in Attachment 1 Table II. While these limits in conjunction with the operational monitoring, recordkeeping, and reporting requirements in the permit are sufficient to ensure that the TEC does not cause or contribute to air quality violations, in the issued permit, Table II includes limits for short-term PM emission for TP1, TP2 and TP3.

---

[51] **TP1 will only be active when coal deliveries are occurring. TP2 will only be active when coal is being routed from the truck loadout operation to the inactive pile which will only be required when the facility needs to build the inventory of coal in the inactive pile, and finally, TP3 will only be active when TEC is reclaiming material from the inactive pile rather than from the active pile storage dome. As an example of the intermittent nature of the coal handling operations at the TEC, TP1 could operate for as little as 2.5 hours/ day and still supply the necessary coal for the gasifiers based on the daily coal feed limit for the TEC (5,100 tons/day (Condition 4.1.5-1) and the maximum hourly rating of the conveyors that serve TP1 (2000 tons/hour, refer to Figure 2-3 of Volume 1 to the Application).**

These limits in conjunction with the daily plant-wide coal throughput limit in Condition 4.1.5-1, the feedstock management plan requirements in Condition 4.1.5-4, and the PM, PM_{10}, and $PM_{2.5}$ emissions recordkeeping requirements in Condition 4.3.10(g) will collectively ensure that the actual 24-hour average hourly PM_{10} and $PM_{2.5}$ emissions from the TEC will not exceed the emission rates used in the 24-hr modeling.

In addition to the BACT and modeling related compliance provisions added to the issued permit, TP1 to TP3 are also subject to the requirements of the recently updated NSPS for Coal Preparation and Processing Plants, 40 CFR 60 Subpart Y. NSPS are based on the best demonstrated technology (BDT) for controlling emissions from new sources, and typically establish minimum requirements for BACT limits and associated compliance procedures for sources in the affected source category. Given the timing of the update to this NSPS, the control technology review conducted by USEPA in support of this update reflects a sound approach to the control requirements for fugitive PM emissions sources involved with handling of coal. USEPA concluded that control of emissions of these operations was appropriately addressed by a 10% standard for opacity emissions. It did not choose to impose standards for the moisture content of coal in the updated NSPS. Limiting coal moisture content in the permit is not practical or necessary in light of the opacity limit and associated compliance provisions that apply to TP1 [Conditions 4.3.3-1(c), 4.3.7-1(b), 4.3.7-2(c), and 4.3.10(a)] and the fugitive dust control plan requirements that apply to TP2 and TP3 [Condition 4.3.3-1(d)]. Condition 4.2.3(i) has been added to the issued permit to impose a 10% opacity standard on TP2 and TP3 in addition to the 10% opacity limit for TP1 from NSPS Subpart Y. These requirements in conjunction with the operating and recordkeeping requirements for the dust suppressant systems used to control fugitive PM emissions from the coal transfer points [Conditions 4.3.5(b) and 4.3.10(b)(iii)-(v)] will reasonably ensure that actual PM emissions do not exceed the emission rates used in the air quality modeling.[52]

19. The emission factor for the three uncontrolled transfer points was determined using the following empirical formula for drop emissions in Chapter 13.2.4, Aggregate Handling and Storage Piles in USEPA's *Compilation of Air Pollutant Emission Factors* ("AP-42"), where k is a particle size multiplier, U is the mean wind speed, and M is the material moisture content. The values selected for the input variables U and M both significantly underestimated potential emissions from these transfer points. [53]

$$E\ (lb/ton) = k(0.0032)(U/5)^{1.3}/(M/2)^{1.4}$$

With respect to Mean Wind Speed (U), these transfer point emissions were estimated assuming a 5-year average wind speed of 8.1 miles per hour ("mph") as measured at the

[52] **It is also noteworthy that when evaluating control of fugitive PM emissions from coal transfer points, USEPA calculated baseline uncontrolled emission rates using the same AP-42 Chapter 13.2.4 algorithm used by CCG. Similar to the approach being used for the TEC, USEPA used a single average coal moisture content value to reflect all bituminous coal handling operations over the course of a year at all of the coal preparation plants represented by the model plant cost study. Memorandum, Christian Fellner, USEPA, to Coal Preparation NSPS Docket (EPA-HQ-OAR-2008-0260), Re: Model Plant Control Costing Estimates for Units Subject to the NSPS for Coal Preparation Plants (40 CFR Part 60 Subpart Y), April 2008. (Hereafter Fellner Memo). (Commenter's Exhibit 16.**

[53] Ap., v. 1, Appx. C, Table C-9.4, p. C-38 and AP-42, Chapter 13.2.4, p. 13.2.4-4; http://www.epa.gov/ttn/chief/ay42/ch13/final/c13s0202.pdf. (Commenter's Exhibit 15)

Springfield Capital Airport for the period 2003 to 2007[54]. The most recent values 5 year of data for 2006 to 2010 indicate the average wind speed at this site is 9.35 mph. This value is used in the revised emission calculations presented below.

Emissions from the three fugitive coal transfer points not controlled by baghouses were appropriately calculated. CCG used the most recent, readily available meteorological dataset from the IEPA (i.e., the 5-year data set from 2003-2007) at the time the PM_{10} and $PM_{2.5}$ modeling was initiated for the application and to establish the mean wind speed used in the coal transfer point PM emission calculations. This approach for selecting meteorological data applied to a regulatory air dispersion modeling analysis is consistent with USEPA guidance 40 CFR Part 51, Appendix W, Section 8.3.1.2 ("Appendix W"). Once the proposed data set was reviewed and approved by the IEPA through the January 2010 dispersion modeling protocol review process, this data was appropriately applied on a consistent basis for both modeling and emission calculations.[55] The comment suggests that a more recent meteorological dataset for the years of 2006-2010 should have been used; however, at the time modeling was initiated and fugitive emissions calculations were performed, surface characteristic data from the IEPA for 2008, 2009, and 2010 were not available for use in the AERMET meteorological processing. Further, the comment did not provide any evidence suggesting the somewhat higher mean annual wind speed resulting from the use of the 2006-10 data set is any more representative of what the mean annual wind speed may be once the TEC is operating.

The reason that USEPA recommends the use of a 5-year meteorological dataset for conducting dispersion modeling analyses is that a 5-year period should be sufficiently long to encompass the normal climatological variations that can affect the observed variables at a specific surface station, and thus, a 5-year dataset should also represent the range of modeled impacts that are expected to occur from a particular industrial site. By this logic, any 5-year dataset should have a mean wind speed that matches reasonably well with the long-term average wind speed over the period of record at the surface station. The relatively small difference between the 2003-2007 and 2006-2010 mean wind speeds of approximately 15 percent is not significant enough to warrant reconsideration of the potential emission calculations or the associated modeled emission rates for the TEC given the other conservative assumptions included in the calculations.

A key factor when considering the conservatism of the modeled emission rates for fugitive PM sources that rely on AP-42 algorithms with a wind speed component, is that actual wind speeds during the hours of the maximum impacts are not used in the calculations. As indicated in other comments, the maximum impacts from fugitive PM emission units modeled as volume or area sources in AERMOD are expected to occur at low wind speeds (typically below 3 knots) during stable atmospheric conditions which most commonly occur at night. Under these atmospheric conditions, the actual PM_{10}, and $PM_{2.5}$ emissions from these coal transfer points should be expected to be a

[54] Ap., v. 1, Appx. C, Table C-9.2, p. C-36.

[55] **Christian County Generation Taylorville, Illinois, *Class II Area PSD Air Quality Modeling Protocol*, Project 091801.0007, Trinity Consultants, Covington, Kentucky, January 2010.**

factor of about three lower than the modeled emission rate derived from the 2003-2007 mean wind speed (8.1 mph).[56] Assuming the mean wind speed is occurring throughout the year even during stable atmospheric conditions at night results in significant over prediction of the modeled impacts from fugitive PM units in AERMOD, and this assumption validates the conservatism of CCG's modeling for PM_{10} and $PM_{2.5}$.

20. With respect to Moisture Content (M), the emissions of these transfer point were estimated assuming material moisture content of 11%. The section of AP-42 that the application uses reports the moisture content of coal ranges from 2.8% to 11%. The application used the upper end of this range, which minimizes emissions. Further, a USEPA document that CCG relied on to estimate control efficiencies used a material moisture content in this very same equation of 1.85% for bituminous coal, proposed for the TEC.[57] The use of an upper-bound moisture content, which minimizes transfer emissions, is inconsistent with the requirement that emission estimates be based on the maximum potential emissions.

The AP-42 source document indicates that "[w]orst-case emissions from storage pile areas occur under dry, windy conditions. Worst-case emissions from material-handling operations may be calculated by substituting into the equation appropriate values for aggregate material moisture content and for anticipated wind speeds during the worst case averaging period, usually 24 hours."[58]

The Draft Permit does not contain any requirements for coal moisture content, a parameter that can be readily measured. Further, other sources indicate much lower moisture in Herrin coal. The U.S. Geological Survey ("USGS") COALQUAL database reports the as-received moisture content of 13 coal samples from the Illinois Herrin seam, the coal proposed for the TEC, ranges from 3.37% to 11.59%, average 6.48%. Elsewhere, the USGS reports between 1.2% and 22.2% moisture content for Herrin coal from 2,545 samples.[59] The worst-case potential emissions would occur when coal with the lowest moisture is handled, which is 1.2%. I conservatively used the lower end of the range of the COALQUAL database, 3.37%, which is well within the range of coal moisture reported in AP-42.

The coal moisture content is not based on the generic industry-wide data in AP-42 Table 13.2.4-1 for coal used at iron and steel production facilities, as the comment suggests, but rather are based on the Wood Mackenzie Study and other internal studies performed for the TEC to develop the preliminary design for the coal drying system. The studies performed to evaluate the coal properties from prospective local coal suppliers in the area immediately surrounding the TEC showed a range of coal moisture contents from 11 to 17 percent, so CCG actually chose the lowest representative coal moisture content and not the highest as the comment indicates.[60] Since site-specific data was available for the TEC, this data represents the "best data"

---

[56] For a 3.45 mph wind speed, $(U/5)^{1.3} = (3.45/5)^{1.3} = 0.62$, and for the mean wind speed used presented in Table C-9.2 of Appendix C to Volume 1 of the application, $(U/5)^{1.3} = (8.1/5)^{1.3} = 1.87$, which gives a ratio of 1.87/0.62 = 3.0.

[57] Fellner Memo, p. 4, bullet 2 (Material Moisture Content: 1.85% (for use in AP-42 fugitive emission factor equation)).

[58] AP-42, Chapter 13.2, p. 13.2.4-5.

[59] R.H. Affolter and JR. Hatch, Characterization of the Quality of Coals from the Illinois Basin, Chapter E of: Resource Assessment of the Springfield, Herrin, Danville, and Baker Coals in the Illinois Basin, U.S. Geological Survey Professional Paper 1625-D, p. E-31, Table *5;* available at http://pubs.usgs.gov/pp/p1625d/508/Chapter E 508.pdf. (Commenter's Exhibit 17)

[60] Illinois Commerce Commission Tenaska Facility Cost Report. Available at http://www.icc.illinois.gov/electricity/tenaska.aspx. (Also submitted as Commenter's Exhibit 52.)

and is appropriately used in emission calculations. AP-42 data is only typically preferred when site-specific data is not available.

USEPA's use of a coal moisture content of 1.85% for bituminous coal handling is not reflective of the range of coal moisture contents expected for the TEC. In addition, this moisture content is below the minimum end of the range for all types of coal handling described in AP-42 Table 13.2.4-1. Therefore, this factor was appropriately not relied upon in the PM emission calculations for the three coal transfer points at the TEC.

The comment's reference to USGS data for the moisture content of Herrin coal, with values significantly below the moisture content used by the TEC is not meaningful in light of the site-specific nature of the data for moisture content used by CCG. Herrin coal is found throughout the Illinois basin which covers much of Illinois and portions of Western Indiana and Western Kentucky. Simply pointing out the potentially wide variations in coal moisture content that may occur over this large area, and then arbitrarily choosing the low end of the range to use in revised PM emission calculations for the TEC is clearly not appropriate given the detailed studies that CCG has conducted for the specific coal suppliers expected to be used for the project which indicate the minimum coal moisture content will be 11%.

21. The emission factors in pounds per ton ("lb/ton") calculated from the above discussed empirical equation were next multiplied by the tons per year of material handled at each transfer point and reduced by an assumed control efficiency achieved through "wet suppression."[61] The emission calculations assumed control efficiencies of 50% for TP1 and TP2 (based on "water spray suppression")[62] and 85% for TP3 (based on "inherent chemical latency")[63]. These control efficiencies are not required as permit conditions and are excessive, given the type of source, required BACT controls, and the assumed very high moisture content. Further, the Draft Permit does not limit the tons per year of material handled at each transfer point, even though this is a critical input in the emission calculations.

Condition 4.3.2(d) of the Draft Permit identifies the control technology determination as "wet dust suppression." This term is distinguished in the Application from "chemical dust suppression," suggesting water is implied.[64] Condition 4.3.5(e) of the Draft Permit also indicates that conveyor transfer operations not controlled by filtration devices "shall be sprayed with water or a surfactant solution …" These controls are not adequate to achieve the control efficiencies assumed in the emission calculations.

Section 13.2.4-5 of AP-42, the section of AP-42 relied upon for these emission calculation, cautions that "[w]atering of the storage piles themselves typically has only a very temporary slight effect on total emissions." "Temporary" and "slight" effects do not constitute 50% to

[61] Ap., v. 1, Appx. C, Table C-9.3, p. C-37 (maximum operating rates) and Table C-9.5, p. C-39. See column labeled "emissions control."
[62] Ap., v. 1, p. 3-11 and Appx. C, p. C-39, Table C-9, note 1 (National Pollutant Inventory Emission Estimation Technique Manual for Mining Version 2.3, Environment Australia, December 5, 2001, Table 3).
[63] Ap., v. 1, Appx. C, p. C-39, Table C-9, note 1 (USEPA's Model Plant Control Cost Estimates for Units Subject to NSPS for Coal Preparation Plants, April 2008).
[64] *See* Ap., v. 1, Appx. C, p. C-1, Table C-1.1: "wet dust suppression" is indicated for TP1, TP2, and TP3 while "chemical dust suppression" is indicated for PIL1.

85% control over the worst-case 24-hour period modeled in the PSD increment and air quality impact analyses. AP-42 goes on to explain "A much more effective technique is to apply chemical agents (such as surfactants) that permit more extensive wetting. Continuous chemical treating of material loaded onto piles, coupled with water or treatment of roadways, can reduce total particulate emissions from aggregate storage operations by up to 90 percent."

Further, the Fellner memo, a document from USEPA's update of NSPS for Coal Preparation Plants in 2008, which was used by CCG to support the 85% control efficiency for TP-3 indicates that 85% control efficiency for a transfer point requires full enclosure and inherent chemical latency.[65] Chemical latency includes continuous application of a surfactant plus a binder. The permit record is silent on full enclosure of the subject transfer points and surfactants and binders for dust control. This USEPA analysis assumed that all new transfer points at coal handling facilities would include an enclosure, which was not even evaluated in the TEC BACT analysis.

The BACT analysis also did not conclude that continuous chemical treatment was BACT. Rather, it concluded there is not a technically feasible measurement method and only proposed wet suppression as a work practice standard in combination with a 10% opacity limit, consistent with the NSPS Subpart Y.[66] The record does not demonstrate equivalency, if any, between a 10% opacity standard and the modeled PM emissions. Further, this provides no basis at all for assuming 50% to 85% control, which requires the use of chemical suppressants and binders. The *Siemens Operations and Maintenance Operating Cost Assessment Report* does not include any costs for chemical suppressants for dust control, only costs for a "water wagon" which would be used 8 hours per day.[67]

Further, the Draft Permit does not require a 10% opacity limit. The only transfer point covered by NSPS Subpart Y is TP1.[68] No opacity limit at all is required for TP2 or TP3. The PM10/PM2.5 PSD increment and air quality analyses must be based on the maximum 24-hour emissions, not the short-term, best case emissions immediately after a watering event. Thus, a control efficiency of zero is warranted. However, to be conservative in favor of CCG, I have set the control efficiency equal to 50% for all transfer points in calculating revised emissions for modeling.

The comment claims that the water spray PM control efficiency applied for TP1 and TP2 (50%) and the chemical suppressant PM control efficiency for TP3 (85%) are excessive. The control efficiencies associated with TP1-3 are appropriate as each is obtained directly from widely used publications.[69] Furthermore, the comment

[65] Fellner Memo, p. 5, Table 3, p. 7, Table 4, p. 9, Table *5*, p. 11, Table 6.
[66] Ap., v. 1, p. 8-11.
[67] Siemens Operations and Maintenance Operating Cost Assessment Report, Exhibit 5.1, p. 17, http://www.icc.illinois.gov/downloads/public/en/Exhibit%205.1%20-%20Siemens%20Operations%20and%20Maintenance%20Operating%20Cost%20Assessment%20Report.pdf, (Commenter's Exhibit 18)
[68] Ap., v. 1, p. 4-12, Table 4-2.
[69] Control efficiency for wet dust suppression for TP1&2 based on National Pollutant Inventory (NPI) Emission Estimation Technique Manual for Mining Version 2.3, Environment Australia, December 5, 2001, Table 3. Estimated Control Factors for Various Mining Operations. Control efficiency for inherent chemical latency for TP3 taken from Long-term Coal Pile Load Out baseline control option in USEPA's Model Plant Control Cost Estimates for Units Subject to NSPS for Coal Preparation Plants, April 2008. These documents were used extensively for developing emission factors and control efficiencies for the recently finalized NSPS Subpart Y (Coal Preparation and Processing Plants) rule amendments.

contradicts what is considered to be an excessive versus appropriate control efficiency for TP1 and TP2 by stating that the control efficiencies used in the application are excessive and unfounded, but in turn use the same control efficiencies in their revised calculations. TP3 is the transfer from the inactive pile reclaimer to the conveyor. Since the inactive pile is controlled by chemical surfactants, which includes a binder, the control efficiency is appropriately higher for TP3 than the other transfer points, as indicated in the Fellner Memo.

The comment's reference to USEPA's statements regarding the effectiveness of water sprays for controlling fugitive PM emissions from storage piles is not relevant to the control efficiency assumed for water sprays applied to coal transfer points. Pursuant to Condition 4.3.10(a)(v), the water spray system for the coal transfer points are required to be operated whenever coal is being transferred, and CCG is required to verify on a monthly basis that water spray systems are operating in accordance with the manufacturer's specifications. These permit requirements will ensure that at least 50% control is achieved in accordance with the manufacturer's design fugitive PM control efficiency for the water spray system. In addition to the National Pollutant Inventory (NPI) Emission Estimation Technique Manual for Mining that references a 50% control effectiveness for water sprays applied to material handling transfer points, the Western Regional Air Partnership's (WRAP) Fugitive Dust Handbook also cites a control effectiveness range of 50 to 90% for water sprays applied to material handling sources.[70] Finally, the following statements by USEPA in the section of AP-42 for Sand and Gravel Processing (Chapter 11.19.1, page 5) indicate that control efficiencies in excess of 50 percent can be achieved for material handling with water sprays:

> **Wet suppression techniques include application of water, chemicals and/or foam, usually at crusher or conveyor feed and/or discharge points. Such spray systems at transfer points and on material handling operations have been estimated to reduce emissions 70 to 95 percent. Spray systems can also reduce loading and wind erosion emissions from storage piles of various materials by 80 to 90 percent. Control efficiencies depend upon local climatic conditions, source properties and duration of control effectiveness. Wet suppression has a carryover effect downstream of the point of application of water or other wetting agents, as long as the surface moisture content is high enough to cause the fines to adhere to the larger rock particles.**

The comment is incorrect that the use of an 85% control credit (from the Fellner memo) would require enclosure of TP3. The most representative type of operation described in the Fellner memo is "long-term coal pile load out," Thus, the applicable control efficiency for inherent chemical latency is provided in Table 6 for Model Plant D (a 200 ton/hr bituminous coal preparation plant located at an electric utility power plant) and not any of the other tables in the Fellner memo. The control efficiency for transfer points associated with long-term coal pile load out in the Fellner memo is further supported by USEPA's statements in AP-42 Chapter 13.2.4 that "continuous

[70] **Countess Environmental, *WRAP Fugitive Dust Handbook*, September 7, 2006.**

chemical treating of material loaded onto piles, coupled with watering or treatment of roadways, can reduce total particulate emissions from aggregate storage operations by up to 90 percent."

The BACT determination that wet dust suppression would be applied to TP1-3 was intended to encompass the water sprays applied to TP1 and TP2 and the chemical suppressants (single chemical suppressant solution containing a surfactant and a binder) applied to TP3. Per Condition 4.3.2(d), wet dust suppression is required on all material handling equipment not controlled by a baghouse or a vent filter. The use of wet dust suppression will be ensured by the requirement to implement a fugitive coal dust emissions control plan that specifies the approved control measures used to minimize fugitive dust for TP2 and TP3 and a requirement to limit opacity to 10% for TP1. Furthermore, TP3 will have controls beyond wet dust suppression since the inactive pile will utilize chemical surfactants that include a binder which will provide an inherent chemical latency for transfer at TP3. To make this clear, Condition 4.3.2(d)(i) in the issued permit (Condition 4.3.2(d) in the Draft Permit) specifically requires water spray for TP1 and TP2 and application of chemical dust suppressant for TP3. An explicit BACT limit in terms of opacity (10%) is also present for these units in new Condition 4.3.2(d)(ii) in the issued permit.

As discussed previously, an opacity limit is set as BACT for TP1, TP-2 and TP-3, rather than a mass limit for particulate emissions, since compliance with an opacity limit may be readily determined by direct observation. However, CCG is also required to demonstrate that the selected control measures are achieving the required levels of emissions on an ongoing basis [Condition 4.3.10(a) and (b)].

The Siemens cost estimates referenced by the comment are part of a preliminary cost assessment report. They should not be considered to provide a comprehensive list for all operating expenses that will be incurred at the TEC, including costs for relatively inexpensive aspects of the plant, such dust suppression systems.

Finally, the PM_{10} and $PM_{2.5}$ modeled emission rates are not based on "best case emissions following a watering event" for two primary reasons. First, the moisture content used in the PM emission calculations is based on the lowest moisture content for the coal supply for the plant, not the highest as claimed. Second, water and chemical surfactant sprays at TP1-3 will be applied on a continuous basis, whenever fugitive dust emissions could be generated, and not based on some periodic schedule as the comment indicated by the use of the term "watering event."

22. I recalculated the emissions of these transfer points, using IEPA's emission verification spreadsheet, making the changes discussed above. I reduced the moisture content from 11% to 3.37%, increased the wind speed from 8.1 mph to 9.35 mph, and reduced the control efficiency to 50%, based on the absence of any enforceable permit conditions. These changes increase emissions by factors of 13 (TP1 and TP2) to 42 (TP3).[71]

[71] The revised emission calculations were provided as part of Commenter's Exhibit 19.

As discussed in response to specific comments, this commenter has not identified flaws in the emission data provided by CCG for the subject emission units. As such, the revised emission data for these units prepared by this commenter is neither reasonable nor credible. The precipitation factor was inadvertently applied to the short-term $PM_{2.5}$ emission rate in the IEPA verification spreadsheet. The precipitation factor was not applied in CCG emission calculations as shown in Tables C-12.1 and C-12.2 of Appendix C to Volume 1 of the Application. Therefore, the modeled short-term $PM_{2.5}$ emission rate did not include the precipitation factor in the NAAQS analysis. Regardless of the inadvertent use in the IEPA verification spreadsheet, the NAAQS analysis results presented in the Application and the Project Summary demonstrate that TEC will not cause or contribute to a $PM_{2.5}$ NAAQS violation.

23. The particulate emissions of the Inactive Coal Storage Pile Emissions (PIL1) were also underestimated. The plant will include two coal storage piles: (1) an active pile located inside a dome that is controlled by a baghouse, and (2) an inactive storage pile that is in the open. This comment addresses the emission calculations for the inactive storage pile. At the inactive pile, a reclaimer will transfer coal from the pile to a conveyor for transport to the crush surge bin. Mobile equipment (dozers/loaders) will keep the inactive storage pile compacted and move coal as needed to the reclaimer.[72] As addressed in the application, there are three sources of particulate emissions from the inactive storage pile: (1) wind erosion; (2) material transfer by dozers and/or front end loaders, and (3) mobile equipment traffic on unpaved surfaces in the storage yard. As discussed in my comments, the emissions from all three of these sources were underestimated.[73]

In actual practice, the role of the inactive pile will be to provide a reserve supply of coal for the plant, beyond the 30-day capacity of the storage dome for the active coal pile. If coal deliveries are occurring on a regular basis, the active storage pile/storage dome should be able to handle all the coal for the plant without any routine loading or reclaiming of coal at the inactive pile. The inactive coal pile will only be brought into service when there is an extended interruption in the regular delivery of coal and as needed for the turnover of the pile in accordance with good practices. CCG did not account for the intermittent operation of the inactive pile in its emission calculations. The emission calculations and the modeling assumed that the inactive pile would operate on a continuous basis to handle all of the coal for the plant. CCG also assumed that the active storage dome would operate on a continuous basis. At a fundamental level, this "double counting" of emissions from the coal piles means the modeled impacts were not underestimated. This double counting was overlooked in the comment, which focused on the individual inputs to the emission calculations for the inactive storage pile. As will be explained in response to detailed comments on those inputs, CCG reasonably calculated the emissions of the inactive coal storage.

24. The emissions of the inactive pile are underestimated due to the approach to wind erosion. Dust or particulate is generated by wind erosion of open coal storage piles. The application estimated these emissions using emission factors in pounds per day per acre

[72] Ap., vol. l, p. 2-4.
[73] The revised emission calculations were provided as part of Commenter's Exhibit 19.

("lb/day/acre"),[74] calculated using an empirical equation from a USEPA document, *Control of Open Fugitive Dust Sources*, Section 13.2.4.[75] A separate equation was used for short-term and long-term (annual) emissions. This emission factor in lb/day/acre was then converted into pounds per hour (lb/hr) by multiplying it by surface area of the pile (600 ft x 600 ft x 45 ft high or 9.74 acres) and converting the units from days to hours.[76]

The following comments discuss only the short-term emission calculations as these were used in the air quality modeling. However, the same underestimates discussed below for the short-term emissions are also present in the annual emission calculations. The emission factor for short-term wind erosion emissions was estimated from the following empirical formula, where k is a particle size multiplier, s is the silt content of the coal in percent, and f is the percent of the time the unobstructed wind speed exceeds 12 mph at the mean pile height. The application's choices for the silt content and wind speed variables underestimate wind erosion emissions.

$$E_{ST} \text{ (lb/day/acre)} = k \times 1.7 \times (s/1.5) \times (f/15)$$

Before discussing the specific inputs used for the short-term emission factor, it is appropriate to consider the basis of the acreage used to determine the emission rate from wind erosion at the inactive pile. For the short-term and annual[77] potential emission estimates and associated modeled emission rates, CCG assumed that the exposed area of the inactive pile will be at a maximum for all hours of the year, and that a constant supply of "fresh" dust is available to be blown from the pile on a continuous basis. The only way that this would actually occur would be if CCG was constantly loading and reclaiming coal from various locations on the pile at maximum rates, that is, using this pile as an active coal pile, and not an inactive pile. In addition, the actual size of the pile (and associated exposed surface area) would likely be much less than that associated with a 60 day supply of coal, as was assumed in the emission calculations and modeling. Therefore, the hourly wind erosion emission rates considered in the modeling should never be exceeded in practice if CCG applies chemical surfactants to coal as it is loaded onto the inactive pile, as required by the permit [Condition 4.3.2(d)].

25. The emissions of the inactive pile are underestimated due to the approach to silt content. The inactive storage pile wind erosion emissions included in the modeling assumed an average silt content of 5%, which is consistent with the average silt content reported in AP-42, Chapter 13.2, Table 13.2.4-1, for coal (4.6%). However, modeled emissions must be based on worst-case, maximum emissions. The higher the silt content, the higher the

[74] Ap.,v.1,Appx. C, p. C-45.
[75] USEPA, Control of Open Fugitive Dust Sources, EPA-450/3-88-008, September 1988; available at: http://www.primavoce.org/downloads/Control Of Fugitive Dust Sources.zip. (Commenter's Exhibit 20)
[76] Ap., v. 1, Appx. C, p. C-46 and IEPA Spreadsheet, Tab: Fugitives, cell U17.
[77] **Annual particulate emissions from wind erosion at the inactive pile were estimated from the following empirical formula, which accounts for days on which precipitation occurs, as is relevant for a determination of annual emissions. The precipitation factor is not applied to the short-term potential emission calculations, because potential emissions estimates are intended to represent the worst-case conditions under which emissions may occur, and windblown dust emissions are negligible during precipitation events.**
E_{ANNUAL} (lb/day/acre) = k × 1.7 × (s/1.5) × (f/15) × [(365 - p)/235]

emissions. The AP-42 reported silt content of coal ranges up to 7.7%.[78] Thus, 7.7% is used in the revised emission calculations.

The comment suggests that the highest silt content provided in AP-42 for coal storage at iron and steel foundries must be considered representative for the TEC rather than the average value for this industry which it claims is the basis for the silt content used in CCG's calculations. CCG did not rely on AP-42 silt content factors from the metallurgical industry as the comment suggests. This is because the plant will not use metallurgical coal, but rather bituminous coal as used at coal-fired power plants. Accordingly, considering the available industry classifications in Table 13.2.4-1, in AP-42, CCG appropriately used data for "coal-fired power plants." For coal-fired power plants, Table 13.2.4-1 provides a range of 0.6 percent to 4.8 percent silt (average of 2.2 percent based on 60 samples). The 60 samples are the most samples for any industrial category in AP-42. CCG conservatively used a silt content of 5 percent which is actually higher than the maximum for this category.

26. The emissions of the inactive pile are underestimated due to the approach to wind speed. The empirical wind erosion equation used to estimate short-term emissions depends upon the percent of the time the unobstructed wind speed exceeds 15 mph at the mean pile height (f factor). The calculations used in the air dispersion modeling assumed 26.66% based on 5 years of data for the period 2003 to 2007 from the Springfield Capital Airport. The most recent 5 years of data for 2006 to 2010 indicates the f factor is higher, 27.7%. This updated value is used in my revised emission calculations.

The wind speed variable (f) in the wind erosion emission factor algorithm is based on a threshold of 12 mph. Without actual calculations to support the wind speed frequency of 27.7% presented by this comment, it is not possible to evaluate whether the adjustment was incorrectly based on 15 mph or actually used 12 mph[79] and wind speed in the 2006 to 2010 dataset differs slightly from the 2003 to 2007 data set used by CCG. Even if 27.7% is correct and the reference to a wind speed threshold of 15 mph is a mistake, this small difference in this factor would only increase the emissions from wind erosion by about 4 percent. This is negligible compared to the total emissions from the inactive pile and would not affect the conclusions of the air quality analyses.

27. The emissions of the inactive pile are underestimated due to the approach to the efficiency of control measures. The emissions calculated using the relevant empirical equation were reduced by 90% based on "spraying chemical suppressants."[80] The Fellner memo, which was cited in support of this.[81] explains that chemical suppression means the application of a surfactant plus a binder, as opposed to just a surfactant. A surfactant controls dust from application until the coal is dry while the use of a binder in combination with a surfactant binds the dust particles until the coal is crushed or worked.[82]

[78] AP-42, Table 13.2.4-1.
[79] In one place, this comment indicates that this value is 15 mph; in another, it indicates that this value is 12 mph.
[80] Ap., v. 1, Appx. C, Table C-12.3, p. C-4, note 2.
[81] Fellner Memo, Ap., v. 1, Appx. C, Table C-12.3, p. C-46.
[82] Fellner Memo, p. 2.

The BACT analysis did not even evaluate chemical suppression for the inactive storage pile, but rather only "wet dust suppression and pile compaction as work practice standards."[83] Condition 4.3.2(d) of the Draft Permit would only require "wet dust suppression" but does not require any control efficiency whatsoever. "Wet dust suppression" is not defined in the Draft Permit or anywhere in the Permit record and can include less than continuous application of water, which would result in no reduction in emissions. The Draft Permit does not impose any emission limits at all for any operations at the inactive storage pile, not even on the key variables in the equations used to calculate these emissions, *e.g.*, silt content, pile area, vehicle miles traveled.[84]

As previously explained for transfer emissions, the section of AP-42 that addresses storage piles cautions that "[w]atering of the storage piles themselves typically has only a very temporary slight effect on total emissions." "Temporary" and "slight" effects do not constitute 90% control over the worst-case 24-hour period. A chemical suppressant coupled with a binder is required to achieve such high control efficiencies.

The AP-42 storage pile section goes on to explain: "A much more effective technique is to apply chemical agents (such as surfactants) that permit more extensive wetting. Continuous chemical treating of material loaded onto piles, coupled with water or treatment of roadways, can reduce total particulate emissions from aggregate storage operations by up to 90 percent."[85]

Thus, the Fellner memo does not support use of 90% control of wind erosion emissions from the inactive storage pile. The air quality$_5$ analysis must be based on the maximum 24-hour emissions, not the short-term, best case emissions immediately after a watering event. Thus, I have set the control efficiencies equal to 50%.

This comment misinterprets the information in the Fellner memo regarding the use of chemical dust suppressants. As discussed in the Fellner memo, the scope of a chemical dust suppressant system for which model plant costs were estimated includes all headers, nozzles, chemical feed system, bulk chemical storage tank, and the program logic control system to control the amount of the suppressant applied. The latency of the suppressant or its ability to remain on the surface of the coal is the property that determines the control effectiveness achieved by the suppressant. USEPA specifically stated when it referenced control efficiencies for chemical dust suppressants in the model plant studies, it is referring to the application of a single suppressant material that includes a surfactant plus a binder and not application of two separate materials as the comment suggests. One of the dust suppressant manufacturers that USEPA consulted during the update of the NSPS Subpart Y was AKJ Industries.[86] The product decision tree portion of the AKJ website clearly indicates that chemical dust suppressants for process dust control at coal handling facilities are purchased as a single solution.[87] To document that a suppressant with both a surfactant and a binder

[83] Ap., v. l, p. 8-18.
[84] See Condition 4.3.2.d, Attach. 1, Table II.
[85] AP-42, p. 13.2.4-5.
[86] **Memo from Jeff Cole, RTI International to Christian Fellner, EPA OAQPS, Contact Summaries with Equipment Vendors Used for Obtaining Costing Information, February 22, 2008, Subpart Y NSPS Docket, EPA-HQ-OAR-2008-0260-0009**
[87] **http://www.akjindustries.com/decisionTree.php**

will be purchased and applied to the inactive pile at the TEC, the fugitive dust control plan required by the NSPS Subpart Y must include a Occupational Safety and Health Administration (OSHA)-compliant material safety data sheet (MSDS), and CCG must consider and document in the plan the site-specific impacts associated with the use of such chemical dust suppressants [40 CFR 60.254(c)(6) and Condition 4.3.3-1(d)].

Contrary to the claim made in the comment, the permit does contain emission limits that address particulate emissions from the inactive coal pile. The combined coal handling and storage annual PM, PM_{10}, and $PM_{2.5}$ emission limits in Attachment 1 Table II include emissions from the inactive pile. While these limits in conjunction with the other monitoring, recordkeeping, and reporting requirements in the permit should be sufficient to ensure that the TEC does not cause or contribute to an air quality violation, in the issued permit, additional short-term limits specifically for the inactive pile have been added to Attachment 1 Table II. These emission limits in conjunction with the other inspection, recordkeeping, and reporting requirements in the permit will collectively ensure that the particulate emissions from the TEC will not exceed the emissions rates used in the air quality modeling.

As mentioned previously for coal transfer points, the term wet dust suppression is a generic term that covers both water sprays and chemical suppressant sprays. To clarify that BACT for the inactive pile is chemical dust suppression and not water sprays, in the issued permit, Condition 4.3.2(d) of the permit indicates that wet dust suppression means water sprays for TP1 and TP2 and application of chemical dust suppressant for TP3. While the permit does not impose a specific limit on the control effectiveness of the chemical suppressant sprays for the inactive pile since measurement methodology is not available to directly measure this, Condition 4.3.10(b)(v) requires recordkeeping to demonstrate the sufficiency of the control practices that have been developed to comply with permit requirements and to further demonstrate that those practices are being implemented. In this regard, the BACT determination for the inactive storage pile required that chemical dust suppressants would be sprayed on the pile to achieve 90 percent nominal control efficiency. As discussed in the Project Summary, the IEPA also indicates that given the size of the plant property and location in an agricultural area, the BACT determination need not require storage of all bulk dry materials in buildings or silos. This is consistent with other PSD permits issued by the IEPA that provide for outdoor storage piles.

28. I recalculated the emissions for the inactive pile for wind erosion , using IEPA's emission verification spreadsheet[88], making the changes discussed above. I increased the silt content from 5% to 7.7%, increased the f factor from 26.66% to 27.7%, and reduced the control efficiency from 90% to 50%. These changes increase emissions by factors of 8 to 11.

As discussed in response to specific comments, this comment has not identified flaws in the emission data provided by CCG for the subject emission units. As such, the revised

[88] I note that the IEPA verification spreadsheet contains an error for short-term $PM_{2.5}$ emissions. It used the long term annual equation for wind erosion emissions (in cell AH17). This equation reduces emissions based on the number of days with greater than 0.01 inches of precipitation per year, to estimate short-term emissions in cell AQ17, rather than the equation for short-term emissions, without this term. I corrected this error.

emission data for these units contained in this comment is neither reasonable nor credible.

Two errors in the IEPA verification spreadsheet were identified in the comment relating to the PM_{10} and $PM_{2.5}$ emission rates for pile maintenance at the inactive pile. These errors were not in the Application as the correct PM_{10} particle size multiplier for the PM_{10} emissions from pile maintenance at the inactive coal pile was used in Table C-12.8 of Appendix C in Volume 1 of the Application, and the correct PM_{10} emission rate was used in the modeling for this source. The mistake in the IEPA's verification spreadsheet does not change the accuracy of the PM_{10} NAAQS analysis results submitted by CCG.

Table C-12.8 of Appendix C to Volume 1 of the Application includes the hourly and annual $PM_{2.5}$ emission rates for pile maintenance at the inactive pile that were included in the modeling. The failure to include these emission rates in the IEPA verification spreadsheet does not affect the accuracy of the modeling results submitted by CCG.

None of these identified errors in the IEPA's verification spreadsheet resulted in material impacts on the modeling results.

29. Emissions from maintenance of the inactive storage pile, Transfer Point Emissions (PILl), were also underestimated. Pile maintenance, moving material onto the pile to maintain its shape for efficient reclaiming, generates emissions from drop or transfer operations, as discussed below. The inactive storage pile maintenance emissions were calculated in the same manner, using the same input assumptions, as previously described for transfer points TP1 to TP3[89], and thus contain the same errors discussed in my previous comments. I have recalculated storage pile transfer emissions, changing mean wind speed ("U") from 8.1 mph to 9.35 mph; the moisture content ("M") from 11% to 3.37%; and the control efficiency from 90% to 50%.[90] These changes increased emissions by a factor of more than 30.

Similar to the conservative assumptions used to estimate wind erosion emissions from the inactive storage pile, CCG calculated emissions from pile maintenance using maximum hourly and annual coal rates for the plant, with all coal handled by the inactive pile rather than active pile and that the dozers and loaders will handle all of the material loaded onto the inactive pile. Since the fugitive PM emissions from reclaiming the material from the inactive pile are already accounted for under TP3, dozers and loaders' fugitive PM emissions for pile maintenance are only intended to address to emissions from dropping coal onto the pile to maintain its shape. Therefore, assuming that all of the coal loaded onto the pile is handled by dozers and loaders used for pile maintenance is conservative and results in mass emission rates that would be much higher than those actually experienced regardless of the assumptions regarding coal moisture content and wind speed that were assumed in establishing the PM emission factor.

[89] Ap., v. 1, Appx. C, Table C-12.8, p. C-50.

[90] In addition to these corrections, the IEPA spreadsheet contains the following two errors, which were also corrected: (1) The PM_{10} particulate multiplier in cell C17 was incorrectly reported as 0.5. I changed it to 0.35. (2) The spreadsheet did not include any calculations for $PM_{2.5}$ emissions for this source. I added them.

Accordingly, as already discussed with respect to wind erosion, the emission calculations for maintenance activity on the inactive pile are reasonable and do not require revisions. The data used for mean wind speed and moisture content are appropriate. A control efficiency of 90% for use of chemical suppressants (which include a binder) is documented in both the NPI Emission Estimation Technique Manual for miscellaneous transfer and conveying (90 percent control efficiency is assigned for water sprays with chemicals) and the Fellner memo, which indicates 90% control efficiency for inactive pile load in/load out with chemical suppresants.

30. PM emissions are generated by dozers and loaders travelling in the unpaved storage yard area associated with the inactive storage pile. The emission factors in pounds per vehicle mile traveled ("lb/VMT") were estimated using the unpaved haul road equation from AP-42. A separate equation was used for short-term and long-term (annual) emissions. These emission factors were multiplied by an estimate of the miles travelled to calculate emissions in pounds per hour ("lb/hr") and tons per year ("ton/yr").[91] The following comments discuss only the short-term emission calculations as these were used in the air dispersion modeling. However, the same underestimates discussed below for the short-term emissions are also present in the annual emission calculations.

The emission factor for short-term unpaved storage yard emissions was estimated from the following empirical formula, where E is an emission factor in pounds per vehicle mile traveled, S is the surface material silt content in percent, W is the mean vehicle weight in tons, and the exponents a and b are size-specific constants from AP-42, Table 13.2.2-2.[92] The resulting factors were multiplied by vehicle miles traveled and a control efficiency to determine emissions in lb/hr and ton/yr. These emissions were underestimated due to the choices for silt content and control efficiency, as discussed below.

$$E = k \times (S/12)^a \times (W/3)^b$$

The daily vehicle miles travelled assumed for pile maintenance is equivalent to a dozer or loader travelling around the maximum perimeter of the inactive pile more than 60 times per day. This travel distance is much higher than the distance will be needed to maintain the inactive pile. This conservative assumption in conjunction with the other conservative assumptions used to quantify PM emissions from wind erosion and coal transfers associated with pile maintenance result in overestimates of these emissions and modeled impacts.

31. The emissions from maintenance activities are underestimated due to the approach to silt. The unpaved storage yard emissions assumed an average surface material silt content of 4.9%, based on the lower end of the range (4.9% - 5.3%)[93] in AP-42, Chapter 13.2.2, for unpaved plant roads at western coal mines. The same AP-42 table reports silt content for other unpaved roads at western coal mines, including haul roads to/from the pit (2.8-18%),

[91] Ap., v. 1, Appx. C, pp. C-47 to C-49, Table C-12 and IEPA Spreadsheet, Tab: Fugitives, Cell U17.
[92] Ap., v. 1, Appx. C, p. C-47, Table C-12 and AP-42, Chapter 13.2.2, Equation (la), p. 13.2.2-4.
[93] Ap., v. 1, Appx. C, p. C-47, Table C-12 and AP-42, Chapter 13.2.2, Table 13.2.2-1.

scraper route (7.2-25%), and freshly graded haul roads (18-29%).[94] Modeled emissions must be based on worst-case, maximum emissions. The silt content of coal reported in AP-42, Chapter 13.2.2, ranges up to 29%.[95] Further, an unpaved storage yard is not similar to a plant road, but rather more like haul roads to and from the pit or freshly graded haul roads as material spills from dozers/loaders and covers the yard.

The permit record contains no basis for selecting the lower end of the plant road silt content range. The Draft Permit contains no limit on silt content of the storage yard or any requirement to test the silt content, a measurement that is easy to make. Thus, I use the upper end of the reported range of 29%. This change alone is sufficient to increase hourly storage yard PM_{10} emissions from 0.29 lb/hr to 1.45 lb/hr and hourly storage yard $PM_{2.5}$ emissions from 0.0292 lb/hr to 0.14 lb/hr or by a factor of five.

The comment suggests that it would be appropriate to use the highest silt content provided in AP-42 Chapter 13.2.2 for freshly graded haul roads at western surface coal mines (29%) rather than the average AP-42 silt content for plant haul roads at western surface mines as used by CCG. Freshly graded haul roads have higher silt loading than haul roads to/from a pit or plant roads because the grader refreshes the road surface with previously unexposed aggregate that could then generate PM emissions from entrainment of road surface silt in the vehicle wake of equipment travelling on these roads. Due to the limited use of inactive pile and associated limited traffic by dozers/loaders, grading the yard area will not be necessary, and as such, the yard area will more closely resemble an unpaved plant road for which grading and scraping are not typically required. The low end of the plant haul road silt content range for western surface coal mining was selected because the silt content of the unpaved yard area for the inactive pile is expected to be lower than roads at a western coal mine. The weight of the equipment travelling on western mine roads is much higher than the dozers/loaders at the TEC due to the much larger size of the equipment. These larger vehicles have a higher tendency to pulverize the aggregate used for the road surface which tends to create a higher fraction of small silt particles on the road surface. The lighter equipment used at the TEC will not lead to the same degree of road surface crushing, and therefore, it is appropriate and conservative to use the low end of the range for western mines.

32. The emissions from maintenance activities are underestimated due to the approach to the efficiency of control measures. The unpaved storage yard emission calculations assume a control efficiency of 90%, based on spraying chemical suppressant as reported in the Fellner memo, as previously discussed for transfer and wind erosion emissions. This control efficiency only applies when both a chemical suppressant and a binder are applied continuously. The Draft Permit would only requires wet dust suppression, which, as explained in previous comments, would not provide any particulate control over the subject worst-case, 24-hour averaging period, unless it is continuous and includes both surfactant and binder. The Draft Permit does not require any of these conditions. Lowering the control efficiency from 90% to 50% increases storage yard PM_{10} emissions from 0.29 lb/hr to 1.45 lb/hr and $PM_{2.5}$ emissions from 0.0292 lb/hr to 0.146 lb/hr, or by a factor of five.

[94] AP-42, Chapter 13.2.2, Table 13.2.2-1.
[95] AP-42, Chapter 13.2.2, Table 13.2.2-1.

The comment claims 50% control efficiency should be used in the emission calculations because the BACT conditions in the Draft Permit only require control with wet dust suppression. However, Condition 4.11 of the permit does not require that only wet dust suppression be used to control vehicle emissions on the inactive storage yard. Condition 4.11 also requires a written operating program (program to include application rate, type of additives, frequency of application, etc.), 10% opacity limit, particulate matter emission limits, and associated recordkeeping requirements. The combination of these requirements will ensure the proper control of the inactive pile storage yard by chemical suppressants.

33. The emission calculations for the inactive storage pile do not include the emissions from using dozer/loaders to move coal from the pile to the reclaim conveyor.[96] These emissions are similar to those estimated for bulldozing at western surface coal mines[97] and are substantial.

This comment reflects a flawed review of CCG's actual emission calculations for the inactive storage pile. The sources of emissions associated with the inactive coal pile include: 1) the transfer from inactive chain reclaimer to conveyor 4B (TP3), 2) the dozer and loader vehicle emissions from traveling on/around the pile (PIL1), 3) the pile maintenance activities which represent the loaders moving/transferring material around the pile (PIL1), and 4) the wind erosion emissions (PIL1). The emissions from dozers/loaders moving coal from the pile to the reclaim conveyor are quantified in the vehicle emissions from traveling on and around the pile (PIL1) and in the drop point emissions from transferring coal onto the pile (TP3).

34. I recalculated the unpaved storage yard emissions changing the silt content from 4.9% to 29% and control efficiency from 90% to 50%. My calculations increase emissions of PM10 and PM2.5 by factors of 25 and 2.5, respectively.

As discussed in response to specific comments, this comment has not identified flaws in the emission data provided by CCG for the subject emission units. As such, the revised emission data for these units prepared by this commenter is neither reasonable nor credible.

EQUIPMENT LEAK EMISSIONS

35. Equipment leaks are emissions from piping components and associated equipment components, including valves, pumps, compressors, process drain, and other components. When these components leak, they release small amounts of the material that is being handled resulting in emissions of those materials. These emissions are commonly called fugitive leaks. At the TEC, depending on the particular components, these emissions will include compounds found in the streams that pass through the components, VOM, CO, CO_2, H_2S, total reduced sulfur, and various HAPs, such as methanol and carbonyl sulfide.

[96] AP., v. l, p. 2-4.
[97] AP-42, Chapter 11.9, Table 11.9-1.

The aggregate emissions from leaks from these components can add up to a substantial amount because of the number of such components.[98]

The application claims only tiny emissions from leaks from these components, consistent with what one would expect from a facility using state-of-the art leakless and low-leak technology, which is not required for the TEC.[99] The projected emissions are inconsistent with the number of uncontrolled components, compared to actual measurements made at any other similar operating facility in allied industries such as refineries and chemical plants, ambient monitoring studies, and emission inventories from a number of other plants. This is an important issue, as the application eliminates all technically feasible options to control these emissions, arguing that none is cost-effective.

My revised emission projections, discussed in my comments, indicate that the TEC could emit three to six times more than indicated in the application.[100] The increases are sufficient to classify the TEC as a major source for HAPs, contribute significantly to ozone impacts, and render leakless components and a facility-wide LDAR program cost-effective and thus BACT for equipment leaks. In addition, the cost per ton[101] to control equipment leak emissions was significantly overestimated by underestimating uncontrolled emission and hence emission reductions. These comments explain why the application underestimates emissions from equipment leaks and corrects these estimates. My revised emission estimates then are used in later comments to correct the cost-effectiveness analysis in the BACT analysis.

The application estimated equipment leak emissions using three factors: (1) an emission factor for "total emissions", including all compounds in the mixture; (2) a control efficiency for the "MACT-like" leak detection and repair ("LDAR") program proposed for a subset of the components; and (3) the weighted average fraction of each pollutant in the total emissions or "speciation" factors. The emission factors, in pounds per hour per component ("lb/hr/component") for each type of component (valve, pump, compressor, etc.), were multiplied by the number of components of each type in various areas of the plant. Controlled emissions were then calculated for the high-leak components in two areas of the plant by multiplying total emissions by a control efficiency. The total emissions obtained in this fashion were then multiplied by "speciation factors" to estimate the emissions of each PSD and HAP pollutant.

In my later comments, I will discuss the emission factors, control efficiencies, and speciation factors used in these calculations. CCG underestimated emissions using this approach because it picked the lowest emission factors ever published for equipment leaks

---

[98] As described in the application (Application, v. 1, Appx. C and v. 3, Appx. D), the TEC is projected to have almost 25,000 of these components, including 18,798 connectors, 5,869 valves, 92 pumps, 61sample connectors, 20 compressors, 13 open ended lines, 115 pressure relief values vented to a vapor collection system and the flare, and 11 pressure relief valves not vented to a flare.

[99] The potential emissions indicated in the application are: CO - 30.5l ton/yr, VOM - 2.44 ton/yr, H_2S - 1.42 ton/yr, methanol - 1.0 ton/yr, COS - 1.05 ton/yr, CO_2 - 177.4 ton/yr, and CH_4 - 51.3 ton/yr.

[100] My estimates of these emissions are: CO - 118.2 ton/yr, VOM - 11.8 ton/yr, H_2S - 6.53 ton/yr, methanol - 5.30 ton/yr, COS - 6.68 ton/yr, CO_2 - 714.7 ton/yr, and CH_4 - 155.1.

[101] Cost-effectiveness or "cost per ton" is the annual cost of control per ton of pollutant removed. It is calculated by dividing the total annual cost of a control method in dollars by the amount of emissions removed by the control in tons per year. The uncontrolled emissions and the emission reductions achieved by the control are key factors in this calculation. If the uncontrolled emissions are underestimated, the cost per ton is overestimated, *i.e.*, dividing a given annual cost by a smaller number yields a higher dollars-per-ton value.

from an undocumented source for a non-representative industry, used excessively high control efficiencies, and failed to supported its speciation factors.

The comment's characterization of the fugitive equipment leak component (ELC) emission estimates for the TEC is not credible in light of the potential emissions estimates for other recently permitted gasification facilities.[102] Potential CO and VOC emissions from ELC at several recently permitted gasification facilities that share similar design features to the TEC compare reasonably well to the limits in the permit

[102] **As shown below, the annual potential CO and VOC emissions from ELC at several recently permitted gasification facilities that share similar design features to the TEC compare well to the annual limits in the permit [Condition 4.9.2(d)]. The variations in permitted emissions between these facilities is a function of several independent variables including: 1) The number of ELC included in the application; 2) the emission factors used to estimate emissions; 3) the stream compositions of CO and VOC in the process areas considered in the emission calculations, and 4) the control credit offered by the LDAR program implemented.**

Comparison of Emissions from Equipment Leaks for Similar Gasification Projects

Facility	Facility Location	Permit Issuance Date	Ref.	Annual Potential CO Emissions from Equipment Leaks (tpy)	Annual Potential VOC Emissions from Equipment Leaks (tpy)
Christian County Generation, LLC	Taylorville, IL	10/17/2011	--	30.51	2.44
Indiana Gasification	Rockport, IN	12/12/2011	1	9.45	3.21
Summit Texas Clean Energy, LLC	Ector County, Texas	12/28/2010	2	7.46	6.59
Kentucky Syngas, LLC	Central City, KY	9/24/2010	3	10.12	--
Cash Creek Generating, LLC	Henderson County, KY	5/5/2010	4	1.39	--
Power Holdings	Blissville Township, IL	10/26/2009	5	--	2.50
Hunton Energy Freeport Holdings, LLC	Freeport, TX	1/16/2009	6	7.66	0.11

[1] Indiana Gasification, *Indiana Gasification, LLC PSD Air Permit Application Indiana SNG Project* , April 20, 2011.

[2] TCEQ, *Emissions Source - Maximum Allowable Emission Rates for Permit Numbers 92350 and PSDTX1218* , December 28, 2010, available at https://webmail.tceq.state.tx.us/gw/webpub

[3] Kentucky Division for Air Quality, *Final Air Quality Permit Issued Under 401 KAR 52:020 for Kentucky Syngas, LLC* , September 24, 2010, available at http://dep.gateway.ky.gov/eSearch/. Project did not trigger PSD review for VOC, so no VOC potential emissions are included in the final permit or statement of basis report.

[4] Kentucky Division for Air Quality, *Final Air Quality Permit Issued Under 401 KAR 52:020 for Cash Creek Generating, LLC* , May 5, 2010, available at http://dep.gateway.ky.gov/eSearch/. Project did not trigger PSD review for VOC, so no VOC potential emissions are included in the final permit or statement of basis report.

[5] IEPA, *Construction Permit - PSD Approval NSPS Emission Units for Power Holdings of Illinois, LLC* , October 26, 2009. No CO emissions from fugitive equipment leaks are provided in the permit.

[6] TCEQ, *Emissions Source - Maximum Allowable Emission Rates for Permit Number 85209* , January 16, 2009, available at https://webmail.tceq.state.tx.us/gw/webpub.

Facility	Facility Location	Permit Issuance Date	Ref.	Annual Potential CO Emissions from Equipment Leaks (tpy)	Annual Potential VOC Emissions from Equipment Leaks (tpy)
Christian County Generation, LLC	Taylorville, IL	10/17/2011	--	30.51	2.44
Indiana Gasification	Rockport, IN	12/12/2011	1	9.45	3.21
Summit Texas Clean Energy, LLC	Ector County, Texas	12/28/2010	2	7.46	6.59
Kentucky Syngas, LLC	Central City, KY	9/24/2010	3	10.12	--
Cash Creek Generating, LLC	Henderson County, KY	5/5/2010	4	1.39	--
Power Holdings	Blissville Township, IL	10/26/2009	5	--	2.50
Hunton Energy Freeport Holdings, LLC	Freeport, TX	1/16/2009	6	7.66	0.11

[1] Indiana Gasification, *Indiana Gasification, LLC PSD Air Permit Application Indiana SNG Project* , April 20, 2011.

[2] TCEQ, *Emissions Source - Maximum Allowable Emission Rates for Permit Numbers 92350 and PSDTX1218* , December 28, 2010, available at https://webmail.tceq.state.tx.us/gw/webpub

[3] Kentucky Division for Air Quality, *Final Air Quality Permit Issued Under 401 KAR 52:020 for Kentucky Syngas, LLC* , September 24, 2010, available at http://dep.gateway.ky.gov/eSearch/. Project did not trigger PSD review for VOC, so no VOC potential emissions are included in the final permit or statement of basis report.

[4] Kentucky Division for Air Quality, *Final Air Quality Permit Issued Under 401 KAR 52:020 for Cash Creek Generating, LLC* , May 5, 2010, available at http://dep.gateway.ky.gov/eSearch/. Project did not trigger PSD review for VOC, so no VOC potential emissions are included in the final permit or statement of basis report.

[5] IEPA, *Construction Permit - PSD Approval NSPS Emission Units for Power Holdings of Illinois, LLC* , October 26, 2009. No CO emissions from fugitive equipment leaks are provided in the permit.

[6] TCEQ, *Emissions Source - Maximum Allowable Emission Rates for Permit Number 85209* , January 16, 2009, available at https://webmail.tceq.state.tx.us/gw/webpub.

[Condition 4.9.2(d)]. This generally shows that the ELC emissions estimates and associated BACT limits for the TEC are reasonable and appropriate.

As discussed later in the responses to this comment's individual arguments regarding ELC emissions, the ELC emissions estimates and control cost analyses provided in the Application are reasonable and appropriately justified based on the information in the permit record. Developing revised emissions estimates that grossly over-estimate CO, VOC, and GHG emissions from ELC at the TEC[103] and subsequently using these flawed and inappropriate emissions estimates in an updated control cost analysis does not indicate that CCG's analysis is incorrect. (It simply shows the direct linear relationship between emissions reductions and cost effectiveness for a given annualized control cost.) Thus, the costs of control for an LDAR program or leakless components have not been over-predicted due to under-estimates of ELC emissions.

36. CCG chose an undocumented adaptation of the emission factors for total organic compounds ("TOC") known as SOCMI (Synthetic Organic Chemical Manufacturing Industry) emission factors.[104] These were then used with undocumented chemical speciation data to estimate emissions of individual compounds or groups of compounds. These comment discuss the emission factors themselves. Subsequent comments discuss converting these into individual pollutant emissions.

SOCMI factors are not applicable to gasification plants. The unmodified version of these emission factors was developed by the USEPA based on measurements at 24 chemical plants, producing a range of synthetic organic chemicals.[105] The adaptation of the USEPA SOCMI emission factors used in the Application are the lowest possible emissions factors published anywhere that I am aware of for chemical processing plants and do not fairly represent emissions from the proposed facility. When estimating any emissions for purposes of PSD, USEPA emphasizes in the NSR Manual that "[f]or each emissions unit, the estimate should be based on the most representative data available." NSR Manual, Appendix C, p. 2.

The draft TCEQ guidance that the application relies on indicates that the SOCMI factors are generally appropriate for chemical plants.[106] This draft was never finalized. The USEPA document that these factors were based on identifies polymer and resin manufacturers as the source of the SOCMI factors.[107] The polymer and resin manufacturing industry, which manufactures plastics, glues, fiberglass backing material, fiber optics components, and other physical materials, is not similar to coal gasification in terms of types of equipment or feedstocks used. Coal gasification plants are more similar to oil refineries.

---

[103] Incidentally, as compared to the preliminary component counts included in Section C-24 to C-27 of Appendix C to Volume 1 of the Application and Section A-19 of Appendix A to Volume 3 of the Application, the facility-wide number of valves and pumps was miscounted in this comment. The correct number of valves is 5,864 and the correct number of pumps is 97. The comment also misstated the annual potential H_2S emissions from equipment leak components. The correct value cited in Table 3-2 of Volume 1 of the Application is 1.41 tpy.

[104] Ap., v. 1, Sec. 3.9, p. 3-17.

[105] USEPA, Protocol for Equipment Leak Emission Estimates, EPA-453/R- 95-017, November 1995, Sec. 2.3.1 and Table 2-1 (hereafter "USEPA 11/95"), *available at* USEPA, Protocol for Equipment Leak Emission Estimates, Report EPA-453/R-95-017, November 1995, Sec. 2.3.1 and Table 2-1 (hereafter Commenter's Exhibit 21 or "USEPA 11/95"), *available at* www.epa.gov/ttnchie1/efdocs/equiplks.pdf; USEPA, *Fugitive Emission Sources of Organic Compounds – Additional Information on Emissions, Emission Reduction, and Costs*, EPA-450/3-82-010, April 1982, http://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=91009YVL.txt; (hereafter Commenter's Exhibit 21 or "USEPA 4/82"), Sec. 2.1.6 and Table 2-12.

[106] Texas Commission on Environmental Quality (TCEQ), Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000, Draft. (Commenter's Exhibit 23)

[107] Commenter's Exhibit 21 (USEPA 11/95) and Commenter's Exhibit 22 (USEPA 4/82).

Further, SOCMI emission factors were developed for processes used to generate synthetic organic chemicals such as acetaldehyde, acetone, and phenol,[108] not for processes used to generate syngas and its byproducts, *e.g.*, air separation, raw syngas production, syngas conditioning, acid gas removal, sulfur recovery, methanation, and dehydration. The amount of TOC emissions from fugitive components depends on the chemicals being processed for many reasons.

Process streams with different chemical (*e.g.*, polarity) and physical properties (*e.g.*, temperature, pressure) will produce different TOC emission factors, *i.e.*, the escaping tendency of chemical inside processing units depends upon the composition of the contained material. The application and supporting file contain no evidence that the physical and chemical composition of IGCC process streams is similar to that of process streams in the synthetic organic chemical industry. The TOC emission factors developed for synthetic organic chemicals are not relevant to the production of syngas and SNG from coal. The Draft Permit itself makes this clear.

Condition 4.9.4(a) would exclude components at the TEC from 40 CFR 60 Subpart VVa "because the SNG and recovered sulfur produced at this plant are not products covered by the SOCMI NSPS." Condition 4.9.4.b excludes the Taylorville components from 35 IAC Part 215, Subpart Q "because none of the chemicals produced at the plant are synthetic organic chemicals or polymers listed in 35 IAC Part 215, Appendix D."

Thus, there is no basis at all for applying emission factors developed for these industries, specifically exempted from the Draft Permit, to the TEC. The stream composition data in the application for TEC, Appendix C, pp. C- 104 to C-111 indicate that the composition of IGCC process streams is more similar to those found in refineries than in chemical plants.

Coal gasification facilities are not chemical plants, which have had to keep tighter leak standards far longer than other industries as a practical matter due to the extremely hazardous nature and high value of the chemicals they handle. First, SOCMI facilities handle materials of greater value than those at an IGCC facility, providing an incentive to minimize equipment leaks. Second, a SOCMI facility typically handles highly toxic and hazardous substances, which must be minimized to prevent worker exposure. These conditions dictate design and operating practices at these facilities to minimize releases. The Application contains no evidence of similar concerns at the TEC. In fact, it irresponsibly rejects the use of leakless and low-leak technology on the basis of a flawed cost analysis. These components would routinely by used in the synthetic organic chemical industry to preserve feedstock and protect workers. This would result in lower emissions at a SOCMI facility than at a gasification facility such as the TEC without similar concerns.

Further, the synthetic chemical industry is largely characterized by smaller equipment and more batch processes that lend themselves more readily to improved control than the processes that would be used at the TEC. An IGCC plant uses larger equipment operating continuously at higher temperatures. These differences would result in higher emissions

[108] *See* Commenter's Exhibit 22 (USEPA 4/82), Table 2-12.

from an IGCC facility than from the process units in the synthetic organic chemicals industry that USEPA used to estimate the SOCMI factors.

In sum, the use of SOCMI average emission factors as developed by USEPA underestimates TOC and other emissions from the TEC. However, rather than use even these underestimates, CCG selects an unsupported adaptation of these USEPA factors which is lower still than the USEPA SOCMI factors.

The comment asserts that the "SOCMI Average without Ethylene" emission factors from the TCEQ equipment leak guidance document used in the application have no basis, and are not applicable to the TEC. Since coal gasification facilities are chemical plants and not petroleum refineries, marketing terminals, or oil and gas production operations, it was reasonable and appropriate to base the TEC emissions factors on SOCMI data. The comment is incorrect in the claim that the SOCMI factors somehow apply only to the polymer and resin manufacturing industries. SOCMI factors are based on a cross section of chemical manufacturing sources.[109] In the *Protocol for Fugitive Equipment Leak Emissions*, the USEPA states that polymer and resin manufacturers are only one example of where SOCMI factors are applicable.[110]

USEPA states "for process units in source categories for which emission factors and/or correlations have not been developed, the factors and/or correlations already developed can be utilized."[111] Since there are no equipment leak component factors specific to coal gasification plants, the TEC followed the criteria delineated in USEPA's *Leak Protocol* by considering (1) process design; (2) process operation parameters (i.e., pressure and temperature); (3) types of equipment used; and (4) types of material handled.[112] Applying these four factors, SOCMI emission factors were selected because the TEC has similar process design, operation parameters, types of equipment used, and process stream compositions to SOCMI facilities. The process streams at the TEC are primarily gaseous streams with light hydrocarbons (primarily CH_4), hydrogen (H_2), CO, and trace levels of H_2S, and VOM (raw syngas). In the acid gas removal process area, the process streams are aligned with chemical facilities classified as SOCMI, as methanol is common at SOCMI facilities. The basis for the selection of the emissions factors was laid out clearly in the Application and supported by many sources.

Rather than relying on the USEPA SOCMI average emission factors directly, CCG chose to rely on a more accurate adaptation of the SOCMI average factors developed by TCEQ using USEPA's raw equipment leak data broken out by industry-type. The adjustment to the USEPA SOCMI average emission factors was made to account for the higher leak rates at ethylene manufacturing facilities versus the other types of SOCMI sources evaluated in USEPA studies that did not have process streams with a high percentage of ethylene. These factors come from guidance published by the

[109] **Commenter's Exhibit 21, See page 2-8.**
[110] **Commenter's Exhibit 21, See page 2-6.**
[111] **USEPA, Protocol for Equipment Leak Emission Estimates. EPA-453/R-95-017, November 1995. See page 2-5.**
[112] **Commenter's Exhibit 21. See page 2-6.**

TCEQ and referenced as a basis in permits both in Texas and in other states.[113] The TCEQ guidance is based on voluminous data collected for USEPA's *Protocol for Equipment Leak Emissions Estimates*.[114] The more specific "SOCMI without ethylene" factors are specifically for process lines that contain less than 11% ethylene.

A simple comparison of the SOCMI average with ethylene, SOCMI average, and SOCMI average without ethylene emission factors presented on page 49 of the TCEQ equipment leak guidance document reveals that ethylene facilities skewed the SOCMI average factors to the high end due to the higher leak rates observed at these sources. If the SOCMI dataset of leak rates was normally distributed and all industry types exhibited the same types of leak rates, then the leak rates for one source type would not be expected to exceed the average by between factors of 1.4 to more than 10.4 depending on the component type (with an average factor of 3.5 across all component types considered).

This same evidence regarding elevated leak rates from ethylene facilities is provided in Tables 2-19 and 2-20 in *Fugitive Sources of Organic Compounds – Additional Information on Emissions, Emission Reductions, and Costs* (Commenter's Exhibit 22). Table 2-19 shows ethylene facilities have much higher percent leaking gas valves, light liquid valves, and light liquid pumps than any of the other 14 industry types evaluated. For example, the percentage of leaking light liquid valves at ethylene plants was 23.2% while the next highest leak rate was only 10.5% for cumene manufacturing facilities, and many other facilities had leak rates less than 1%. Table 2-20 shows emission factors for ethylene, vinyl acetate, and cumene process units and demonstrates ethylene units have much higher emission factors. This table also demonstrates that certain SOCMI process units such vinyl acetate units have very low leak rates in comparison to the USEPA SOCMI average factors and even TCEQ's SOCMI average without ethylene factors. For example, the light liquid valve factor observed at vinyl acetate process units is 0.00022 lb/hr/component while the SOCMI without ethylene factor is 0.0035 lb/hr/component or more than a factor of 15 higher than the factor referenced by USEPA. The SOCMI average without ethylene factors are clearly not the "lowest possible emissions factor published anywhere" when The comment provides a USEPA reference document in their own exhibits with emission factors for certain SOCMI categories that are far lower than the SOCMI average without ethylene factors.

The clear indication of a high bias for ethylene facilities led TCEQ to develop a more accurate set of emission factors that could be applied across the state for SOCMI facilities that did not contain process streams with high fractions of ethylene. The SOCMI without ethylene factors are still in use today, and in fact, TCEQ requires that SOCMI facilities with less than 11% percent ethylene use these factors to quantify potential emissions from ELC in all construction permit applications submitted in the state. The recently permitted Summit Texas Clean Energy gasification facility used the SOCMI average without ethylene factors with TCEQ LDAR program control credits

---

[113] **Texas Commission on Environmental Quality, "Emissions Factors for Equipment Leak Fugitive Components," January 2008. (Commenter's Exhibit 24).**
[114] **Commenter's Exhibit 21.**

applied in certain process areas to quantify the CO and VOC annual emission rates presented in the emission comparison above.

Use of the SOCMI factors is consistent with what other applicants and agencies have used for coal gasification facilities. While the TEC is exempt from the SOCMI NSPS, this does not influence the decisions about the selection of representative emission factors. The comment's assertion that emissions factors and NSPS applicability are synonymous is incorrect. USEPA itself has stated that equipment leak GHG emissions from coal gasification can be calculated according to the same methodologies used for petrochemical plants which include certain types of SOCMI facilities.[115] In this statement, USEPA expressly identifies two coal gasification facilities, the Dakota Gasification Company in North Dakota and Eastman Chemical in Tennessee. A review of data collected by Eastman Chemical for its coal gasification facility's Title V emissions report indicates the opposite of the comment's unsubstantiated claims – that the use of SOCMI without ethylene factors may not just be appropriate, but are also a conservative *overestimate* of equipment leak component fugitive emissions.[116]

In this regard, the emission factors used by Eastman Chemical in the Title V permit renewal for the AGR, which are based on a 1994/1995 screening study conducted in accordance with the USEPA's Equipment Leak Protocol and used to support site-specific USEPA Correlation Approach emission calculations, are significantly lower than the SOCMI without ethylene emission factors for all component types.[117] Although the Eastman facility is subject to annual audible, visual, and olfactory (AVO) inspections for the gasification area and quarterly AVO inspections for the AGR process area, it is not clear from the permit application if these control measures were being implemented at the time the 1994/1995 screening study was collected. Regardless, AVO inspections on an annual or quarterly basis are expected to only provide a small reduction in emissions as compared to the uncontrolled base case, so the Eastman emission factors should be viewed as essentially uncontrolled even if the AVO program was being implemented at the time the screening study was conducted. To illustrate the relatively low control credits offered by AVO inspections, the TCEQ equipment leak guidance document only allows for a 30% control credit for weekly AVO inspections of connectors. The reduction of equipment leak emissions achieved at Eastman using quarterly/annual AVO inspections is expected to be much less than 30% given the infrequent nature of the inspections in comparison to the weekly interval envisioned by TCEQ. This information for the Eastman facility shows that the SOCMI without ethylene emission factors may overestimate fugitive emissions from

---

[115] **USEPA, Technical Support Document for Petrochemical Production Sector: Proposed Rule for Mandatory Reporting of Greenhouse Gases. September 9, 2008.**

[116] **"Major Source Operating Permit Application, PES B-334-1," for Tennessee Operations, Eastman Chemical Company's Acid Gas Removal and Sulfur Recovery Plants, April 18, 2005, pages C-5 through C-17.**

[117] ***Eastman Title V Renewal Application for AGR and SRU***

gasification facilities by almost a factor of 10 for gas/vapor valves.[118] Based on these data, one can conclude that TCEQ's SOCMI without ethylene factors will provide a conservative estimate of emissions from ELC that are part of a gasification process.

The comment's main assertion regarding the use of SOCMI emission factors is that there is no basis for using these factors in the coal gasification industry, yet they offer their own claim that refinery factors are more similar to coal gasification facilities without supporting justification. The only apparent reason that the comment would claim refinery factors should be used at coal gasification facilities rather than SOCMI factors is that refinery average emission factors are substantially higher than SOCMI average factors.

A general understanding of the process materials present at a coal gasification facility and a refinery clearly differentiate the two as independent and separate processes. The syngas and SNG to be processed at the TEC are mixtures of light gases including primarily CO, H_2, CO_2, CH_4, and water vapor. Refineries process crude oil, a heavy liquid mixture of various hydrocarbons, which is not physically or chemically similar to the syngas and SNG processed at TEC. The light gases at a coal gasification facility are primarily comprised of low molecular weight constituents. Following the gasifiers, there are only trace levels of carbon-based compounds in the process streams at the TEC with more than one carbon atom. In contrast, refinery products include higher

[118] **Comparison of SOCMI Average and Eastman ELC Emission Factor**

Component Type-Service	TCEQ's SOCMI Average w/o Ethylene Emission Factors (lb/hr/comp.)	TCEQ's SOCMI Average w/o Ethylene Emission Factors (ton/yr/comp.)	Eastman Emission Factors (ton/yr/comp.)	Ratio of Eastman to SOCMI Emission Factors (%)
Pump-Light Liquid	0.0386	0.1691	0.1500	88.7%
Pump-Heavy Liquid	0.0161	0.0705	0.0023	3.3%
Valves-Gas	0.0089	0.0390	0.0041	10.5%
Valve-Light Liquid	0.0035	0.0153	0.0016	10.4%
Valve-Heavy Liquid	0.0007	0.0031	0.0005	16.6%
Connectors-Gas	0.0029	0.0127	0.0014	11.0%
Connectors-Light Liquid	0.0005	0.0022	0.0014	63.9%
Connectors-Heavy Liquid	0.0001	0.0003	0.0002	68.5%
PRVs-All	0.2293	1.0043	0.1200	11.9%
Sampling Connections-All	0.0330	0.1445	0.0110	7.6%

Component Type-Service	TCEQ's SOCMI Average w/o Ethylene Emission Factors (lb/hr/comp.)	TCEQ's SOCMI Average w/o Ethylene Emission Factors (ton/yr/comp.)	Eastman Emission Factors (ton/yr/comp.)	Ratio of Eastman to SOCMI Emission Factors (%)
Pump-Light Liquid	0.0386	0.1691	0.1500	88.7%
Pump-Heavy Liquid	0.0161	0.0705	0.0023	3.3%
Valves-Gas	0.0089	0.0390	0.0041	10.5%
Valve-Light Liquid	0.0035	0.0153	0.0016	10.4%
Valve-Heavy Liquid	0.0007	0.0031	0.0005	16.6%
Connectors-Gas	0.0029	0.0127	0.0014	11.0%
Connectors-Light Liquid	0.0005	0.0022	0.0014	63.9%
Connectors-Heavy Liquid	0.0001	0.0003	0.0002	68.5%
PRVs-All	0.2293	1.0043	0.1200	11.9%
Sampling Connections-All	0.0330	0.1445	0.0110	7.6%

From Eastman Title V Renewal application for AGR and SRU

molecular weight, long chain hydrocarbons throughout the entire process including the crude distillation units, fluidized catalytic cracking units, continuous catalytic reforming units, and gasoline, diesel, and kerosene storage and blending operations. The only location within a petroleum refinery that contains process gases which even remotely resemble syngas or SNG is the refinery fuel gas system which is used to collect methane and other light hydrocarbons from the overhead of equipment processing heavier liquid petroleum derivatives. The sulfur recovery unit at the TEC and a refinery would also process similar process gases, but this process area is not a significant source of VOC emissions from ELC. Furthermore, the TEC will contain components in methanol service. This is similar to process streams at SOCMI facilities (methanol is a commonly used solvent at chemical plants and is specifically delineated as a compound present at SOCMI facilities in the *Protocol for Fugitive Equipment Leak Emissions*), and it is dissimilar to refineries, which rarely use methanol, if any.

Refinery factors from USEPA's Equipment Leak Protocol are based on equipment in the Refinery Assessment Study that typically handled liquid process streams (not gaseous) containing 10 weight percent or less methane, with the balance primarily VOM.[119] These primarily-VOM streams are laden with long-chain and aromatic hydrocarbons. The phase (liquid versus. gas) and the defined constituent concentration of typical refinery process streams are not similar to the gaseous streams at the TEC. Unlike refineries, SOCMI facilities include process streams primarily comprised of low molecular weight constituents. In their original development, SOCMI factors were based on a range of 24 process units, representing a cross section of the population of SOCMI. The sources were selected in 1984 to help gain information of the SOCMI emissions.[120] In addition to acetaldehyde, acetone, and phenol – the few chemicals presented in the comment's narrow reference – the SOCMI factors were also developed with at least 21 other chemicals from chemical manufacturing processes, including methanol. The SOCMI average emission factors and the SOCMI average without ethylene factors derived by TCEQ from the same data should provide a conservatively high estimate for actual emissions from the TEC since they were developed based on leak rate data from existing chemical plants constructed many years ago.[121] In light of this information, it is clear that the comment has no basis for stating the stream composition presented in Appendix C of the permit application is more similar to a refinery than a chemical plant. For the reasons discussed above, equipment leak emissions from TEC will be more akin to SOCMI facilities than to refineries.

The comment's claim that SOCMI facilities handle material of a greater value than those at a coal gasification facility is offered with no support based on literature, studies, or even market values. The argument that material value somehow dictates environmental performance without the need for implementing BACT control measures mandated by the Clean Air Act is oddly inconsistent with subsequent comments that the ELC BACT requirements in the Draft Permit are not adequate.

---

[119] **Commenter's Exhibit 21. See page 2-16.**

[120] **USEPA, Fugitive Emission Sources of Organic Compounds – Additional Information on Emissions, Emission Reduction, and Costs. EPA-450/3-82-010, April 1982 (Referred to as Commenter's Exhibit 22. See Section 2.1.6 (pg. 38 of 260).**

[121] **Commenter's Exhibit 22, Section 2.1.6 and Table 2-12 (pg.38-19 of 260).**

The comment is made to suggest that the coal gasification facility equipment leak components would not be designed to the same leak-prevention standards of the SOCMI facilities from which the uncontrolled emission factors were derived. Facilities are not designed to leak raw materials used to produce end products – whether SOCMI or other types.

Similarly, the suggestion that SOCMI facilities have smaller equipment and batch process lines is also unsubstantiated and not relevant. Equipment leak component emission factors are expressed on a per component basis not a size basis for any industry type. The same emission factor is used for a one inch diameter valve and a 6 inch diameter valve, and the size of the component is not a determining factor for the magnitude of emissions on a lb/hr/component basis. As such, the size of a component would not impact the calculations in the application and basis for the TEC permit.

For all of the above reasons, SOCMI without ethylene factors are appropriate, conservative estimates for the fugitive equipment leak emissions from the TEC.

37. Rather than using USEPA's average SOCMI or refinery emission factors, CCG selected an adaptation of the SOCMI factors, "SOCMI without ethylene" used by TCEQ in its draft *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives.*[122] This guidance was never finalized and the emission factors are undocumented. These are also the lowest emission factors ever proposed for SOCMI sources. The adaptation used in the Application is called the "SOCMI without ethylene" emission factors. These factors reportedly apply to process lines in SOCMI plants that contain less than 11% ethylene. However, the relevance of this categorization to leaks from fugitive components in a coal gasification plant is unclear and undocumented. The categorization based on the ethylene content of a process stream in a chemical plant is not relevant to the types of gases produced from the gasification of coal and, specifically, ethylene is not a byproduct.

The cited draft TCEQ document and subsequent TCEQ publications contain no support at all for the ethylene-adjusted SOCMI emission factors used by CCG. There is no explanation of how TCEQ developed these factors or any analysis of why they are representative of any gasification plant. The average SOCMI and refinery emission factors, on the other hand, are carefully documented in USEPA reports cited above. The average SOCMI and refinery emission factors developed by USEPA, on the other hand, are well documented.[123] Thus, there is no basis for the equipment leak emission factors used for the TEC.

TCEQ staff indicate the ethylene-adjusted factors were developed from the same data as USEPA used to determine average SOCMI emission factors, but adjusted to exclude ethylene facilities which had higher emissions than other types of chemical plants. TCEQ staff (but not USEPA) assumed this was due to the fact that ethylene is a smaller molecule than others present and therefore more likely to leak in larger amounts from a given size hole. Thus, TCEQ recalculated SOCMI emission factors for volatile organic compounds ("VOC") for two groups of data: (1) ethylene facilities (the "with ethylene" factors) and (2)

[122] Ap., v. 1, Sec. 3.9, p. 3-17, and Texas Commission on Environmental Quality, Emissions Factors for Equipment Leak Fugitive Components, January 2008, *available at* http://www.tceg.texas.gov/assets/public/implementation/air/ie/pseiforms/ef elfc.pdf (Commenter's Exhibit 24)
[123] USEPA, November 1995 as summarized in Tables 2-1 and 2-2.

all other chemical facilities (the "without ethylene" factors used for the TCE). TCEQ requires the use of "with ethylene" factors for streams containing greater than 80% ethylene and the lowest factors, "without ethylene," for streams containing less than 11% ethylene.[124]

The application assumes without any support that process streams at the plant will contain only the larger molecules assumed to leak at the smaller rate of the non-ethylene chemical plants.[125] This reasoning does not apply to process streams in gasification plants as they contain high concentrations of compounds smaller in size than ethylene, such as methane, hydrogen and carbon monoxide, which are not present in SOCMI plants in large amounts, if at all, and were not considered in the derivation of the TCEQ factors. Under this reasoning, the higher "with ethylene" emission factors would be more applicable due to the predominance of smaller molecules.

Regardless, it is known based on measurement studies that VOC emissions from equipment leaks are underestimated by factors of 3 to 20 even when estimated using the conventional USEPA emission factors.[126] The U.K.'s National Physical Laboratory (equivalent to the U.S. National Institute of Standards and Technology) has compared direct measurements of fugitive VOCs with those estimated by emission factors for over a decade and found the direct measurements were about three times higher than the emission factor estimates on a plant-wide basis.[127] USEPA auditors have also found far more leaks than reported by the facility's program, indicating higher routine emissions than belied by the data.[128]

Recent studies confirm the approach used here to estimate fugitive VOC emissions result in significant underestimates in VOC emissions. Monitoring and modeling studies in Texas, the source of guidance used to estimate emissions from several sources in this Application, have demonstrated "severe inconsistencies" between reported and measured emissions. One study concluded: "We believe that our results show that the inventory of industrial VOC emissions [prepared using TCEQ calculation methods] is inaccurate in its location, composition, and emission rates of major sources... Most of the emissions are so-called fugitive emissions from leaking valves, pipes, or connectors, of which there are tens of thousands in a large facility."[129]

---

[124] Email from Texas Commission on Environmental Quality to Phyllis Fox, December 9, 2011 (Commenter's Exhibit 25).
[125] Ap., v. 1, Sec. 3.9, p. 3-17 and Ap., v. 1, Appx. C, pp. C-105 to C-111.
[126] Allan K. Chambers, et al., Direct Measurement of Fugitive Hydrocarbons from a Refinery, *J. Air & Waste Mgmt. Ass'n*, 58:1047-1056 (2008), at 1054 and Table 7 (Commenter's Exhibit 26); Clearstone Engineering Ltd., September 6, 2006 (Commenter's Exhibit 27); M. Kihlman, et al., *Monitoring of VOC Emissions from Refineries in Sweden Using the SOF Method*, http://www.fluxsense.se/reports/paper%202%20final%20lic.pdf (Commenter's Exhibit 28); IMPEL, Diffuse VOC Emissions, December 2000, at p. 38 (Commenter's Exhibit 29); USEPA, Office of Inspector General, EPA Can Improve Emissions Factors Development and Management, Evaluation Report, Report No. 2006-P-00017 (March 22, 2006), pp. 11-12 (summarizing the Texas 2000 Air Quality Study… "This primarily involved under reporting of emissions from flares, process vents, and cooling towers, as well as from fugitive emissions (leaks). The under-reporting was caused largely due to the use of poor quality emissions factors.")(Commenter's Exhibit 30); USEPA, VOC Fugitive Losses: New Monitors, Emissions Losses, and Potential Policy Gaps, 2006 International Workshop (October 25-27, 2006), ("VOC Fugitive Losses") p. vii and p. 1 ("emissions from refinery and natural gas operations may be 10 to 20 times greater than the amount estimated using standard emission factors.") (Commenter's Exhibit 31); *Id*., p. 3 ("Typically, measurements did show some 10 to 20 times higher emissions than calculated at initial measurement activities…Today, after long term experience with the measurements and also after successful improvements of plant operations regarding emissions, emission levels of some 3 to 10 times higher than what is theoretically calculated are typically seen.")
[127] VOC Fugitive Losses, at.23. *See* also results of Swedish studies in this same report at p. 213.
[128] *See* USEPA's recent refinery settlements at http://www.epa.gov/compliance/resources/cases/civil/caa/oil/index.html.
[129] Ronald C. Henry and others, Reported Emissions of Organic Gases are not Consistent with Observation, Proc. Natl. Acad. Sci., v. 94, June 1997, pp. 6596-6599; available at: http://www.pnas.org/content/94/13/6596.full.pdf.

This conclusion has been confirmed in numerous studies in the past decade, *viz.*, "The analysis presented here for 2000, 2002, and 2006 measurements in the Houston-Galveston Brazoria area indicates that emission inventory inaccuracies persist."[130] "We conclude that consistently large discrepancies between measurement-derived and tabulated (alkene/NOx) ratios are due to consistently and substantially underestimated VOC emissions from the petrochemical facilities."[131] "The results... show that the emissions of ethene and propene, obtained by SOF [solar occultation flux], are on average an order of magnitude larger than what is reported in the 2006 daily EI [Emission Inventory]."[132]

A 2006 study reported: "... we do not find good agreement between the measured plume composition and the VOC speciation in the emissions inventory. These observations are not surprising, as previous research has shown that emission fluxes of individual VOCs may be underestimated by as much as 1-2 orders of magnitude in inventories for the Houston area... The frequent lack of correlation between large VOC enhancements and enhancements in SO_2, NOx and CO suggests large, non-combustion sources of VOCs"[133] [*e.g.*, fugitive sources]. One study, for example, reported that measurements of ethene from petrochemical facilities were one to two orders of magnitude higher than reported in the emission inventory.[134] Monitoring data collected during the 2006 Texas Air Quality Study demonstrated that "[i]ndustrial ethylene and propylene emissions in the NEI05-REF are greatly underestimated relative to the estimates using SOF measurements in the Houston Ship Channel during the study period."[135]

These and other studies have consistently shown based on actual monitoring that emissions estimated using TCEQ emission factors has underestimated VOC emissions by significant amounts. The connection between these long discredited emission factors and an IGCC facility is even more tenuous.

"SOCMI without ethylene" emission factors are appropriate for coal gasification facilities. As discussed in a previous response, the TEC will have gas streams similar to SOCMI plants. Furthermore, the widely applied SOCMI without ethylene factors are specific to process streams with less than 11% ethylene, and were derived by TCEQ by

---

[130] R.A. Washenfelder and others, Characterization of NOx, SO_2, Ethene, and Propene from Industrial Emission Sources in Houston, Texas, J. Geophys. Res., v. 115, D16311, 2010 (Commenter's Exhibit 33); J.A. de Gouw and others, Airborne Measurements of Ethene from Industrial Sources using Laser Photo-Acoustic Spectroscopy, Environ. Sci. Technol., v. 43, no. 7, 2009, pp. 2437-2442 (Commenter's Exhibit 34); B.T. Jobson and others, Hydrocarbon Source Signatures in Houston, Texas: Influence of the Petrochemical Industry, J. Geophys. Res., v. 109, 2004 (Commenter's Exhibit 35); T. Karl and others, Use of Proton-transfer-reaction Mass Spectrometry to Characterize Volatile Organic Compound Sources at the La Porte Super Site during the Texas Air Quality Study 2000, J. Geophys. Res., v. 108(D16), 2003 (Commenter's Exhibit 36); L.I. Kleinman and others, Ozone Production Rate and Hydrocarbon Reactivity in 5 Urban Areas: A Cause of High Ozone Concentration in Houston, Geophys. Res. Lett., v. 29, no. 10, 2002 (Commenter's Exhibit 37); J. Mellqvist and others, Measurements of Industrial Emissions of Alkenes in Texas using the Solar Occultation Flux Method, J. Geophys. Res., v. 115, 2010 (Commenter's Exhibit 38); T.B. Ryerson and others, Effect of Petrochemical Industrial Emissions of Reactive Alkenes and NOx on Tropospheric Ozone Formation in Houston, Texas, J. Geophys. Res., v. 108(D8), 2003 (Commenter's Exhibit 39); B.P. Wert, Signatures of Terminal Alkene Oxidation in Airborne Formaldehyde Measurements during TexAQS 2000, J. Geophys. Res., v. 108(D3), 2003.(Commenter's Exhibit 40)

[131] T.B. Ryerson and others.

[132] Mellqvist and others.

[133] Daniel Bon and others, Evaluation of the Industrial Point Source Emission Inventory for the Houston Ship Channel Area Using Ship-Based, High Time Resolution Measurements of Volatile Organic Compounds, CIRES; available at: http://cires.colorado.edu/events/rendezvous/posters/detail.php?id=3866.(Commenter's Exhibit 41)

[134] E.B. Cowling and others, A Report to the Texas Commission on Environmental Quality by the TexAQSII Rapid Science Synthesis Team, Prepared by the Southern oxidants Study Office of the Director at North Carolina State University, August 31, 2007, available at: http://aqrp.ceer.utexas.edu/docs/RSSTFinalReportAug31.pdf. (Commenter's Exhibit 42)

[135] S.-W. Kim and others, Evaluations of NOx and Highly Reactive VOC Emission Inventories in Texas and the Implications for Ozone Plume Simulations during the Texas Air Quality Study 2006, Atmos. Chem. Phys. Discuss, v. 11,2011, pp. 21,201 -21,265, available at: http://www.atmos-chem-phys-discuss.net/11/21201/2011/acpd-11- 21201-2011.pdf. (Commenter's Exhibit 43)

refining the categorization of the source sampling from the same data pool supporting USEPA's Equipment Leak Protocol. TEC's predominantly low-VOM streams will contain less than 11% ethylene, thus it is appropriate to use this refined data as the basis for emissions factors, as guided by TCEQ and similarly applied by agencies across the nation.

The SOCMI without ethylene factors also are not the lowest factors ever proposed for SOCMI sources. The stratified emission factors referenced in TCEQ's email exchange with Phyllis Fox and referenced in Table 7-4 of the USEPA guidance document entitled *Handbook of Control Techniques for Fugitive VOC Emissions from Chemical Process Facilities* are significantly lower than the SOCMI without ethylene factors.[136] The stratified factors are a function of screening value, and for components with screening values less than 1,000 ppm, the stratified emission factors can be more than an order of magnitude less than the SOCMI average without ethylene factors depending on component type. A screening value is just another term for the measured concentration at the leak interface of a ELC. This same relationship between screening value and emission factor can be observed by reviewing the SOCMI screening ranges emission factors provided in Table 2-5 of the USEPA Equipment Leak Protocol. This table shows that non-leaking components with screening values less than 10,000 ppm have significantly lower emission factors than the SOCMI average without ethylene factors. The predominant component types present at the TEC that produce the largest amount of fugitive emissions are gas/vapor valves, light liquid valves, light liquid pumps, gas/vapor connectors, light liquid connectors, and compressors. Based on USEPA's SOCMI screening average approach, the following percentages of components would all have to be leaking simultaneously at a pegged screening value of 10,000 ppmv for the SOCMI average without ethylene factors to underestimate actual emissions from the TEC: 5.0% of gas/vapor valves, 1.6% of light liquid valves, 6.5% of light liquid pumps, 1.1% of gas/vapor connectors, 0.3% of light liquid connectors, and 9.0% of compressors.

The SOCMI leak rate data broken out by process unit type in Table 2-19 of Commenter's Exhibit 22[137] can be compared against these calculated leak rates to determine whether or not they are likely to occur at the TEC. For gas/vapor valves, only four of the 14 process unit types showed leak percentages above 5.0%, and two of these four process unit types contain a significant amount of ethylene in their process streams. Similarly, for light liquid pumps, only two of the 14 process units showed leak percentages above 6.5% and one of them was an ethylene process unit. While the calculated light liquid valve and connector leak percentages may be more reasonable in comparison to data from Commenter's Exhibit 22, that data is only a way of evaluating the appropriateness of the SOCMI without ethylene factors, and in no way indicates that the TEC would exceed the BACT emissions limits in the permit if a higher percentage of leaking components than those calculated occurred in practice. Another reference point for the percentage of leaking components that may be considered

---

[136] **USEPA, Office of Research and Development, *Handbook of Control Techniques for Fugitive VOC Emissions from Chemical Process Facilities*, EPA/525/R-93/005, March 1994, available at http://nepis.epa.gov/Exe/ZyPURL.cgi?Dockey=30004M36.txt**

[137] **USEPA, Fugitive Emission Sources of Organic Compounds – Additional Information on Emissions, Emission Reduction, and Costs. EPA-450/3-82-010, April 1982 (Referred to as Commenter's Exhibit 22)**

"high" for chemical plants are the percentages referenced by USEPA for implementing more stringent quality improvement programs under 40 CFR 63 Subpart H. Pursuant to 40 CFR 63.175(b), facilities are required to implement quality improvement programs for valves until the percentage of leaking valves falls below 2 percent. Similarly for pumps, a quality improvement program is required if more than 10 percent of the monitored pumps are leaking in any 6-month rolling period [refer to 40 CFR 63.176(a)]. In relation to these percentages cited by USEPA, the leak percentages calculated above are not expected to occur because of: 1) the MACT-equivalent LDAR program that will be implemented on ELC in high-VOM concentration service, 2) the state-of-the-art design of the TEC, and 3) the good work practices for identifying leaking components included in the permit [Condition 4.9.2(b)].

The comment asserts that TCEQ's guidance and emission factors are not appropriate because: 1) They were not finalized; and 2) Categorization of SOCMI factors based on ethylene content is not relevant to gasification facilities, as the basis is undocumented and they are unsupported compared to USEPA's factors, the TEC's gas streams contain speciated compounds with lower molecular weight than ethylene, and a few citations from parts of independent studies on regional, macro-level emissions suggest that both USEPA's and TCEQ's emission factors are underestimates for actual emissions from existing refineries and SOCMI facilities.

None of these reasons are valid for the TEC. First, although the TCEQ guidance document was published as a "draft", it is widely applied in practice. In a similar fashion, the USEPA's NSR Manual is often cited and relied on as a reference in determining the sufficiency of permitting actions, although it too has not progressed beyond a "draft". As further corroborating evidence, use of these factors is consistent with numerous other permits and permit applications for coal gasification facilities that rely on either USEPA's Equipment Leak Protocol SOCMI average emission factors or TCEQ's SOCMI without ethylene factors.[138]

CCG specifically selected the SOCMI without ethylene factors as all streams at the TEC will have less than 11% ethylene – precisely what qualifies a facility to utilize these factors. It is not necessary for ethylene to be a byproduct of the facility in order to utilize "without ethylene" factors. TCEQ developed subsets of refined emission factors from USEPA's dataset of SOCMI facilities based on whether ethylene was or was not present in the streams in significant amounts, as the SOCMI data suggested that those facilities with high VOM streams including ethylene warranted a separate emissions factor. It should be noted that TCEQ did not utilize undocumented sampling, but instead derived their equipment leak emission factors based on the same source sampling results utilized as the basis for USEPA's *Protocol for Equipment Leak Emissions Estimates* – the same source data that the comment refers to as "well documented".[139] Suggesting that TCEQ's factors have no basis, but that USEPA's

[138] **These facilities and agencies include: TransGas Development Systems, LLC (West Virginia Department of Environmental Protection); Power Holdings of Illinois (Illinois EPA); Southeast Idaho Energy, LLC (Idaho Department of Environmental Quality); Medicine Bow Fuel and Power, LLC (Wyoming Department of Environmental Quality); Mesaba Energy Project (Minnesota Pollution Control Agency); Kentucky Syngas, LLC (Kentucky Department of Environmental Protection); Hunton Energy Freeport Holdings, LLC (TCEQ); and Summit Texas Clean Energy, LLC (TCEQ).**

[139] **Sierra Club/Natural Resources Defense Council, Comments, January 3, 2012, p. 30.**

factors "are carefully documented" is contradictory. TCEQ's emission factors are simply a refinement of USEPA's larger categorization. Given that the streams at the TEC contain no ethylene, using refined SOCMI without ethylene emission factors is appropriate to determine the potential emissions from the equipment leak components.

The comment concludes, based on an incorrect interpretation of TCEQ's statements in Commenter's Exhibit 25,[140] that TCEQ decided to differentiate the SOCMI average emission factors based on the presence of ethylene in the process stream simply based on the assertion that ethylene is a small molecule and would leak at a higher lb/hr/component rate than other SOCMI chemicals. As clearly explained by Dana Poppa-Vermillion in her 12/9/11 3:29 PM email, the real reason that TCEQ created the SOCMI without ethylene factors was that "the Texas Air Control Board staff felt the inclusion of the ethylene facilities skewed the emission factors high since the ethylene facilities had higher emissions than the chemical facilities which did not handle ethylene."[141] The theoretical principle that may have caused this to be the case is irrelevant and can hardly be isolated to molecular size given the myriad of variables that affect the leak rate from a particular component including, process stream temperature, pressure, and composition, design and age of the component, and corrosivity of the process stream contacting the component, just to name a few. Thus, using molecule size to determine the applicability of the SOCMI without ethylene emission factors would be inconsistent with the fundamental basis of the factors and unsupported based on TCEQ guidance on the topic of quantifying equipment leak emissions. The only relevant criteria for whether SOCMI without ethylene factors are applied to a particular chemical facility type is the concentration of ethylene in the process streams and not the similarity of the chemical compounds present to ethylene.

On a technical basis, the argument that the emissions factors are inappropriate because TEC's process streams will contain "high concentrations of compounds smaller in size than ethylene" using methane, hydrogen, and carbon monoxide as examples is flawed. It confuses molecule size with molecular weight, which are not the same. Unlike the specific examples listed as having a smaller molecular weight, the ethylene molecule has a carbon-carbon double bond, represented by $H_2C=CH_2$, which tends to decrease the overall size of a molecule in comparison to hydrocarbons with only single bonds like methane. The Eastman emission factors referenced previously based on actual sampling data collected at an operating gasification facility with syngas process streams containing CO, H_2, and CH_4 indicate leak rates that are much lower than those at ethylene facilities, which disproves the notion that leak rates are somehow directly linked with molecular size.

The comment's final argument that the SOCMI without ethylene emission factors are not appropriate is based on narrow citations from several unrelated reports, many based on the results of single, macro-level studies of optical sensing technology on refineries, not on coal gasification facilities. The comment cites studies such as *Direct Measurement of Fugitive Emissions of Hydrocarbons From a Refinery* (Commenter's

[140] Email from Texas Commission on Environmental Quality to Phyllis Fox, December 9, 2011 (Referred to as Commenter's Exhibit 25)
[141] Commenter's Exhibit 25, p. 1.

Exhibit 26)[142] to note that VOC emissions from refineries as a whole may be 3 to 20 times higher than USEPA's emission factors from the *Protocol for Equipment Leak Emissions Estimates.* This study is not robust, but was based on a short-term 10 day analysis of a single, foreign refinery. The data was collected using optical sensing technology tuned to methane (not a VOC), C2+ hydrocarbons (not present in significant quantities at the TEC), and benzene (present only as a trace level contaminant if at all) to offer a broad assessment of emissions from tank storage, delayed coker, coker black water pond, cooling towers, and processing areas for fractionation and upgrading. These process areas within a refinery would not only have fugitive VOC emissions from equipment leaks but also VOC emissions from breathing and working losses at storage tanks, VOC emissions from cooling towers, and VOC emissions from refinery process vents. A distant optical scan would not be able to differentiate the portion of the VOC emissions that is attributable to equipment leaks and the portion attributable to the other refinery sources. More importantly, none of the refinery equipment that could have contributed to the measured VOC emissions offsite is comparable to or will be present at the TEC besides storage tanks and cooling towers. Including each of these refinery process areas in a distant optical scan is far too broad to provide a direct comparison of equipment leak component-only emissions determined using Method 21 in USEPA's *Protocol for Equipment Leak Emissions Estimates* even assuming the scanning process could somehow determine the portion of VOC emissions emitted by ELC. The other studies referenced by The comment has similar issues in terms of the ability to quantify emissions from specific equipment leak components within an industrial facility. USEPA in the *Emission Estimation Protocol for Petroleum Refineries* states that optical leak imaging techniques using passive infrared spectral imaging have not yet been developed to the point of being able to quantify emissions, and remote sensing techniques including Differential Absorption Light Detection and Ranging (LIDAR) and Solar Occultation Flux are not yet approved by USEPA as a method of quantifying emissions from equipment leaks or any other sources.[143]

In summarizing the findings of the various optical sensing studies, the comment argues that commonly used ELC emission factors significantly under estimate VOC emissions, but in the very same comment, they state that USEPA's factors are "well documented" and should be used in place of the TCEQ SOCMI without ethylene factors. Furthermore, the citation from the Commenter's Exhibit 26 is specific to the underestimates caused by refinery emission factors, which are the very same factors the comment suggests are more appropriate and should have been used by the TEC. The comment even uses these factors to "re-calculate" potential emissions (addressed below), and to revise the control cost analysis for LDAR and leakless components prepared by the TEC. Through the comment's own argument, they have identified why their suggestions are not appropriate.

38. I recalculated uncontrolled total emissions from equipment leaks using other, more representative emission factors, including EPA's average SOCMI factor, TCEQ's "with

[142] **Allan K. Chambers, et al., Direct Measurement of Fugitive Hydrocarbons from a Refinery, *J. Air & Waste Mgmt. Ass'n*, 58:1047-1056 (2008), at 1054 and Table 7; Clearstone Engineering Ltd., September 6, 2006 (Commenter's Exhibit 26)**

[143] **RTI International submitted to USEPA OAQPS, Emission Estimation Protocol for Petroleum Refineries, September 2010, pg. 2-1.**

ethylene" factor, and EPA's average refinery factor. I followed the Application's procedure in every respect except for the underlying emission factors themselves. My detailed calculations are provided in Commenter's Exhibit 19**.**

First, this table shows that the Application significantly underestimated total emissions from equipment leaks due to the use of an erroneous emission factor. The underestimate is even greater when the other errors, discussed elsewhere in these comments, are factored in, *e.g.*, high control efficiencies inconsistent with the permit conditions, errors in applying control efficiencies, failure to sum emissions for all controlled pollutants, failure to use the correct GHG metric. I did not calculate the impact of these additional factors on facility emissions due to time constraints and incomplete information in the permit record. However, their incorporation would significantly increase the emissions shown in this table, which should be considered as the lower end of the range of emissions from equipment leaks.

The Application's emissions were based on the TCEQ "without ethylene" emission factors for SOCMI "chemical plants," which yield total emissions of 342 ton/yr. This is lower than estimated using all other more representative emission factors. These include two other sets of emission factors for "chemical plants" — the average USEPA SOCMI emission factors (535 ton/yr) and the TCEQ "with ethylene" SOCMI emission factor (866 ton/yr). The highest total emissions from equipment leaks occur when the USEPA average refinery emission factors (1,364 ton/yr) are used.

Gasification plants are more similar to refineries than chemical plants. They both, for example, convert fossil fuels (petroleum, coal) into end products used to generate fuels (gas, gasoline) under similar conditions of pressure and temperature. They both also use many of the same unit operations, including sour water stripping, sulfur recovery, tailgas treating, sulfur tank and loading, sulfur recovery, thermal oxidizers, and acid gas removal systems.[144]

This underestimate is important. The application concluded that no controls were cost-effective for equipment leaks and eliminated them all as BACT. However, cost-effectiveness is just the annual cost-per-ton of pollution removed. If the tons of pollution removed are underestimated, as here, the cost per ton is overestimated. When the revised emissions shown above in Table 9 are used to calculate cost-effectiveness, leakless technology and plant-wide LDAR are both cost-effective for the TEC.

This underestimate is also important because the total emissions summarized in Table 9 were used to calculate the amount of each regulated PSD and HAP pollutant (*e.g.*, CO, VOM, CO_2, methanol, etc.). Because the starting point, the total emissions, was underestimated, all of the individual pollutants calculated therefore were also underestimated. This results in a chain reaction of problems, from erroneously rejecting technologies based on cost, to excluding H_2S and reduced sulfur compounds from PSD review, to concluding that the TEC is a minor source for HAPs. These problems are discussed further below.

[144] Compare Ap., v. 1, Fig. 1-1 and process descriptions in Sec. 2.2 to, *e.g.*, Robert A. Meyers, Handbook of Petroleum Refining Processes, 3 Ed., McGraw-Hill, 2004; Surinder Parkash, Refining Processes Handbook, Elsevier, 2003; James H. Gary and Glenn E. Handwerk, Petroleum Refining Techno10y and Economics, 4th Ed., CRC Press, 2001, 1984; James G. Speight, Synthetic Fuels Handbook. Properties. Process, and Performance, McGraw-Hill, 2008; Christopher Higman and Maarten van der Burgt, Gasification, 2nd Ed., Elsevier, 2008.

Second, this table shows that connectors are the major source of emissions from equipment leaks. The Application excluded connector leaks from its BACT analysis under the theory that their emission factor (lb/hr per connector) was only 70% of the emission factor for other components. However, the Application failed to consider that there are many more connectors in the facility than any other component, so when total connector emissions are calculated from lb/hr per connector times the number of connectors, the contribution of connectors to total emissions is substantial. Thus, the BACT analysis for equipment leaks is fundamentally flawed as it rejected leakless connectors, *i.e.*, welds, as not cost-effective without even including them in the cost analysis.

For the reasons presented in the application and discussed further, the potential emissions for equipment leak components in the draft permit are appropriate and conservative. Emissions factors developed for refineries are not appropriate for the many reasons presented previously, including the comment's own statements.

39. The Application concluded that PSD review is not triggered for TRS (total reduced sulfur) or H_2S as source-wide potential emissions (8.78 ton/yr) are less than the PSD significant emission rate of 10 ton/yr.[145] This conclusion is wrong based on the application's own emission estimates, as explained in my comments. In addition, my revised emission calculations for equipment leaks confirm that the significant emission rate is exceeded for all three reduced sulfur PSD pollutants. Emissions of these PSD pollutants from equipment leaks were underestimated due to the use of the TCEQ "without ethylene" emission factors for chemical plants, as discussed above. In addition, COS was erroneously excluded from emissions of total reduced sulfur (TRS) and reduced sulfur compounds (RSC) as will be addressed in other comments generally addressing the approach that was taken to TRS and RSC. These two errors are corrected in the summary emissions in Table 10. This table shows that PSD review is triggered for H_2S, TRS, and RSC.

For the reasons presented in the application and further discussed in this document, the calculations for potential emissions for equipment leak components are appropriate and conservative. Furthermore, CCG correctly interpreted the regulatory definitions for the PSD pollutants "reduced sulfur compounds" and "total reduced sulfur" as will be discussed later.

40. The emissions for equipment leaks are underestimated because of the approach that was taken for the control efficiency of the required Leak Detection and Repair (LDAR) Program. An LDAR program is proposed to control equipment leak emissions from a subset of the components - 3,664 components comprising 15% of the total of 24,979 components. An LDAR program reduces emissions compared to the uncontrolled levels by finding and repairing leaks. The Application concluded that an LDAR program as BACT is "cost infeasible," but stated that it plans to implement a "MACT-equivalent LDAR program for components in high VOM service in order to reduce VOM emissions by more than 90 percent and 26 tpy."[146] However, the Application itself does not define what it means by "MACT-equivalent." I studied the supporting emission calculations in the Application's

[145] Ap., v. 1, p. 4-6, Table 4-1.
[146] Ap., v. 1, p. 6-42.

appendices and conclude that the Draft Permit does not require the LDAR program required to achieve the control efficiencies used in the emission calculations. Further, there is nothing in the Draft Permit to ensure that the installed component and LDAR program will actually achieve the assumed control efficiencies.

The equipment leak emissions were underestimated by assuming much higher control efficiencies for LDAR than required by the Draft Permit. The control efficiency is an estimation of how successful the leak detection and repair program is at finding and fixing leaks. The emission calculations assume a 97% control efficiency for all components except certain pumps, which means only 3% of the emissions remain, compared to what would normally be leaking into the atmosphere if there was no LDAR program.

The control efficiencies used in the Application were taken from draft TCEQ permitting guidance that is based on certain assumptions about how the LDAR program is carried out, *e.g.*, testing frequency, leak detection threshold, time to repair, excluded components. These draft TCEQ control efficiencies are unsupported, were not carried over into final guidance,[147] and differ substantially from estimates published by USEPA. Further, the Draft Permit fails to require the same level of monitoring assumed in the draft TCEQ guidance to achieve these efficiencies.

Emissions from equipment leaks were calculated by multiplying the uncontrolled emissions by a control efficiency based on the implementation of a LDAR program. The uncontrolled emission factors were calculated from measurements made in chemical plants that did not monitor these emissions. Equipment leak emissions can be reduced by monitoring the components and repairing them when a leak is found. The amount of emission reduction that can be achieved depends on the frequency and method of measurement or observation, the length of time between leak detection and repair, and definition of a leak, *e.g.*, the concentration in parts per million ("ppm") at which a leak is assumed to occur.

The application picked the most aggressive control efficiencies that have been proposed anywhere for any type of facility and applied them across the board. The LDAR program must be designed to assure that the assumed control efficiencies are achieved in practice. However, the LDAR program in the Draft Permit is not consistent with the assumptions underlying the assumed control efficiencies.

The comment correctly points out that an LDAR program will only be implemented on a subset of components at the TEC that are in high-VOM concentration service. Condition 4.9.2(a)(i) of the permit specifically identifies the components to which the LDAR program will apply, and Conditions 4.9.6 through 4.9.9 detail all of the monitoring, recordkeeping, and reporting requirements that the TEC must implement to achieve the LDAR control credits identified in the Application. The term "MACT-equivalent" with reference to the proposed LDAR program in the Application simply means that the LDAR program selected for the TEC has similar leak detection thresholds, monitoring frequencies, and repair requirements to the LDAR programs included in 40 CFR Part 63, such as 40 CFR 63 Subparts H, TT, and UU.

[147] Texas Committee on Environmental Quality, Emission Factors for Equipment Leak Fugitive Components, January 2008; http://www.tceg.texas.ov/assets/public/implementation/air/ie/pseiforms/ef elfc.pdf, (Commenter's Exhibit 44)

The comment claims that the Draft Permit would not require the LDAR program envisioned in the Application. This is not accurate since Conditions 4.9.6 through 4.9.9 mirror the exact language of the TCEQ LDAR programs referenced in conjunction with the control credits. Specifically, TCEQ's equipment leak guidance document contains the required permit language for the 28VHP and 28CNTQ LDAR programs. These programs and the control credits they offer (refer to pages 52 and page 16 of the TCEQ equipment leak guidance document) were referenced in Section C-24 to C-27 of Appendix C to Volume 1 of the Application. The permit language from these two programs was included in Exhibit 391-7 to the 391-CAAPP application form required by the IEPA for construction permit applications to document the fugitive emissions data and information presented in the application. The IEPA used this application form as a reference when developing the Draft Permit, and a simple comparison of the Draft Permit to the relevant LDAR program language in the TCEQ guidance document reveals the requirements of the LDAR programs in these two documents are nearly identical with a few limited exceptions discussed later in this response. In issuing GHG permits for facilities in Texas, USEPA Region 6 has relied on the LDAR control credits in the TCEQ ELC permitting guidance for demonstrating compliance with GHG BACT limits.[148]

Beyond simply requiring CCG to implement an LDAR program, the permit establishes explicit BACT limits in Condition 4.9.2(d) and corresponding actual emissions recordkeeping requirements in Condition 4.9.7(c). The comment's suggestion that CCG is not required to demonstrate compliance with these BACT limits based on implementing the LDAR program and tracking actual emissions is incorrect. During each round of instrument monitoring, CCG will generate a measured concentration of VOC at the leak interface of each monitored component which can be used in conjunction with USEPA's screening ranges or correlation emission factors in Tables 2-5 and 2-9 of the Equipment Leak Protocol and assumptions about stream composition to estimate actual annual VOC emissions. Using measured data (where available) will provide the most accurate estimate of VOC emissions from the TEC for comparison against permit limits, and these calculations will ensure that CCG is achieving at least as high of a control credit as was envisioned in the Application. The comment appears to suggest that CCG would replicate the potential emission calculations in the Application as the basis for demonstrating compliance with the BACT limits, which reflects a fundamental misunderstanding of how actual fugitive ELC emissions from chemical plants are quantified in practice.

The comment also questions the basis of the TCEQ control credits by stating that these control credits were never included in what they claim is the final version of the equipment leak guidance document. The TCEQ document entitled *Emission Factors for Equipment Leak Fugitive Components* included as Commenter's Exhibit 24 is not a final version of the *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives* included as Commenter's Exhibit 23. Commenter's Exhibit 23 is the primary reference document used by CCG as the basis for the SOCMI without ethylene emission factors and the LDAR control credits, not Commenter's Exhibit 24.

[148] USEPA Region 6, PSD Permit for Greenhouse Gas Emissions, March 21, 2012, available at http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/etc_jackson_draftpermit.pdf

A cursory review of the generally unrelated Commenter's Exhibit 24 reveals that its purpose is not to provide guidance for how best to permit fugitive equipment leak emissions but how to quantify actual emissions for annual emission inventory reporting purposes. The reason that LDAR control credits are not included in this document is TCEQ does not allow facilities to use these control credits in calculating actual emissions from ELC monitored as part of an LDAR program. Instead, actual emissions determinations for ELC monitored as part of an LDAR program must be determined using site-specific monitoring data and USEPA correlation equations. CCG must follow this same or a similar practice when demonstrating compliance with the BACT limits in the permit as discussed further below.

Similar to statements made regarding the aggressiveness of the SOCMI without ethylene factors, the comment claims that the 28VHP and 28CNTQ LDAR program control credits referenced in the TCEQ guidance document and used to establish emissions estimates for the TEC are "the most aggressive control efficiencies that have been proposed anywhere for any type of facility." This statement is not supported, and is not true when all of the chemical plants in Texas subject to these LDAR programs would apply these control credits when quantifying potential emissions from ELC in construction permit applications. Furthermore, similar coal gasification facilities located outside of Texas which recently received air permits have used these very same control credits to estimate emissions and establish their BACT limits including Kentucky Syngas and Indiana Gasification.[149] [150] CCG acted consistently with countless chemical facilities in Texas and recent coal gasification projects to establish a stringent **and enforceable LDAR program for inclusion in the permit, and the compliance demonstration requirements in the permit will assure that the control credits assumed in the derivation of the BACT limits will be achieved in practice.**

41. The control efficiencies used for the planned LDAR program are not supported. I was unable to find any support for the assumed control efficiencies. TCEQ personnel informed us that "the original work was done in the mid-80s and there is no formal documentation of the basis in guidance documents."[151] Monitoring studies conducted in Texas have conclusively documented that Texas emission inventories consistently underestimate emissions from leaking components by significant amounts. *See* studies cited *supra.* Thus, barring evidence produced in response to this comment, CCG should not be allowed to use these control efficiencies to calculate emissions.

While this comment claims that it was unable to find any support for the assumed control efficiencies for the TCEQ LDAR programs referenced in the equipment leak guidance document, but discussions with TCEQ staff provided in Commenter's Exhibit 25 explain and justify the basis for the development of these factors. The comment cites a single sentence from the three page email discussion with TCEQ to suggest that TCEQ staff do not know the basis for the LDAR control credits used by all chemical plants in the state and referenced in their current equipment leak permit

---

[149] **Kentucky Division for Air Quality,** ***Final Air Quality Permit Issued Under 401 KAR 52:020 for Kentucky Syngas, LLC,*** **September 24, 2010, available at http://dep.gateway.ky.gov/eSearch/.**

[150] **Indiana Gasification,** ***Indiana Gasification, LLC PSD Air Permit Application Indiana SNG Project,*** **April 20, 2011.**

[151] Email from Texas Commission on Environmental Quality to Phyllis Fox, December 13, 2011.

guidance document.[152] This characterization of the email is incorrect and misleading. In the same email chain, not mentioned by the comment, TCEQ explains the basis and rationale for the control efficiencies suggested in the guidance. The out-of-context quote highlighted in the comment simply indicated that TCEQ did not publish "formal" documentation of the basis. The quote goes on to say: "There *IS* an interoffice memo dated April 13, 1995 which documents the basis… [Emphasis added]."[153]

TCEQ also emailed an electronic copy of their presentation material from the 1994 Air Permits Workshop, which outlined the development of the factors and guidance document. The comment failed to provide this document as an exhibit to their comments even though it can be used in conjunction with the TCEQ email chain in Commenter's Exhibit 25 to show the derivation of the LDAR control credits for certain component types. In the 12/13/11 12:43 PM email from Dana Poppa Vermillion of TCEQ to Randy Hamilton of TCEQ, she states "the control efficiencies used with the 500 ppmv leak definition are based on the percent difference between the SOCMI average factors and the Stratified factors."[154] Conditions 4.9.6(h) and (j) of the Draft Permit establish a leak definition of 500 ppmv for valves and connectors which allows CCG to assume a 97% control credit for these component per TCEQ guidance.

Beyond this clear oversight of ignoring the 1994 air permit seminar document, it is also incorrect and misleading to state "we are unable to find any support for the assumed control efficiencies" based only on a review of the information in Commenter's Exhibit 25. In the TCEQ email chain, the TCEQ staff specifically supports the use of the guidance document, noting "the [SOCMI without ethylene] factors have been in use since 1986 when the agency began including piping fugitives in permits", "the control factors [i.e., LDAR control credits] have been in use since 1986," and "the technical information contained in the guidance document has not changed and is still used even though the document remains in draft form."[155] The support for these factors and control programs is not limited to Texas, nor restricted only to a very narrow industry

---

[152] **Comment Exhibit 25 p. 3.**

[153] **Comment Exhibit 25 p. 3**

[154] **To verify the context of the discussions between Phyllis Fox and TCEQ regarding the TCEQ equipment leak guidance and to obtain more information about how this guidance document is used today, CCG held a conference call with Ms. Dana Poppa-Vermillion of TCEQ on January 30, 2011. During this call, Ms. Poppa-Vermillion explained that she was not aware that Phyllis Fox represented the Sierra Club and that the email exchange was all she remembered about their communications. She explained that the TCEQ equipment leak permitting guidance document is used ubiquitously throughout the state by any plant seeking a construction permit, and that SOCMI without ethylene factors are used for any chemical plant in the state that has process streams containing less than 11% ethylene.**
In follow-up to this call, Randy Hamilton with TCEQ provided the document entitled *Air Permit Seminar 1994 Fugitives* which was included as an attachment to the 12/9/11 3:54 PM email from TCEQ to Phyllis Fox, but was not provided with the final exhibits supporting the Sierra Club and Natural Resources Defense Council (NRDC) comment letter. On page 12 of this document, TCEQ presents a table comparing the SOCMI average, SOCMI without ethylene, SOCMI with ethylene, stratified 0-1,000 ppm, and non-leaker ELC emission factors. Based on the TCEQ statement regarding the derivation of control credits for components subject to a leak detection threshold of 500 ppm cited above, the 97% control credit applied to gas/vapor valves can be derived by simply taking the percent difference of the SOCMI average and stratified 0-1,000 ppm factors on page 12 of the 1994 air permit seminar document [e.g., (0.0123 lb/hr/component for SOCMI average – 0.00031 lb/hr/component) / 0.0123 lb/hr/component for SOCMI average = 97%]. Similar derivations apply to the other types of components for which the 97% control credit is applied. The logic behind TCEQ's method for deriving LDAR program control credits is that components subject to an LDAR program at a 500 ppm leak definition would have a leak rate in aggregate across a facility or process unit at or below the 1-1,000 ppm stratified factor and a uncontrolled facility would have a leak rate equivalent to the SOCMI average factor. SOCMI without ethylene factors are not used in this derivation because the stratified factors are based on the entire SOCMI dataset and not just the facilities with little to no ethylene in their process streams. The same relationship between uncontrolled and stratified factors observed for the entire SOCMI dataset would also hold true for the subset of the SOCMI dataset addressing facilities with low concentrations of ethylene.

[155] **Commenters' Exhibit 25, pp. 1 and 3.**

group. As further elsewhere, there are other examples of draft guidance being relied upon for air permitting when a final does not exist, and there are several examples of many state agencies finding that the factors and control from TCEQ's dataset is appropriate for gasification facilities.

Also described elsewhere, the monitoring studies conducted in Texas for which the comment asserts "conclusively documented that Texas emission inventories consistently underestimate emissions from leaking components" are not relevant to the TEC permit. These studies were conducted on a macro scale for refineries, which are far different than the proposed facility. Using a macro-level, optical scan of total fugitive emissions from a refinery cannot be directly compared to emissions measured from a specific ELC type, and certainly cannot "conclusively" make a determination that direct source sampling is somehow less representative.

42. Lower control efficiencies should apply for the LDAR program. The USEPA has published control efficiencies for LDAR programs based on monitoring data and established control efficiencies as part of rulemakings. These efficiencies are lower than the efficiencies used by CCG in the emission calculation in the Application. [156]

The comment provides a summary table of LDAR control efficiencies for different LDAR programs to provide a comparison to the control efficiencies utilized in the derivation of the BACT limit for components in VOM service at the TEC. Of particular relevance in this table are 1) The frequency of inspection, and 2) The leak detection threshold for each LDAR program. As such, a direct comparison of the program control efficiencies is not provided. Further information would be necessary before a meaningful comparison between the TEC's LDAR control credits and USEPA's control credits in the Equipment Leak Protocol can be made.

Pursuant to Condition 4.9.6(c), all valves for process streams listed under Condition 4.9.2(a)(i) must be monitored using an approved gas analyzer on a quarterly basis at a leak detection threshold of 500 ppm [refer to Condition 4.9.6(h)]. The comment mistakenly treats heavy liquid valves as somehow different from gas/vapor and light liquid valves when in fact they will be monitored according to the same frequency and leak detection threshold as gas/vapor and light liquid valves. Per footnote 4 to the TCEQ LDAR control credit summary table (refer to page 58 of 60 of Commenter's Exhibit 23), valves in heavy liquid service may be given a 97% control credit if they are monitored at 500 ppmv by permit condition (provided that the concentration at saturation is greater than 500 ppmv). As discussed further elsewhere, the saturation concentration criteria is met for all heavy liquid valves that will be included in the LDAR program. Condition 4.9.6(c) requires leak monitoring for all valves and not just those in gas/vapor or light liquid service, and therefore, the approach for handling heavy liquid valves in the permit is consistent with TCEQ guidance.

[156] Summarized from USEPA 1995, Commenter's Exhibit 21., Table 5-3 and TCEQ 10/00, pp. 52-5353, Commenter's Exhibit 19, Tab Cont Eff

Similar to valves, Condition 4.9.6(g) requires all pump and compressor seals on process streams identified in Condition 4.9.2(a)(2)(i) to be monitored on a quarterly basis using a leak detection threshold of 2,000 ppm regardless of service type. No exclusion from heavy liquid pump monitoring is made in the permit. As shown in Section C-24 of Appendix C to Volume 1 of the Application, CCG used a 93% control credit for 4 heavy liquid pumps in TEG service within the Gasification/Syngas Conditioning/Methanation process area (designated as ELC1 in the Application). In accordance with footnote 6 to TCEQ's LDAR control credit summary table (refer to page 58 of 60 in Commenter's Exhibit 23), pumps in heavy liquid service may be given a 93% control credit if monitored at 500 ppm by permit condition (provided that the concentration at saturation is greater than 500 ppmv). As discussed further elsewhere, the saturation concentration criteria is met for all heavy liquid pumps that will be included in the LDAR program. Condition 4.9.6(h) of the Draft Permit currently states the following with respect to the pump leak detection threshold:

> **Damaged or leaking pump, compressor, and agitator seals found to be emitting VOM in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired.**

The issued permit in Condition 4.9.6(h) clarifies that pumps in heavy liquid service are subject to a leak detection threshold of 500 ppm so that the LDAR control credit applied to heavy liquid pumps will be appropriate based on the requirements of the issued permit and TCEQ's equipment leak permitting guidance.

Pursuant to Condition 4.9.6(j), connectors in gas/vapor and light liquid service on process streams identified in Condition 4.9.2(a)(i) must be monitored on an annual basis using a leak detection threshold of 500 ppm. Two updates were made to the issued permit to match the LDAR control credits assumed in Sections C-24 to C-27 of Appendix C to Volume 1 of the Application. First, the monitoring frequency was changed to quarterly to reflect the use of the 28CNTQ control credits in the TEC's emission calculations. Second, the 148 heavy liquid connectors in TEG service identified in Section C-24 of Appendix C for which a 97% control credit was applied were included in the quarterly connector monitoring requirement. As described in footnote 7 to TCEQ's LDAR control credit summary table (refer to page 58 of 60 to Commenter's Exhibit 23), if an applicant decides to monitor connectors using an organic vapor analyzer (OVA) at the same leak definition as valves, then the applicable valve LDAR control credit can be used instead of the 30% control credit offered for weekly physical inspections. If this option is chosen, however, weekly physical inspections must be performed in addition to the quarterly OVA monitoring. CCG will conduct weekly physical inspections and quarterly OVA monitoring for all connectors on process streams identified in Condition 4.9.2(a)(i), and therefore, a 97% control credit was appropriately applied for connectors in all service types included in the LDAR program. Withthe noted updates to the issued permit , the LDAR control credits applied in the emission calculations and the associated monitoring requirements in the permit necessary to claim these credits are consistent.

Pursuant to Condition 4.9.6(k) of the Draft Permit, open-ended valves or lines are required to be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. While the TCEQ equipment leak guidance would allow a 100% control credit for open-ended lines that are equipped with a cap, blind flange, or second valve to seal the line (refer to footnote 8 to the TCEQ LDAR control credit summary tables on page 58 of 60 in Commenter's Exhibit 23), CCG conservatively assumed that all open-ended valves or lines subject to the LDAR program may not be equipped with caps, blind flanges, or a second valve at all times, and therefore would be subject to the quarterly equipment leak monitoring requirements applicable to valves. As such, applying a 97% instead of a 100% control credit in the TEC's emission calculations was appropriate and conservative, since CCG does not expect to operate any open-ended lines without the requisite cap, blind flange, or second valve.

Under the TCEQ LDAR program scheme, sampling connections are treated in the same way as valves, so the LDAR control credits for sampling connections are the same as valves. To clarify that sampling connections on process streams identified in Condition 4.9.2(a)(i) are subject to the quarterly valve monitoring requirement in Condition 4.9.6(c), Condition 4.9.6(c) was changed in the issued permit to include both valves and sampling connections.

With a firm basis established for all control credits assumed in the ELC emission calculations and adequate references to the requirements of the permit which justify the use of these control credits, the comment's comparisons to control credits cited by USEPA can be addressed in further detail. Under 40 CFR Part 63 Subpart H (commonly referred to as HON), gas/vapor and light liquid valves are subject to quarterly monitoring with leak detection thresholds that ratchet down from 10,000 ppm to 500 ppm based on a phased implementation schedule [refer to 40 CFR 63.168(a) and (b)]. HON also allows facilities to skip monitoring periods to every 2 quarters or every 4 quarters depending on the percentage of leaking components identified during previous rounds of monitoring [refer to 40 CFR 63.168(d)]. The LDAR program selected for the TEC requires quarterly monitoring with no "skip period" alternative as allowed under HON. The increased stringency of the TEC's LDAR program with respect to leak detection threshold and monitoring frequency as compared to HON is more than adequate to justify an increase in LDAR control credits from 96% to 97% for gas/vapor valves and from 95% to 97% for light liquid valves. It is also difficult to imagine how the comment can claim the 97% LDAR control credit for valves is the most aggressive control credit that has been proposed anywhere at any type of facility when USEPA established very similar control credits for the less stringent HON rule more than 15 years ago. For heavy liquid valves, HON only requires leaks to be repaired if evidence of a potential leak to the atmosphere is found by audible, visual, or olfactory (AVO), or any other detection method with no requirement to conduct routine inspections of any kind on these components (refer to 40 CFR 63.169). Essentially, the only requirement in HON for heavy liquid valves is to fix any leaks that are identified through AVO means when operators are in the field conducting instrument inspections on other types of components or during the normal course of their work. As such, USEPA did not establish a control credit for heavy liquid pumps under HON. In contrast, CCG is required to conduct quarterly

monitoring of heavy liquid valves at a very low leak detection threshold of 500 ppm. With the same monitoring scheme applied for all valves regardless of service type, applying a single LDAR control credit of 97% for all valves subject to the LDAR program is appropriate and justified based on the terms and conditions to be included in the issued permit.

The LDAR control credit applied by CCG for light liquid pumps is 85% as compared to the HON control credit from USEPA of 88%. CCG is required to conduct quarterly instrument monitoring for pumps using a leak detection threshold of 2,000 ppm, while HON requires monthly instrument monitoring with a phased-in leak detection threshold decreasing from 10,000 ppm to 2,000 ppm [refer to 40 CFR 63.163(b) and 40 CFR 63.163(c)(3)]. Based on the differences in monitoring frequency and leak detection threshold for these two LDAR programs, it was reasonable and appropriate for TCEQ to establish a LDAR control credit of 85%. For heavy liquid pumps, CCG will be required to conduct quarterly monitoring at a leak detection threshold of 500 ppm or 4 times lower than the HON leak definition for light liquid pumps. Similar to heavy liquid valves, HON does not require any type of routine inspection for heavy liquid pumps, so the HON cannot be used as a reference for determining the appropriateness of the TEC's heavy liquid pump LDAR control credit. Using a slightly higher control credit for heavy liquid pumps in comparison to light liquid pumps (i.e., 85% for light liquid valves and 93% for heavy liquid valves) is appropriate in light of the much more stringent leak definition for heavy liquid pumps that will be included in the issued permit.

For all connectors regardless of service type, USEPA established a HON control credit of 81%. HON requires gas/vapor and light liquid connectors to be monitored on an annual basis using a leak definition of 500 ppm (refer to 40 CFR 63.174). Once corrected, Condition 4.9.6(j) in the Issued Permit will require CCG to conduct quarterly monitoring at a leak detection threshold of 500 ppm. Both the HON and the permit reference skip period alternatives in 40 CFR 63.174(b)(iii) through (v) [refer to Condition 4.9.6(j)], so this element of the LDAR program cannot be used to differentiate the HON control credit from the TEC control credit. HON also does not require any type of routine inspections for connectors in heavy liquid service, so the HON control credit for connectors in all service types represents some kind of weighted average of a zero percent control credit for heavy liquid connectors and presumably a relatively high control credit for gas/vapor and light liquid connectors subject to annual monitoring. With such significant differences between how the HON control credit was derived and how the service-type specific TEC control credits apply, it is difficult to make a meaningful comparison between these two values. Regardless, CCG must conduct quarterly monitoring at a leak detection threshold of 500 ppm for all connectors on process streams identified in Condition 4.9.2(a)(i), and has applied a reasonable control credit of 97% for these very stringent monitoring requirements.

No HON control credits are provided by USEPA for open-ended lines and sampling connections since these components are not subject to periodic instrument monitoring. If not equipped with caps, blind flanges, or second valves, CCG will treat open ended lines as valves for the purposes of LDAR monitoring and apply the appropriate LDAR

control credit to reflect this practice. Finally, as discussed above sampling connections will be treated like valves for the purposes of LDAR monitoring as reflected in the issued permit.

In summary, CCG is subject to a LDAR program that is at least as stringent and in many cases more stringent than the federal HON LDAR program commonly applied at most chemical facilities. A detailed comparison of the monitoring requirements between HON and the selected LDAR program for the TEC reveals that in any instances where the control credit applied by CCG is higher than the HON control credit referenced by USEPA there are clear differences in the two programs that can be cited as justification for these differences.

43. Control efficiencies are overestimated for all fugitive components because the conditions in the Draft Permit would not be adequate to assure that the aggressive control efficiencies in the application are achieved in practice. One would need a combination of the following in order to achieve high control efficiencies and to confirm emission limits:

— An assessment of BACT for fugitives including installation of sufficient numbers of leakless components, without exemptions for monitoring of these components;

— An audit of the actual leak rates of the facility to compare to those initially assumed, and to develop site specific control efficiencies;

— Limits on the number of inaccessible, difficult-to-monitor, and unsafe-to-monitor components, inclusion of more reasonable, low control efficiencies for these, specific requirements that leaks be fixed at the next turnaround or earlier time period, and inclusion of emissions from these components in total emissions;

— A feedback system to ensure that the when the LDAR program detects any leaks, the emissions are included in the total permit limits rather than using pre-determined emissions calculations for in compliance determination.

The draft permit does not provide for any of the above actions or systems. Consequently, it provides no assurances that the high control efficiencies assumed will be met.

The comment asserts that the conditions in the draft permit are not adequate to ensure correct LDAR control. They suggest four specific work practices should also be utilized to justify the control efficiencies established for the high VOM streams controlled through the LDAR program included in the draft permit.

In general, it should be reiterated that the LDAR requirements of the draft permit were patterned after NESHAP regulations and TCEQ's 28VHP program, which through its stringent requirements support the claimed control credits. The IEPA did not re-create a unique LDAR program that is independent of the required control efficiencies in the draft permit. Instead, the stringent permit LDAR requirements represent a robust monitoring and recordkeeping program that is specifically correlated with the control efficiencies associated with the work practices established

as BACT for the high VOM stream ELC. The LDAR program included in the permit is not a one-off program with fabricated LDAR requirements, but rather, any chemical facility in the state of Texas subject to the commonly applied requirements of the 28VHP and 28CNTQ LDAR programs would have very similar LDAR program requirements in their permit. In addition, the Kentucky Syngas SNG-production facility is required to implement a very similar LDAR program to that included in the permit. The LDAR requirements are consistent with the compliance methodology that is routinely approved for other similar facilities, and are supported through specific guidance, precedent, and supportive data analysis.

On the other hand, the comment's suggestions are baseless and without correlation to the reduction credits associated with the BACT control for the high VOM streams. Each specific suggestion is inappropriate for the reasons discussed individually below.

1. **The comment claims that an assessment of leakless components should be included in the BACT analysis, and that following installation, the leakless components should not be excluded from the LDAR monitoring requirements. CCG did include an assessment of leakless components in the Application and the IEPA summarized the conclusions of this analysis in the Project Summary. Leakless components were evaluated as the top control technology in the BACT analysis for ELC, but installing leakless components was not cost effective. The economic analysis used to demonstrate the cost ineffectiveness for leakless components conservatively assumed that leakless components achieved 100% control without further monitoring. Consideration of LDAR on top of leakless components would only add expense without additional reduction credit applied, exacerbating the already high annual control cost determined for this technology. Requiring LDAR for leakless components would serve as a disincentive for the installation of leakless technology – which as the name suggests, are designed not to leak. Many LDAR programs are designed accordingly, and specifically exempt leakless components from monitoring requirements. For example, USEPA exempts leakless pumps and connectors from monitoring under the HON LDAR program.[157]**

2. **The second additional requirement that the comment suggests is necessary is that an audit of the actual leak rates of the TEC must be conducted to compare to those initially assumed, and that this information should then be used to develop site-specific control efficiencies. Permit Condition 4.9.5 requires CCG to demonstrate compliance with ELC emission limits using an appropriate USEPA methodology. This appropriate methodology could include any of the approaches defined in USEPA's *Protocol for Equipment Leak Emissions Estimates*, which include the Screening Ranges Approach and the Correlation Approach. Using one of these possible approaches would be expected to result in lower emissions estimates for equipment leak components than estimated in the Application and included as BACT limits in the Draft Permit. For each round of instrument monitoring, TEC will develop entirely new emissions**

[157] **40 CFR 63.163(f) and 63.174(j).**

factors that incorporate actual monitoring results. The fixed SOCMI without ethylene emission factors have been developed by TCEQ only for the purposes of quantifying the potential to emit of ELC's at a particular source in a pre-construction permit application. These factors provide conservative estimates for actual equipment leak emissions from new chemical facilities because they are based on data collected from existing facilities in the 1980s which would be expected to have much older components with higher leak rates (as discussed previously). Once the facility is operating and an initial round of instrument monitoring data has been collected, the leak/no-leak data or measured concentrations could be used in conjunction with the screening ranges or correlation emission factors in Table 2-5 and 2-9 of the Equipment Leak Protocol to estimate actual emissions. For existing components subject to LDAR, the TCEQ SOCMI without ethylene emission factors and LDAR control credits applied in the Application will never be used again. The comment seems to think that CCG will be using LDAR control credits as part of the compliance demonstration calculations for the ELC BACT limits when this is clearly not the case in light of USEPA and TCEQ guidance about how best to quantify actual emissions from an operating chemical plant. References to developing site-specific control efficiencies by the comment are meaningless and reflect a fundamental misunderstanding of equipment leak emission estimates. For a facility to determine the emissions reductions offered by implementing an LDAR program, the facility would have to first operate for a prolonged period without an LDAR program and somehow quantify emissions during this period. Then, the facility would have to implement an LDAR program and use the "controlled" emission calculations from USEPA's screening ranges or correlation emission factors for comparison against the uncontrolled emission rate. Such an intensive study may be appropriate for USEPA or a state air agency in a rule development context, but this type of study could not be implemented at a facility subject to stringent BACT limits that reflect the use of an LDAR program at all times.

Furthermore, conducting actual measurements of emissions from leaking components (through bag sampling) to develop a site-specific correlation equation between screening value and emission factor is not appropriate or necessary. USEPA does not support the use of "rigorous" direct measurement when existing correlations are already available and appropriate, as is the case for the TEC (i.e., the SOCMI correlation emission factors should be representative for all of the same reasons that the SOCMI without ethylene factors were determined to be representative for the TEC's equipment leak components).[158] It would be an extremely burdensome requirement to conduct an intensive sampling/bagging analysis of all equipment leak components at the facility and would be prohibitively expensive, offering no additional environmental benefit for a brand new facility. USEPA only addresses sampling/bagging as a means for initial emission factor development (as conducted by USEPA), but does not identify it as an appropriate method for

[158] **Commenter's Exhibit 21, see p. 4-1.**

emissions calculations conducted for compliance verification. The inappropriateness of sampling/bagging is supported in that no other agency or permit was identified as requiring this activity for a permitted source.

3. **The third suggestion for justifying the reduction credits of the stringent LDAR requirements of the permit is that the permit should limit inaccessible, difficult-to-monitor, and unsafe-to-monitor components. Condition 4.9.6(a) specifically limits inaccessible, difficult-to monitor, and unsafe-to-monitor components. The emission factors for SOCMI without ethylene equipment leak components, and the control efficiencies based on TCEQ's 28 VHP LDAR requirements are derived from a significant dataset of existing facilities that would inherently include a representative number of inaccessible components that are common to complex chemical facilities. As such, these factors and control efficiencies are not meant to be constrained to only "accessible" components, and should not be construed to represent the expected emissions from a single component. Instead, the factors and control efficiencies represent the emissions and control that can be expected across all of a facility's components.[159] USEPA specifically identifies that the SOCMI average emission factors must be used for difficult or unsafe to monitor equipment components, just as was done by CCG in the Application. From a compliance demonstration method standpoint, if an inaccessible component is not monitored during a given round of instrument monitoring, CCG will have no choice but to use the SOCMI without ethylene factors for this component with either no control credit or a reduced control credit applied to account for any monitoring that may have been done within the past calendar year.**

   The comment further suggests that the permit should include specific requirements that leaks are fixed at the next turnaround or earlier time period. Condition 4.9.6(i) specifically addresses this suggestion. These "delay of repair" provisions are consistent with the TCEQ 28 VHP LDAR program, and thus support the use of the control efficiencies, as applied. Furthermore, Condition 4.9.6(i) requires CCG to quantify emissions from all components on the delay of repair list between the date they are put on delay or repair and the next process unit shutdown. If the aggregate emissions rate from these leaking components exceeds the total emissions from a shutdown, CCG is required to notify the IEPA, and the IEPA may require an early process unit shutdown or other alternative actions to minimize emissions from components on the delay of repair list.

4. **The comment's final suggestion is that the LDAR requirements should include a feedback system, or a tracking system to account for emissions from identified leaking components, and this emission accounting should be the methodology utilized to compare to the emissions limitations from equipment leak components. As described in the response to the comment's second suggestion, above, Condition 4.9.5 of the permit includes a requirement that the TEC verify**

[159] **Commenter's Exhibit 21, see pp. 2-17 and 2-51.**

compliance with the emissions limits using appropriate USEPA methodology. Possible approaches for estimating emissions from leaking components include USEPA's Screening Ranges Approach or the Correlation Approach. The Screening Ranges Approach relies on leak-no leak information for each component subject to periodic monitoring under the LDAR program and uses this data in conjunction with separate leaking and non-leaking emission factors to predict actual emissions from equipment leak components.[160] Since USEPA's SOCMI screening ranges or "leak-no leak" emission factors are based on a leak detection threshold of 10,000 ppm for all component types and CCG is subject to leak detection thresholds of either 500 or 2,000 ppm depending on component and service type, the screening ranges approach would likely over predict actual emission from the TEC, and therefore, would not be preferred. The more accurate and refined Correlation Approach allows for an estimate of emissions as a function of the screening value for the particular component type over the entire range of screening values from 0 ppm to 1,000,000 ppm.[161] By including these USEPA approaches, Condition 4.9.5 does provide a "feedback" system to account for emissions from identified leaking components.

The issued permit does provide assurance that the high control efficiencies assumed in the Application and used in the derivation of the BACT limits will be met in practice by requiring CCG to implement a very stringent LDAR program. Furthermore, the comment is not correct that the permit does not provide for any of their recommendations. As noted in the specific responses to each of the four suggestions, the permit does include appropriate requirements for emissions verification, and several specifically address the comment's suggestions.

44. Control efficiencies for connectors are overestimated. The equipment leak emission calculations in the application assumed a 97% control efficiency for all connectors in services covered by the proposed 28VHP LDAR program."[162] However, the allowed control efficiency for connectors under the 28VHP LDAR program is only 30% of the control efficiency assumed in the draft TCEQ guidance and relied upon in the Application. A higher control efficiency is only allowed if the LDAR program meets certain conditions, including weekly inspections and monitoring at the same leak definition as valves.[163] The Draft Permit does not satisfy these conditions.

First, the Draft Permit does not clearly require weekly physical inspections of connectors, but rather only "routine walk-throughs by operators" (Condition 4.9.2.b and 4.9.7.b), where "routine" is not defined. While Condition 4.9.6.j suggests that weekly physical inspections are intended, the requirement is ambiguous. I suggest that Condition 4.9.6.g be modified to state: "All connectors shall be physically inspected at least weekly."

---

[160] Commenter's Exhibit 21, see p. 2-19.
[161] Commenter's Exhibit 21, see Table 2-9.
[162] Ap., v. 1, Appx. C, Tables C-24.2, C-25.2, C-26.2, and C-27.2.
[163] TCEQ, 10/00, p. 52.

Second, the LDAR program in the Draft Permit only requires organic vapor analyzer ("OVA") monitoring of connectors once per year, while other components that are assigned a 97% control efficiency are monitored quarterly. Thus, assuming the same control efficiency as for valves and pumps likely underestimates connector emissions. Support should be provided for the very high control efficiency for connectors based on only annual monitoring.

Third, the Application concluded VOM BACT for equipment leaks is an emission limit of 2.44 ton/yr, demonstrated by conducting an LDAR program in accordance with the requirements in Exhibit 391-7 to the 391-CAAPP for fugitive emissions in Appendix A.[164] This exhibit contains conditions for connectors that are not present in the Draft Permit including Conditions C (no buried connector unless welded) and E (piping connections shall be welded or flanged, testing of component at operating pressure; weekly visual, audible, and/or olfactory inspections of connectors.).

Thus, the emissions from connectors should be calculated assuming only 30% control, unless the Draft Permit is modified to require weekly inspections and more frequent OVA monitoring. Correcting this error increases total emissions from these connectors from 0.53 ton/yr to 12.5 ton/yr for emissions estimated with the "without ethylene" emission factors and from 1.4 ton/yr to 31.9 ton/yr when estimated with the average SOCMI emission factors.

The comment acknowledges the 28VHP LDAR program, as guided by TCEQ, justifies a control efficiency for valves and connectors of 97%, as applied in the TEC application. The LDAR requirements that achieve this reduction include weekly physical inspections for connectors and quarterly monitoring for valves and connectors at a leak definition of 500 ppm.

The comment asserts that the Draft Permit does not explicitly require quarterly monitoring of connectors, and thus the 97% control efficiency cannot be applied to connectors. The comment alleges three permit deficiencies that they suggest be addressed by changes to the Draft Permit:

1. **Condition 4.9.6(j) is ambiguous in stating that weekly physical inspections are "intended," and should be modified to state: "All connectors shall be physically inspected at least weekly."**
2. **The Draft Permit only requires OVA monitoring of connectors once per year. This should be revised to require connector monitoring on a quarterly basis.**
3. **Exhibit 391-7 to the 391-CAAPP for fugitive emissions in Appendix A contains conditions for connectors that are not present in the permit. The permit should be revised to include referenced Condition C "no buried connectors unless welded" and Condition E "piping connections shall be welded or flanged, testing of component at operating pressure; weekly visual, audible, and/or olfactory inspections of connectors."**

[164] Ap., v. 1, p. 6-52, Sec. 6.6.2.5.

Because of these alleged deficiencies in the Draft Permit, the comment claims that only a 30% control credit should be applied to emissions from connectors, and the BACT limit of 2.44 tpy is based on an underestimation of emissions.

For the first alleged deficiency, the comment claims that Condition 4.9.6(j) is ambiguous in its reference to Condition 4.9.7(b). The comment's confusion is noted, and the issued permit has been clarified to revise this condition to reference 4.9.6(b) instead. The corrected reference will then point to the requirement for "Accessible connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through." Through this update, the permit condition is not ambiguous, and the TEC meets the weekly physical inspection requirement necessary to apply a 97% control credit for connectors.

In response to the comment's second alleged deficiency, the issued permit was revised to increase the stringency of Condition 4.9.6(j) to reflect the additional requirement of TCEQ's 28CNTQ program and not the 28CNTA program that had been inadvertently included in the draft permit. The 28VHP program alone only requires weekly physical inspections of connectors for a 30% control credit. To achieve a higher control credit, facilities must either conduct annual or quarterly instrument monitoring at a leak detection threshold of 500 ppm. The ELC emission calculations in Sections C-24 to C-27 of Appendix C to Volume 1 appropriately reference the 97% control credit for quarterly instrument monitoring of connectors at a leak detection threshold of 500 ppm, but the draft permit inadvertently included a reference to annual monitoring.

In the third claimed deficiency, the comment requests that LDAR requirements from Exhibit 391-7 to the 391-CAAPP presented in Appendix A of the application be included in the Draft Permit. With reference to Condition C in Exhibit 391-7 of the Application, the IEPA must have expected no underground process pipelines to be present at the TEC or that any underground process pipelines would not have any buried valves and would be welded as part of general good engineering practices. This change is not necessary because the component counts in Section C-24 to C-27 of Appendix C contained no buried valves or connectors and none are expected to be present at the facility. Condition E of Exhibit 391-7 addresses "new and reworked piping connections" at existing and modified sites to replace screwed connections. Since the TEC will be a new facility, screwed connections are prohibited and Condition E is not applicable.

45. Control efficiencies are inappropriately applied for components in heavy liquid service. The control efficiencies were based on a "non-directed maintenance LDAR program labeled as 28VHP for valves, PRVs, and connectors in gas service and opened ended lines," based on the draft TCEQ *Air Permitting Technical Guidance for Chemical Sources: Equipment Leak Fugitives.*[165] The draft TCEQ guidance sets out special conditions that must be satisfied to qualify for the 28VHP designation and associated emission reductions. These are not satisfied in either the emission calculations or the Draft Permit conditions.

[165] See, e.g., Ap., v. 1, Appx. C, Tables C-24.2, C-25.2, C-26.2, and C-27.2, notes 4.

The emission calculations applied the 28VHP control efficiencies to components in heavy liquid service, even though they are explicitly exempt from LDAR. The 28 VHP classification shall not apply where VOC has a vapor pressure of less than 0.044 psia at 68°F[166] as the saturation concentration is less than the leak definition, meaning that LDAR would not detect and repair leaks.[167] Heavy liquids are defined as having a vapor pressure of 0.044 psia or less at 68°F.[168] Thus, emissions from components designated as in heavy liquid service should not be reduced to account for an LDAR program. Further, Condition 4.9.2(a)(ii) of the Draft Permit would explicitly eliminates these components from the LDAR program.

However, the emission calculations apply the 28VHP control efficiency of 93% to 97% to valves, pumps, and compressors in heavy liquid (triethylene glycol), which the Application properly classifies as "heavy liquid service" and specifically notes it has a vapor pressure less than 0.0147 psia.[169] Thus, the emissions from these components are underestimated. Correcting this error increases total emissions from these components from 0.03 ton/yr to 0.54 ton/yr for emissions estimated with the "without ethylene" emission factors and from 0.08 ton/yr to 2.3 ton/yr for emissions estimated with the average SOCMI factor.

The comment again references TCEQ's guidance for 28VHP LDAR requirements as a basis for applying appropriate control credits. As acknowledged by the comment, the 28VHP program and the requirements of the permit [Condition 4.9.2(a)(ii)] appropriately exempt process streams from the LDAR requirements where the VOM partial pressure of the stream is less than 0.044 pounds per square inch, absolute (psia) at 68 °F. Components with a process stream meeting these characteristics have a very low VOM emissions potential, and in some cases, the saturated concentration of these streams is less than the 500 ppmv leak definition, thus making the stringent LDAR requirements of little benefit.

CCG specifically requested inclusion in the LDAR program the components in triethylene glycol (TEG) service, including heavy liquid service, within the SNG drying process of the Gasification/Syngas Conditioning/Methanation process areas. Because Condition 4.9.2(a)(i)(A) specifically delineates that components in TEG service shall be included in the LDAR requirements, the TEG connectors in heavy liquid service are required to follow the stringent LDAR requirements of the Draft Permit, patterned after TCEQ's 28VHP program. Therefore, the comment is incorrect in stating that the Draft Permit explicitly eliminates these components from the LDAR program.

The TCEQ equipment leak guidance specifically notes that control credits may be taken for low vapor pressure compounds such as components in TEG service. TCEQ provides the following qualifying statement for when low vapor pressure compounds can be subject to instrument monitoring: "an applicant may propose to monitor these components and take the appropriate reduction credits as noted in Attachment III; however, the applicant must demonstrate that leaking components can be detected by

[166] TCEQ 10/00, p. 33, Condition A. *See* also Table 1, which reports that 28 VHP applies only to components with a vapor pressure >0.044 psia at 68°F.
[167] TCEQ 10/00, p. 14.
[168] TCEQ 10/00, p. 7.
[169] Ap., Appx. C, p. C-105, Table C-24.2, note 4.

implementing an instrument assisted fugitive monitoring program."[170] The TEG streams included in the LDAR requirements of the Draft Permit have a vapor pressure of 0.0147 psia. At this vapor pressure, the theoretical-saturation concentration is 1,000 ppm (0.0147/14.7 x 1,000,000 = 1,000 ppm). The Issued Permit will include a leak definition of 500 ppmv for heavy liquid connectors and pumps subject to the LDAR program. Since this leak detection threshold is less than the saturation concentration for TEG, instrument monitoring is feasible and it is appropriate to assign control credits to the emissions from these components. As discussed previously, the TCEQ equipment leak guidance document allows control credits for heavy liquid connectors and pumps of 97% and 93%, respectively for quarterly instrument monitoring of these components at a leak detection threshold of 500 ppm.

The issued permit explicitly requires inclusion of components in TEG service under the LDAR requirements. TCEQ guidance defines appropriate control credits for components in heavy liquid service where the leak definition is less than the saturation concentration, as is the case for TEG. Therefore, the emissions calculations in the Application are appropriate, and the statements in the comment are incorrect.

46. Emissions were underestimated because of the approach used to speciate SOCMI Emission Factors. The low ethylene SOCMI total emissions were converted into other pollutants by multiplying total emissions by a weighted average concentration of certain chemicals and groups of chemicals found in eight subsets of process streams. The pollutants and pollutant groups are: COS, methanol, hydrogen cyanide ("HCN"), hydrogen chloride ("HCl"), formic acid, CO, H_2S, ammonia ("NH_3"), regulated VOM (never defined, but presumably regulated "volatile organic matter" (ozone-precursor volatile organic matter, including all HAPs), CH_4, CO_2, and certain other unidentified "other volatile or semivolatiles" footnoted to include non-regulated constituents in process fluids which primarily include CH_4, hydrogen ("H_2"), water vapor, and CO_2).[171] There are a number of problems with these conversions.

First, the Application and supporting permit record contain no support for these weighted average concentrations, which were used to estimate emissions of VOM, CO, CH_4, CO_2, and many HAPs emissions from fugitive components. These were reportedly derived from mass balances, but these mass balances were not produced preventing any meaningful review.[172] Thus, these emissions are unsupported in the Permit record, and it is evident that IEPA either did not produce the relevant documents or did not itself review the basis for the fugitive emission calculations, based on the documents produced in response to my FOJA request.

Second, the speciated data include two subsets of compounds that are not defined: (1) other volatile or semivolatiles and (2) regulated VOM. Other volatile and semivolatile compounds are defined as to "include non-regulated constituents in the process fluid which primarily include methane (CH_4), hydrogen (H_2), water vapor, and carbon dioxide (CO_2)."[173] The

---

[170] Commenter's Exhibit 23, see footnotes 2 and 4 to the Table "Control Efficiencies for TCEQ Leak Detection and Repair Programs" on page 53.

[171] Ap., v. 1, Appx. C, pp. C-104 to C-111.

[172] Ap., v. 1, p. 3-17 (**"...** contacting process stream compositions for all compounds present at detectable levels were calculated based on heat and material balance data.")

[173] Ap., v. 1, Appx. C, pp. C-104 to C-ill, footnotes.

CH_4 and CO_2 are broken out in Appendix A of Volume 3 of the Application, which contains the GHG BACT analysis, but one is left to guess what additional chemicals might be present.

Regulated VOCs are not defined at all, leaving one to guess what might be included. The PSD VOC parameter is defined at 40 CFR 51.100(s).[174] This definition is subject to legal interpretation as to which specific compounds are included and excluded. As VOC here was estimated from undisclosed material balances, which were not produced, it is not possible to determine if the VOM category used to estimate VOC emissions properly includes all ozone precursor compounds. (The Application refers to this pollutant as VOM, without ever defining it. The regulated PSD pollutant is volatile organic compounds or VOCs, creating ambiguity and uncertainty as to what is included.) For example, it is unclear whether methanol, a HAP, is also included as a VOC, or excluded under the same reasoning used to exclude COS and H_2S from the PSD pollutants total sulfide compounds.

Third, the SOCMI emission factors used as the starting point were not developed specifically for use with inorganic compounds (COS, HCN, HCl, CO, H_2S, NH_3, H_2, CO_2, H_2O), which have very different physical and chemical properties than the total organic compounds measured in the SOCMI studies. These inorganic chemicals make up a significant amount of the emissions from many of the process streams at the TEC. (*See, e.g.*, gasification/syngas condition and methanation process area (18% CO, 11% CO_2); AGR process area (16% CO, 1-6% H_2S, 17-70% CO_2); SRU process area (6-8% CO, 2% NH_3, 20% H_2S, 5% NH_3, 46-47% CO_2), and miscellaneous minor sources (81% CO_2).[175] The instruments used to measure VOCs in the studies used to develop the SOCMI VOC emission factors did not measure these inorganic species in the process gases.[176]

The USEPA, for example, clearly notes that "the emission factors and correlations presented in section 2.3 [and used in the Application based on a TCEQ adaptation] are not intended to be applied for the used [sic] of estimating emissions of inorganic compounds. However, in some cases, there may be need to estimate equipment leak emissions of inorganic compounds. . . The best way to estimate equipment leak emissions of inorganic compounds would be to develop unit-specific correlations as described in section 2.3.4. To do this, it would be necessary to obtain a portable monitoring instrument that could detect the inorganic compounds."[177] CCG made no documented attempt to determine equipment leak emission factors representative of IGCC process streams, or for the specific inorganic compounds present in them.

The comment makes three assertions that the method used in the application to calculate emissions from equipment leak components is incorrect: 1) The application did not contain support for the weighted average concentrations of speciated components from the process streams, other than they were derived from heat and mass balances; 2) The speciated components in the application did not define "other volatile or semivolatile" compounds, nor "regulated VOM" compounds; and 3)

[174] 40 CFR 52.21(b)(30).
[175] Ap., v. 1, Appx. C, pp. C-104 to C-111 and v. 3, Appx. A, pp. A-34 to A-38.
[176] USEPA 1995.
[177] USEPA 1995, Sec. 2.4.7, pp. 2-53 to 2-54.

SOCMI emission factors were not developed for use with inorganic compounds, which make up a portion of the TEC process streams.

First, the comment claims that there is no support for the weighted average used to estimate emissions from ELC. The speciated emissions are calculated using the total controlled emission rate and a weighted percent of vent stream composition for each pollutant, which were both provided in the Application.[178] The stream composition was based on the preliminary engineering design of the facility, and is not necessary to calculate the emission factors. There was sufficient information provided to the IEPA in the Application to review, ensure environmental protection, and prepare an enforceable permit.

Second, the comment claims that the speciated stream composition information included in Sections C-24 to C-27 of Appendix C to Volume 1 fails to define the terms "other volatile or semivolatiles" and "regulated VOM." VOM is defined in Illinois' rules, Title 35 of the Illinois Administrative Code, Section 211.7150. It is clear in the application that all references to VOM would include all speciated volatile organic matter that falls under this definition. This definition of VOM is essentially identical to the federal definition of VOC under 40 CFR 51.100(s) so that the IEPA routinely uses state terminology, VOM rather than VOC, in the permits that it issues. For the purposes of the VOM stream compositions in Sections C-24 to C-27 of Appendix C, these concentrations are simply the sum of the individual compounds flagged as VOM in the equipment leak emissions summary tables. Since these tables include all regulated pollutants (including speciated HAPs) that are expected to be present in measurable quantities within the TEC's process streams, there should be no confusion about which individual VOM compounds are expected to be present in the various ELC process areas considered in the Application. [179] For example, Table C-24.1 of Appendix C to Volume 1 includes "Y" in the VOM column for COS, methanol, hydrogen cyanide (HCN), and formic acid, so the regulated VOM stream composition is the sum of the compositions for each of these individual VOM compounds (i.e., 0.044% for COS + 0.0085% for methanol + 0.00021% for HCN + 0.0045% for formic acid = 0.06 % for VOM).[180]

Third, the comment claims that since SOCMI factors were not established specifically for use with inorganic compounds they are not applicable to streams with significant concentrations of inorganic compounds at the TEC. The comment cites USEPA's *Protocol for Equipment Leak Emissions Estimates* which suggests the best way to estimate emissions of inorganic compounds is to develop unit-specific correlations. It is clear this suggestion is only relevant for existing facilities, and is inappropriate for the TEC permit, as CCG cannot develop unit-specific correlations for a facility that does not yet exist. Advanced coal gasification for the production of SNG is a relatively new

---

[178] App. Table C-24.2 Note 8

[179] Although not required, the application also addressed volatile components present in the process streams that are not include in the VOM definition (see the VOM definition for excluded compounds, which includes methane, hydrogen, water vapor, carbon dioxide, etc.), in the category referred to as nonregulated "other volatile or semivolatiles." It was not necessary to identify every single speciated component comprising nonregulated substances. "Other volatiles" were simply used to represent unregulated compounds that the TEC might emit.

[180] HCN is commonly considered an inorganic compound and not part of VOM. However, CCG conservatively assumed that any compound containing carbon other than CO, CO_2, and CH_4 would be VOM when quantifying equipment leak emission.

technology and there have been no factors published that are specific to such plants, as documented extensively in the response to previous comments. Instead, CCG determined appropriate emissions factors to use in place of unit-specific data. Referencing the TCEQ guidance relied upon in the comments, TCEQ suggests that:

> **For odorous or toxic inorganic compounds such as chlorine (Cl_2), ammonia (NH_3), hydrogen sulfide (H_2S), hydrogen fluoride (HF), and hydrogen cyanide (HCN), fugitive emissions are calculated in the same manner as any VOC fugitive emissions according to the type of facility. Although the VOC emission factors were not developed specifically for use with inorganic compounds, they are presently the best tool available for estimating fugitive emissions of inorganic compounds.[181]**

Due to the lack of directly applicable factors, CCG utilized the "best tool available" and applied the SOCMI without ethylene factors to all process streams at the TEC – including those with a concentration of inorganic compounds. These factors are appropriate and conservative for application to the TEC, as documented in previous responses.

The basis of the speciated emissions, the categorization of volatile compounds, as well as the application of SOCMI without ethylene emission factors to streams with a concentration of inorganic compounds was performed accurately and appropriately in the Application. The comment's claim that the emissions calculations have "problems" is unfounded and neither demonstrates a calculation inaccuracy nor an insufficiency in the calculation basis.

V. BEST AVAILABLE CONTROL TECHNOLOGY

GENERAL

47. Conditions 4.1.2-1(d)(ii)(B), 4.1.6(b) and 4.3.6(b) and (c) in the Draft Permit would provide that certain limits shall not become effective until one year after the shakedown of the gasification block is complete." It is unclear from the Project Summary why the plant is allowed an additional year beyond the initial shakedown period to comply with the BACT emissions limits.

In response to this comment, the clause in question has not been included in the subject condition in the issued permit. The IEPA has further considered these conditions that address emissions from the gasifiers and associated flare and determined that annual emission limits for these units, as would have been addressed by the clause in question, should also be applicable during shakedown of the plant. (This change was also made elsewhere in the permit where this clause was present in the Draft Permit.)

[181] **Commenter's Exhibit 23, see p. 7.**

By way of further explanation, these conditions in the Draft Permit were intended to accommodate unforeseen developments during the shakedown of the gasification block. These developments could reasonably lead to additional shutdowns and subsequent startups of the gasifiers, beyond those expected during routine operation of the gasification block and accounted for in the annual emission limits that have been set for the flare. Air quality during shakedown would still have been protected by the short-term limits for these units, which would apply during shakedown. In the issued permit, both short-term and annual limits would now apply during shakedown.

48. BACT must apply at all times, including the initial shakedown period, so the permit should contain a BACT limit applicable during the shakedown period. If IEPA has determined that compliance with the BACT emissions limits is infeasible during the initial shakedown period, it may establish secondary BACT limits or work practices for those specific periods. If this is the case, such secondary limits or work practices must be justified as BACT in the permitting record and IEPA must ensure that all PSD requirements, including compliance with National Ambient Air Quality Standards (NAAQS) and PSD increments, are met during these times.[182] The permit should ensure that the BACT emission limits or work practices are effective at all times, and not exempt any periods of shakedown or other operational periods (e.g., startup and shutdown).

The permit includes BACT limits and requirements that are applicable at all times. As discussed above, as related to BACT, the Draft Permit would only have phased in certain BACT limits with the conclusion of the shakedown period. The applicability or timing of other BACT limits and requirements would not have been affected. In response to the previous comment, all BACT limits and requirements would now apply at all times. Accordingly, it is not necessary to consider the establishment of secondary BACT limits for shakedown, as discussed by this comment.

49. The Clean Air Act requires that a permit issued to a major new source in an attainment area include emission limits that reflect the installation of BACT. The limits proposed in the Draft Permit do not represent BACT because they fail to reflect the maximum emission reductions that are achievable at the TEC. BACT Requires a Thorough and Well-Documented Analysis Aimed At Identifying the Maximum Emission Reductions Achievable. BACT requires a case-by-case analysis in order to determine the lowest emission rate for the pollutant in question for the source in question, reflecting the maximum degree of emissions reduction that is achievable considering collateral factors such as cost, energy, and other environmental impacts. [183, 184] By using the terms "maximum" and "achievable,' the Clean Air Act sets forth a "strong, normative" requirement that "constrain[s]" agency discretion in determining BACT. *Alaska DEC,* 540 U.S. at 485-86. Pursuant to those requirements, "the most stringent technology is BACT" unless the applicant or Agency can show that such technology is not feasible or should be rejected due

[182] See In re Prairie State Generating Company, 13 E.A.D. 1, 85-91 (EAB 2006); In re Indeck-Niles Energy Center, 13 E.A.D. 126, 170-181 (EAB 2004); In re RockGen Energy Center, 8 E.A.D. 536, 551-555 (EAB 1999).

[183] Under the Clean Air Act, BACT is defined 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." 42 U.S.C. § 7479(3).

[184] NSR Manual, pp. B.1-B.2, B.5 and B.23.

to specific collateral impact concerns. *Alaska Dep't of Envtl. Conserv. v. EPA*, 298 F.3d 814, 822 (9th Cir. 2002). The collateral impacts exception is a limited one, designed only to act as a "safety valve" in the event that "unusual circumstances specific to the facility make it appropriate to use less than the most effective technology." *In re Kawaihae Cogeneration Project*, PSD Appeal Nos. 96-6, 96-10, 96-11, 96-14, 96-16, 7 E.A.D. 107, 117 (LAB. Apr. 28, 1997); *In re World Color Press, Inc.*, 3 E.A.D. 474, 478 (Adm'r 1990) (collateral impacts clause focuses on the specific *local* impacts); *In re Columbia Guf Transmission Co.*, PSD Appeal No. 88-11, 2 E.A.D. 824, 827 (Adm'r 1989); NSR Manual at B.29. If the Agency proposes permit limits that are less stringent than those for recently permitted similar facilities, the burden is on the applicant and agency to explain and justify why those more stringent limits were rejected. *In re Indeck-Elwood, LLC*, PSD Appeal 03-04, 13 E.A.D.--, slip op. at 77, 79-81 (EAB. Sept. 27, 2006); *In re Knauf Fiber Glass, GMBH*, PSD Permit No. 97-PO-06, 8 E.A.D. 121, 131-32 (EAB. Feb. 4, 1999). The need to aim for the lowest limits achievable as part of a BACT analysis was recently emphasized by the EAB, which stated in reversing a permit issuance:

> If reviewing authorities let slip their rigorous look at 'all' appropriate technologies, if the target ever eases from the 'maximum degree of reduction' available to something less or more convenient, the result may be somewhat protective, may be superior to some pollution control elsewhere, but it will not be BACT.
> *In re: Northern Michigan University Ripley Heating Plant*, PSD Appeal No. 08-02, slip op. at 16 (EAB 2009) (hereinafter *"In re NMU"*);[185]

BACT's focus on the maximum emission reduction achievable makes the standard both technology-driven and technology-forcing.[186] A proper BACT limit must account for both general improvements within the pollution control technology industry and the specific applications of advanced technology to individual sources, ensuring that limits are increasingly more stringent. BACT may not be based solely on prior permits, or even emission rates that other plants have achieved, but must be calculated based on what available control options and technologies can achieve for the project at issue and set standards accordingly.[187] For instance, technology transfer from other sources with similar exhaust gas conditions must be considered explicitly in making BACT determinations.[188]

The BACT review "is one of the most critical elements of the PSD permitting process" because it determines the amount of pollution that a source will be allowed to emit over its lifetime. *In re Mississippi Lime*, 15 E.A.D. --, slip op. at 17; *In re Knauf* 8 E.A.D. at 123-24.

---

[185] *See* also *Utah Chapter of Sierra Club*, 226 P.3d at 734-35 (remanding permit where there "was evidence that a lower overall emission limitation was achievable").

[186] NSR Manual, p. B.12 ("[T]o satisfy the legislative requirements of BACT, EPA believes that the applicant must focus on technologies with a demonstrated potential to achieve the highest levels of control"); pp. B.5 ("[T]he control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams); and B. 16 ("[T]echnology transfer must be considered in identifying control options. The fact that a control option has never been applied to process emission units similar or identical to that proposed does not mean it can be ignored in the BACT analysis if the potential for its application exists.")

[187] An agency must choose the lowest limit "achievable." While a state agency may reject a lower limit based on data showing the project does not have "the ability to achieve [the limit] consistently," *In re Newmont*, PSD Appeal No. 05-04, 12 E.A.D. 429, 443 (E.A.B. Dec. 21, 2005), it may only do so based on a detailed record establishing an adequate rationale, *see id* Moreover, actual testing data from other facilities is relevant to establishing what level of control is achievable given a certain technology. *Id.* at *30 The word "achievable" does not allow a state agency to only look at past performance at other facilities, but "mandates a forward-looking analysis of what the facility [under review] can achieve in the future." *Id.* at *32. Thus, the agency cannot reject the use of a certain technology based on the lack of testing data for that technology, where the record otherwise establishes that the technology is appropriate as an engineering matter. NSR Manual, at B.5.

[188] NSR Manual, p. B.5.

As such, the BACT analysis must be "well documented" and a decision to reject a particular control option or a lower emission limit "must be adequately explained and justified." *In re Mississippi Lime,* slip op. at 17; *In re Knauf* at 131. While the applicant has the duty to supply a BACT analysis and supporting information in its application, "the ultimate BACT decision is made by the permit-issuing authority." *In re: Genesee Power Station Ltd Partnership, 4* E.A.D. 832, 835 (EAB 1993). Therefore, IEPA has an independent responsibility to review and verify CCG's BACT analyses and the information upon which those analyses are based to ensure that the limits in any permit reflect the maximum degree of reduction achievable for each regulated pollutant. *See* 42 U.S.C. § 7479(3) ("permitting authority" makes BACT determination).

Information to be considered in determining the performance level representing achievable limits includes manufacturer's data, engineering estimates, and the experience of other sources.[189] CCG and the IEPA must survey not only the USEPA RACT/BACT/LAER clearinghouse database ("RBLC"), but also many other sources, both domestic and foreign, including other agencies' determinations and (draft) permits, permit applications for other proposed plants, technology vendors, performance test reports, consultants, technical journal articles, etc.

This comment provides a legal overview concerning the scope of a BACT analysis. The IEPA does not disagree with most of the general statements relating to BACT, however, there are certain statements that do not reflect applicable law and guidance. First, the consideration of collateral impacts is not an exception to BACT; it is an inherent part of the BACT analysis. The scope of review of energy, environmental and economic considerations under Step 4 may be narrow by virtue of its focus on "unusual circumstances," but that does not suggest that the earlier stages of the analysis (i.e., Steps 1 and 2) establish a rule or presumptive command concerning the selection of an appropriate control. Consistent with applicable law and USEPA guidance, the IEPA's scrutiny of collateral impacts provided a "hard look" at all of the appropriate control technologies.

Secondly, while BACT may be forward-looking in its approach, this does not mean that the permit applicant or permitting authority is obligated to force or impose a particular technology [or a level of control] that cannot be achievable to a source at the time of permitting. The use of the term "achievable" in the Clean Air Act's definition of BACT illustrates that the permitting analysis should be grounded in present reality, not the promise of some unproven or future technology. As the EAB has observed, "the word 'achievable' used in the statute and regulations, although forward-looking, also constrains the permit issuer's discretion by prohibiting BACT limits that would require pollution reductions greater than what can be achieved with available methods."

***See, In re Newmont Nev. Energy Investment, LLC,* 12 EAD 429, 441 (EAB 2005)(in evaluating the level of emissions control, the BACT analysis "must be**

[189] NSR Manual, p. B.24.

solidly grounded on what is presently known about the selected technology's effectiveness at controlling pollutant emissions").

Moreover, the BACT evaluation is intended to arrive at a control option that is *technically feasible*. *See*, NSR Manual, B.7, 17 (Draft - October 1990). The requirement for technical feasibility means that a control option must be either demonstrated in practice or is both available and applicable to the source. *Id.* If the control option has been successfully implemented to a source type under review, it is considered a demonstrated technology. *Id.* If the control option is not demonstrated in practice, it is considered to be technically feasible if it can be obtained commercially (i.e., available) and can be installed and operated on the source in question (i.e., applicable). *Id.*

A technology that is not beyond the conceptual or early stages of development at the time of permitting is not an "available" technology. *Id. at B.18; see also, In re Cardinal FG Co.*, 12 EAD 153, 163 (EAB 2005); *U.S. v. Minnkota Power Coop., Inc.*, Order Denying Plaintiff's Motion to Stay and Motion for Dispute Resolution (Case 1:06-cv-034), Document 35 at 5. A permit applicant is not expected to "experience extended time delays or resource penalties to allow research to be conducted on a new technique." NSR Manual, page B.18. A permit applicant also need not "experience extended trials to learn how to apply a technology on a totally new and dissimilar source type." *Id.*

It is clear from this guidance that promising technologies that are not yet developed or proven do not meet the requirements of technical feasibility. BACT does not compel a permit applicant or permitting authority to speculate as to the effectiveness [or appropriate level of control] for an undemonstrated or unavailable control option. Similarly, BACT does not require an applicant to accept the risks that a promising but as-yet unproven technology may actually not prove workable at the proposed source. In this regard, BACT cannot be interpreted to force an applicant to select a control option that is beyond the limits of technical feasibility. *See generally, PSD and Title V Permitting Guidance for Greenhouse Gases (March 2011)* at page 17.

It is noted that the comments appear to call into question the basis for the IEPA's refusal to consider CCS as a BACT-required control option. To the extent that CCS can be expected to become demonstrated or available in the future, it may be applied by TEC at some future date, especially if the source maintains a desired goal of achieving compliance with a state law currently providing incentives for the development of coal gasification in Illinois. For purposes of BACT, however, the IEPA is constrained by the existing construct of the PSD program and cannot ignore the fact that CCS is simply not technically feasible for this proposed source at this time.

50. BACT is typically evaluated through a Top-Down 5-Step, process. The USEPA established the top-down process described in the NSR Manual in order to ensure that a BACT determination is "reasonably moored" to the Clean Air Act's statutory requirement that

BACT represent the maximum achievable reduction.[190] While an agency is not required to utilize the top-down process as laid out in the NSR Manual, where it purports to do so, the process must be applied in a "reasoned and justified manner." *Alaska Dep't of Envtl. Conserv.*, 298 F.3d at 822. As the USEPA's. Environmental Appeals Board ("EAB")[191] recently explained:

> The NSR Manual's "top-down" method is simply stated: assemble all available control technologies, rank them in order of control effectiveness, and select the best. So fixed is the focus on identifying the "top," or most stringent alternative, that the analysis presumptively ends there and the top option selected "unless" technical considerations lead to the conclusion that the top option is not "achievable" in that specific case, or energy, environmental, or economic impacts justify a conclusion that use of the top option is inappropriate.
> *In re NMU*, slip op. at 13.

More specifically, the top-down BACT process typically involves the following five steps: 1. Identify All Available Control Options; 2. Eliminate Technically Infeasible Options; 3. Rank Remaining Control Technologies by Control Effectiveness; 4. Evaluate the Most Effective Controls and Document the Results; and 5. Select BACT.[192]

These comments further elaborate on some of relevant details and scope of the BACT analysis. The IEPA's evaluation of BACT reflected a case-by-case determination accounting for site-specific and source-specific considerations. The permit applicant and the IEPA adhered to the Top-Down BACT Process recommended by USEPA for

---

[190] *Alaska Dept. of Envt'l Conservation v. EPA*, 540 U.S. 461, 485 (2004).

[191] The EAB is the USEPA's supreme adjudicative body. *See* Changes to Regulations to Reflect the Role of the New Environmental Appeals Board in Agency Adjudications, 57 Fed. Reg. 5320 (Feb. 13, 1992). EAB decisions represent the position of the EPA Administrator with respect to the matters brought before it. *See Tenn. Valley Auth. v. EPA*, 278 F.3d 1184, 1198—99 (11th Cir. 2002) (finding EAB decision to be "final agency action").

[192] By way of further explanation, the five steps in the Top-down BACT process are as follows:

a. Identify All Available Control Options

The first step in the BACT process is to identify "all potentially available control options." *In re Mississippi Lime*, slip op. at 11. The goal at this step is to cast as wide a net as possible so that a "comprehensive list of control options" is compiled. *In re Knauf*, 8 E.A.D. at 130. As the EAB has emphasized, "available is used in its broadest sense under the first step and refers to control options with a 'practical *potential* for application to the emission unit under evaluation." *Id.* (emphasis in original). A control option is considered "available" if "there are sufficient data indicating (but not necessarily proving)" the technology "will lead to a demonstrable reduction in emissions of regulated pollutants or will otherwise represent BACT." *In re Spokane Regional Waste-to-Energy Applicant*, 2 E.A.D. 809, slip op. at 22 (Adm'r June 9, 1989). The definition of BACT requires that the options considered include "application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant." 42 U.S.C. § 7479(3).

b. Eliminate Technically Infeasible Options

Step two of the BACT process involves evaluating the technical feasibility of the available options and eliminating those that are not feasible. NSR Manual at B.7; *Indeck-Elwood*, slip op. at 11. Feasibility focuses on whether a control technology can reasonably be installed and operated on a source given past use of the technology. *Id.; In re Knauf* 8 E.A.D. at 130. Feasibility is presumed if a technology has been used on the same or similar type of source in the past. *Id.* This step in the analysis has a purely technical focus and does not involve the consideration of economic or financial factors (including project financing).

c. Rank Remaining Control Technologies by Control Effectiveness

The next step in BACT process is to rank the available and feasible control technologies for each pollutant in order of effectiveness. *In re Mississippi Lime*, slip op. at 12. That is, for each pollutant, the most effective control option is ranked first, and relatively less effective options follow with the least effective option ranked last.

d. Evaluate the Most Effective Controls and Document the Results

The fourth step in the BACT process is to evaluate the collateral economic, environmental and energy impacts of the various control technologies. NSR Manual, B.26; *Indeck-Elwood*, slip op. at 12. This step typically focuses on evaluating both the average and incremental cost-effectiveness of a pollution control option in terms of the dollars per ton of pollution emission reduced. *In re Mississippi Lime*, slip op. at 12. The point of this review is to either confirm the most stringent control technology as BACT, considering economic, environmental, or energy concerns, or to specifically justify the selection of a less stringent technology based on consideration of these factors. *Id.*

e. Select BACT

The final step in the BACT process is to select the most effective control option remaining after Step 4. This option must represent the "maximum degree of reduction... that is achievable" after "taking into account energy, environmental, and economic impacts and other costs."

the proposed project and, in their respective roles, both assembled and reviewed all available control technologies, ranked them according to their proper order of effectiveness and appropriately selected the best control option as BACT for those regulated pollutants to be emitted by the TEC project.

ANALYSIS IMPROPERLY FAILED TO CONSIDER OR REQUIRE CLEANER FUELS

51. CCG's BACT analysis did not consider cleaner fuels as an alternate feedstock for gasification and argued that they were technically infeasible for short-term use during planned startups and shutdown. Instead, the application argues that the project is not economic without funding under the Illinois Clean Coal Portfolio Standard Law (the "Clean Coal Act" or "CCA"), which requires the use of coal with at least 1.7 lb S/MMBtu.[193] This state law impermissibly takes cleaner coal off the table as BACT and thus violates federal PSD rules.[194] The IEPA adopted CCG's flawed reliance on the CCA and also argued that any other fuel would require redesign of gas treatment and material handling systems and would not result in significantly lower emissions.[195] The application did not evaluate cleaner fuels as an option for reducing emissions, but rather argued generally and without support that they are not feasible or would improperly require a redesign of the proposed source. The Project Summary approached cleaner fuels in a similar manner.

The Clean Air Act requires an evaluation of cleaner fuels as an option for reducing emissions. IEPA and CCG's failure to consider cleaner fuels as an option for reducing emissions from the TEC runs contrary to the clearly established requirement that a BACT determination include consideration of "clean fuels." 42 U.S.C. § 7479(3). As explained above, the fundamental first step in a BACT analysis is to identify all available options for reducing emissions from a proposed source. Such options must include not only add-on controls, but also other "production process and available methods, systems, and techniques." 42 U.S.C. § 7479(3).[196]

To not evaluate cleaner fuels would "pointedly frustrate congressional will," *id.*, by reading the phrase "clean fuels" out of the statutory definition of BACT. *Sierra Club v. EPA*, 499 F.3d 653, 656 (7th Cir. 2007). As such, the evaluation of the use of lower sulfur coal and other cleaner fuels is a required part of a BACT analysis. *In re NMU*, slip op. at 17-18; *In re E. Ky. Power Coop., Hugh L. Spurlock Generating Station*, Petition No. IV-2006-4, Order at 30-32 (EPA Adm'r Aug. 30, 2007); *In re Inter-Power*, 5 E.A.D. at 134; *In re Haw. Commercial & Sugar Co.*, PSD Appeal No. 92-1, 4 E.A.D. 95, 99 n.7 (E.A.B. 1992); *In re Old Dominion Elec. Coop.*, PSD Appeal No. 91-39, 3 E.A.D. 779, 794 n.39 (Adm'r 1992).

[193] Ap., v. 1, p. 5-9. *See* also Project Summary, p. 24 ("The coal feedstock selected by an entity proposing to gasify coal may be critical to the economic feasibility and viability of the proposed project... This is the case for the proposed plant, for which Illinois Basin coal... is the design supply.").
[194] Ap., v. 1, pp. 5-6 to 5-9.
[195] Project Summary, pp. 24-26.
[196] In 1990, Congress added "clean fuels" to the definition of BACT, 42 U.S.C. § 7479(3), in order to codify long time USEPA practice requiring the evaluation of the use of cleaner fuels as an available method for reducing emissions. *In re Inter-Power of New York; Inc.*, PSD Appeal Nos. 92-8 and 92-9, 5 E.A.D. 130, 134 (E.A.B. Mar. 16, 1994). As a result of this amendment, the EAB has found that the Clean Air Act "promotes clean fuels with particular vigor." *In re NMU*, slip op. at 27.

Where, as here, a cleaner fuel is a technically feasible option for reducing emissions, IEPA and CCG may only justify rejecting that cleaner fuel as the basis for BACT emission limits on a proper Step 4 collateral impacts analysis. *See* 42 U.S.C. § 7479(3); *Knauf* 8 E.A.D. at 131 (agency must fully explain its reasons for rejecting the top control technology based on, among other things, collateral impacts); *In re Columbia Gulf Transmission Co.*, 2 E.A.D. 824, 830 (EAB 1989); *In re CertainTeed Corp.*, 1 E.A.D. 743, 747-49 n.11-12 (EAB 1982) ("general unquantified concerns about collateral impacts, without more, do not justify the rejection of a more stringent technology"); NSR Manual at B.47-48. A permitting agency may only sparingly make a finding that a cleaner fuel is not feasible, and only based on circumstances unique to the project. *In re Kawaihae Cogeneration Project*, 7 E.A. D. 107, 116-17 (EAB 1997); *see also In re World Color Press*, 3 E.A.D. at 478. Therefore, general assertions about the economic feasibility of using a cleaner fuel are not, by themselves, sufficient to justify rejecting cleaner fuels as a control option for reducing pollutants from the TEC. *See Alaska DEC*, 540 U.S. at 476 (rejecting a BACT analysis where the agency eliminated a control option on claims of economic infeasibility without adequate justification). Rather, clean fuels may be rejected as a pollution control option only if the cost-per-unit of pollutant prevented is disproportionate to the cost per ton incurred by other sources controlling the pollutant in recent BACT determinations. *See In re Masonite Corporation*, PSD Appeal No. 94-1, 5 E.A.D. 551 (EAB 1994).

For a gasification plant, like the TEC, the clean fuels standard may require, among other things, the use of less-polluting feedstocks such as biomass or lower-sulfur coal. Because the BACT analysis fails to properly consider such clean feedstocks, the Draft Permit would be deficient.

This comment generally contends that the IEPA's BACT analysis did not properly consider the "clean fuels" requirement in the definition of BACT. The IEPA acknowledges that the consideration of clean fuels is ordinarily a part of a typical BACT evaluation. However, such consideration is not required where, as here, the use of such purported clean fuels would redefine the source.

The comment largely overlooks the fact that the TEC project is being designed as a *coal* gasification plant, and the use of higher sulfur bituminous coal, which is a raw material or Feedstock not exclusively found in Illinois, is a fundamental component of the proposed project. The gasification block in the TEC would operate as a fuel conversion plant, converting a feedstock into SNG, but only the latter will be utilized as a fuel. The evaluation of clean fuels that typically accompanies a BACT analysis is not appropriate to compel the use of a different feedstock for the gasification process (coal is the feedstock for the plant and not a fuel), as such use would fundamentally redefine the nature of the source.

In addition, the selection of coal from the Illinois Basin as a feedstock for the TEC is an inherent aspect of the proposed project for reasons that relate to its fundamental business purpose and intended design. As discussed further in the discussion below, the use of coal from the Illinois Basin as feedstock for the project is designed to meet the requirements of state legislation that seeks to promote the development of clean energy using Illinois coal. CCG has

developed its business plan to take advantage of certain incentives in the law and intends to develop the proposed project consistent with the law's requirements. Consideration of low-sulfur coal for the project as a feedstock would effectively deny eligibility to CCG of the benefits of the state law and frustrate the broader policy objectives of the legislation. As discussed later, the use of low-sulfur coal has also been rejected on technical and economic grounds.

The comment also argues that the IEPA can only reject a cleaner fuel for reasons that relate to the collateral impacts analysis under Step 4 of the Top-Down BACT Process. The IEPA disagrees with this notion. Although CCG has provided information on the cost-effectiveness of certain alternative feedstocks, as would be required at Step 4, and that information support elimination of those alternative feedstocks based on their cost impacts, the IEPA was not precluded by applicable law or USEPA guidance in eliminating clean fuel alternatives as a control option at earlier steps of the Top-Down BACT Process. In this instance, the IEPA rejected the use of certain alternative fuels for the project because such use would redefine the proposed source. The IEPA also ruled out the use of certain alternative fuels for reasons relating to technical feasibility, suitability and/or emissions control effectiveness.

52. For this project, the use of cleaner fuels would not redefine the source. In the Project Summary, pages 24 - 26, the IEPA attempts to avoid the clean fuels requirement by contending that use of a cleaner fuel would "redefine the source" proposed by CCG in two ways. First, IEPA notes that CCG is proposing to develop a plant that would qualify for coverage under the CCA, a state law that would effectively provide an economic subsidy for the TEC. Because the CCA requires, among other things, that a qualifying plant use bituminous coal with a sulfur content of at least 1.7 lbs/mmBtu, IEPA asserts that requiring the TEC to use a cleaner fuel "would fundamentally alter the business purpose and stated goals of the project" and, therefore, redefine the source. Second, IEPA asserts that the use of a lower sulfur coal feedstock would require changes to the feedstock, gasifier, and syngas conditioning trains that would purportedly redefine the source.

The IEPA's reliance on the redefining the source policy is misplaced. The only limit on the Clean Air Act's clean fuel mandate recognized by the courts is where a fuel change would fundamentally change the physical scope of the project. In other words, the "redefining the source" policy only prevents the permitting agency from requiring the applicant to build a different type of facility- such as substituting a power plant for a municipal waste combustor. *In re Hibbing Taconite Company*, 2 E.A.D. 838, 843 and n.12 (Adm'r 1989). The Administrator in *Hibbing Taconite* explained that a change in fuel type does not redefine the source.

> Traditionally, EPA has not required a PSD applicant to redefine the fundamental scope of its project... [The redefining the source] argument has no merit in this case. EPA regulations define major stationary sources by their product or purpose (*e.g.*, "steel mill," "municipal incinerator," "taconite ore processing plant," etc.), not by fuel choice.

Any other interpretation that avoids more stringent limits based on the applicant's desires would allow the "redefining the source" exception to swallow the rule that clean fuels must be considered as part of BACT.

The Court of Appeals for the Seventh Circuit has also strictly limited the "redefining the source" policy in a manner contrary to IEPA's interpretation here. The court held, in the context of a coal-fired power plant, that a permitting agency can decline to evaluate the use of low-sulfur coal only if the plant is sited and designed to receive all of its coal from an adjacent mine that the plant is physically connected to. *Sierra Club,* 499 F.3d at *656.*

Here, the TEC is not co-located with a mine and the gasification technology at issue are "feedstock flexible," as IEPA acknowledges in the Project Summary, page 24. In fact, the Summit Power Group has proposed an IGCC facility that would use similar Siemens gasifiers to gasify low sulfur Powder River Basin coal.[197] In addition, the purported changes to the feedstock, gasifier, and syngas conditioning trains that IEPA relies on to exclude cleaner fuels appear to be simply the minor changes that the Seventh Circuit has already opined do not constitute redefining the source. In particular, as that Court said:

> [s]ome adjustment in the design of the plant would be necessary in order to change the fuel source from high-sulfur to low-sulfur coal... but if it were no more than would be necessary whenever a plant switched from a dirtier to a cleaner fuel the change would be the adoption of a control technology.

Sierra Club v. EPA, 499 F.3d at *656.* In such cases, BACT must be based on burning the cleaner fuel; otherwise permitting agencies would effectively "read [clean fuels] out of the definition of [best available control technology.]" *Id.* IEPA's conclusion that the redefining the source policy allows for a different result is plainly contrary to law.

As for the CCA, CCG's desire to qualify as a "clean coal" facility (ironically, by using dirtier coal), does not justify foreclosing the use of cleaner fuels as redefining the source. At most, the ability under the CCA to force Illinois ratepayers to subsidize the TEC might be relevant to the economic analysis of cleaner fuels under Step 4 of the BACT analysis. It does not, however, justify simply ignoring cleaner fuels at the outset of the analysis.

IEPA's reliance on the CCA fails for a few other reasons. First, while the CCA has been signed into law, the Illinois General Assembly would have to pass additional legislation before CCG could force Illinois ratepayers to subsidize its plant. As such, the subsidy that CCG and IEPA are relying on here to foreclose evaluation of cleaner fuels is speculative at this point.

Second, to the extent the CCA or other state laws are read to foreclose the consideration of cleaner fuels, such laws run afoul of the Supremacy Clause of the U.S. Constitution, which "invalidates state laws that 'interfere with, or are contrary to, federal law." *Hillsborough County Florida v. Automated Med. Labs.*, Inc., 471 U.S. 707, 712 (1985). As explained above, the Clean Air Act requires that cleaner fuels be evaluated as a control option during a

[197]Summit Power Group, Texas Clean Energy Project — The Project, *available at* http://www.texascleanenergyproject.com/project/.

BACT analysis and be required if the use of cleaner fuels would cost-effectively reduce the emission of regulated air pollutants from a major source of pollution. If the CCA is read to foreclose such evaluation and use of cleaner fuels, then the state law would directly conflict with the Clean Air Act and, therefore, be invalid under the Supremacy Clause. *See, e.g., Clean Air Markets Group v. Pataki,* 338 F.3d 82, 87 (2d Cir. 2003).

Third, IEPA and CCG should not rely on the CCA to avoid evaluating and using cleaner fuels because such an interpretation would likely render the coal sulfur content provision of the CCA invalid under the Commerce Clause of the U.S. Constitution. In particular, CCG and IEPA are reading the CCA to require that the TEC use Illinois Basin coal and to foreclose the use of coal from other states or regions of the country. Such favoritism of in-state coal and discrimination against out-of-state feedstocks, however, would appear to conflict with the Commerce Clause, which bars economic favoritism between states. *See, e.g., Alliance for Clean Coal v. Miller,* 44 F.3d 591 (7th Cir. 1995); *Alliance for Clean Coal v. Bayh,* 72 F.3d 556 (7th Cir. 1995).

In short, neither the coal specifications of the CCA nor the relatively minor changes that would be needed for the TEC to operate on cleaner fuels justify dismissing cleaner fuels as somehow "redefining the source."

This comment generally takes issue with the IEPA's determination that the use of certain alternative fuels would fundamentally redefine the proposed source. Several legal arguments are presented in the comment regarding the redefining the source doctrine. Other legal arguments are presented as well, including challenges to the constitutionality of a state law that would attempt to further the development of this project and challenging CCG's reliance upon the state law as too speculative for purposes of the BACT analysis. Based on applicable law, the IEPA is obliged to reject each of these arguments.

In general, the BACT requirement of the PSD program does not authorize a permit authority to redefine the basic or fundamental design of a proposed source. *See, In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 136 (EAB 1999) (recognizing that "EPA has not generally required a source to change (i.e., redefine) its basic design."); *In re Prairie State Generating Co.*, 13 E.A.D. 1, 23 (EAB 2000). The NSR Manual, which USEPA has long employed as a guide to PSD permitting, recognizes the same tenet: "Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives." *NSR Manual* at B-13.

In recent guidance on the subject of GHGs, as provided below, USEPA retained the same aforementioned principle in discussing the framework of the BACT analysis. The concept that BACT should preserve the proposed source's fundamental purpose is thus well-settled.

> **While Step 1 is intended to capture a broad array of potential options for pollution control, this step of the process is not without limits. EPA has recognized that a Step 1 list of options need not necessarily include inherently**

> **lower polluting processes that would fundamentally redefine the nature of the source proposed by the permit applicant. BACT should generally not be applied to regulate the applicant's purpose or objective for the proposed facility.**
> ***See, PSD and Title V Permitting Guidance for GHGs,* (March 2011), citing *Prairie State.***

The EAB has generally observed that some "[design] aspects" of a project may be "beyond the reach of BACT" while other aspects are within its reach. *See, In re Northern Michigan University Ripley Heating Plant,* PSD Appeal No. 08-02, slip opinion at 26-27 (EAB 2009). The EAB has provided permit authorities with the following instructions in evaluating the fundamental purpose and design of a project in the BACT review:

> **…we conclude that the permit issuer appropriately looks to how the applicant, in proposing the facility, defines the goals, objectives, purpose, or basic design for the proposed facility. Thus, the permit issuer must be mindful that BACT, in most cases, should not be applied to regulate the applicant's objective or purpose for the proposed facility, and therefore, the permit issuer must discern which design elements are inherent to that purpose, articulated for reasons independent of air quality permitting, and which design elements may be changed to achieve pollutant emissions reductions without disrupting the applicant's basic business purpose for the proposed facility.**
> ***See, Prairie State,* 13 E.A.D. at 23.**

In its own review, the EAB lends a "central importance to 'how the permit applicant defines the proposed source's purpose or basic design'" and then offers a "hard look" to the argument. *See, Northern Mich. Univ.*, slip op. at 26.

In this instance, the IEPA has looked to CCG's purpose or basic design in evaluating BACT in at least two important respects, both of which reflect considerations that are independent of air quality. First, as previously mentioned, the design of the plant as a coal gasification plant, together with its attendant use of higher sulfur bituminous coal, is recognized as a fundamental aspect of the project. If the TEC were compelled to use a feedstock other than coal (e.g., biomass), such a mandate would clearly re-define the purpose or basic design of the source.

Secondly, the use of Illinois Basin coal has been selected to ensure the development of the TEC as a "clean coal facility" under the Illinois Clean Coal Portfolio Standard Law ("CCPSL"), 20 ILCS 3855/1-75, amended by P.A. 95-1027 (effective June 1, 2009). The legislation was aimed at making use of one of Illinois' most abundant energy resources for generating electrical power, with coal gasification offering distinct advantages over traditional generation in terms of improved efficiencies and enhanced environmental performance. The TEC will produce SNG for delivery to either a natural gas pipeline or a combined cycle power block located at the plant. In order to qualify for the CCPSL, the TEC must use higher sulfur bituminous coal (i.e., a minimum sulfur content of

1.7 lbs/mmBtu) in the production of SNG, as well as capture and sequester minimum percentages of CO_2 generated by the plant.[198]

CCG's goal of qualifying as a clean coal facility is well known and has been at the forefront of its efforts to obtain its most recent permitting approval. Mandating the use of an altogether different feedstock would interfere with, if not potentially end, CCG's pursuit of a key element of its business purpose. Similarly, mandating the use of lower sulfur coal would effectively change TEC's basic design, as the project would need to be fundamentally altered in order to accept coal or biomass that does not fulfill the CCPSL's statutory requirements.[199] This is the essence of redefining the source. *See, Prairie State,* 13 E.A.D. at 23 (upholding permit authority's determination that "the use of a particular coal supply is an inherent aspect of the proposed project"); *Northern Mich. Univ.,* at 26-27 (citing *Prairie State,* BACT does not mandate changes to a facility's basic design that "would call into question [its] existence").

The comments assert that a fuel change (and possibly even feedstock) does not constitute a redefinition of a proposed source unless, by chance, it affects only the project's "physical scope." This comment misconstrues the standard for determining whether an alternative clean fuel will redefine a project. As illustrated as recently as the EAB's Prairie State ruling, the proper test is one that looks to the basic purpose of the source [which is necessarily reflected in the project's design]. *See, Prairie State* at 24 (approving permit authority's conclusion that requiring a lower sulfur coal would redefine the source); *NSR Manual* at page B.13 (BACT does not require a proposed coal-fired power plant to consider natural gas); *Sierra Club v. EPA*, 499 F.3d 653, 655-656 (7th Cir. 2007)(BACT does not compel a coal-fired power plant to consider nuclear power or hydropower).[200]

This comment also argues that the CCPSL should not be evaluated in terms of the TEC project's purpose or intended design because additional legislation is

---

[198] **Incidentally, while the comments focus exclusively on the alleged air quality impacts from the higher sulfur content of the feedstock, the carbon capture and sequestration ("CCS") portion of the legislation is also an important element of the project. As a nascent technology that may offer future reductions of GHG to the atmosphere, CCS offers the potential for tremendous air quality improvements. With the passage of the CCPSL, the Illinois legislature has recognized that CCS is in the public interest and CCG has recognized that the eventual implementation of CCS to a project utilizing higher sulfur coal from the Illinois Basin region is a fundamental part of this project. To mandate the use of biomass or low-sulfur coal could frustrate the state legislature's objectives, defeat an important goal of the TEC project and ignore the potential for eventual implementation of CCS by the project, which, in turn, could drive future BACT analyses at other facilities. *See,* PSD and Title V Permitting Guidance for GHGs at 36 (recognizing a "number of ongoing research, development, and demonstration programs may make CCS technologies more widely applicable in the future. These facts are important to BACT Step 2, wherein technically infeasible control options are eliminated from further consideration. When considering the guidance provided below, permitting authorities should be aware of the changing status of various control options for GHG emissions when determining BACT.")(footnote omitted).**

[199] ***See,* Project Summary at 25.**

[200] **The comments cite *In re Hibbing Taconite*, 2 E.A.D. 838 (Adm'r 1989), to support their position. However, the holding from this early case on the issue of redefining the source had not been raised by the parties and has since been clarified by *Prairie State* and other rulings in recent years. Moreover, the Administrator's ruling noted that the alternative fuel would not "require any fundamental change to Hibbing's product, purpose, or equipment." *Id.* In this instance, an alternative feedstock would fundamentally change TEC's stated purpose and intended design. The comments also attempt to limit the scope of the redefining the source doctrine by suggesting that it only applies where a proposed coal-fired facility is a mine-mouth power plant. The *Sierra Club* ruling, cited by the comments for this proposition, does not contain this limitation and, further, the ruling upheld the EAB's rationale that BACT did not require an applicant to redesign the "proposed facility" by altering its "fundamental scope." 499 F.3d at 657.**

needed before it can qualify as a clean coal facility and reliance on the statute is therefore "speculative." The IEPA disagrees. Both CCG and the IEPA have properly considered the effects of the state legislation, which has remained in effect throughout the pendency of the permit application, in a manner fully consistent with the requirements of BACT. Even though CCG may not yet qualify for the incentives offered by this state law, it has undoubtedly designed the TEC project with the statute's goals and requirements in mind. To the extent that this intended design and stated business purpose is relevant in evaluating BACT, the state law and the resulting reliance by CCG and the IEPA on its existence should not be so casually dismissed.

Lastly, the comments contend that the CCPSL violates both the Commerce Clause and the Supremacy clauses of the United States Constitution. As an initial matter, the enactment of the state legislation is presumed constitutional. *See, People v. Carpenter,* 228 Ill.2d 250, 267 (Ill. 2008). In addition, the IEPA, as an arm or instrumentality of Illinois state government, is obliged to respect both the presumed constitutionality and facial validity of the statute in performing its licensing duties under applicable state law requirements and the federally delegated PSD program.

Moreover, it is not clear how the CCPSL must fail under either of the constitutional arguments raised in the comment. The CCPSL does not require TEC to use exclusively coal from Illinois but, rather, merely specifies the use of bituminous coal from the Illinois Basin containing a sulfur content greater than 1.7 lbs/mmBtu. *See,* 20 ILCS 3855/1-10. The design coal for the TEC project is Illinois Basin coal, which is commonly found in Illinois, Indiana, and Kentucky. Nothing in the state law mandates that the TEC project be restricted to Illinois coal and, for that reason, the CCPSL does not prohibit or impede the use of coals from outside Illinois in violation of the Commerce Clause.[201]

The CCPSL also does not interfere with or supplant the requirements of the Clean Air Act. The Project Summary and these responses have described in considerable detail how the BACT evaluation for the TEC has demonstrated compliance with applicable law and related interpretations of that law, including EAB rulings and USEPA guidance. CCG's effort to qualify as a "clean coal facility" under the CCPSL is a legitimate business purpose that is relevant for purposes of the BACT analysis, as PSD's requirements are interpreted as intending the perseveration of the fundamental purpose or design of a proposed source. As the TEC project has recognized the CCPSL as central to its business objective and design, the consideration of the effects of the

---

[201] **Additionally, this argument appears to implicate the "dormant commerce clause" line of cases that focus on States' attempts to ban or impose burdens on out-of-state products or commerce. *See, Oklahoma Tax Comm'n v. Jefferson Lines, Inc.*, 514 U.S. 175, 179 (1995). This limitation on the States' power, however, is recognized by courts as "by no means absolute," with States retaining their general police powers to regulate areas of "legitimate local concern" in the absence of conflicting federal laws, notwithstanding effects to interstate commerce. *See, Lewis v. BT Investment Mgrs., Inc.*, 447 U.S. 27, 36 (1980). Where the state law does not directly discriminate against interstate commerce but instead "regulates evenhandedly and only indirectly affects interstate commerce," the courts use a balancing test to determine whether the statute violates the Commerce Clause. *See Brown-Forman Distillers Corp. v. New York State Liquor Auth.*, 476 U.S. 573, 579 (1986). This balancing test is "whether the State's interest is legitimate and whether the burden on interstate commerce clearly exceeds the local benefits." *Id.* In this instance, the state law does not require the exclusive use of Illinois coal and does not overtly discriminate against out-of-state coal. The legitimate benefits of the CCPSL (i.e., promoting use of abundant natural resources, encouraging development of clean coal facilities and innovations, fostering CCS) also appear to far outweigh any theoretical imposition on interstate commerce.**

state law can be said to fit neatly into the construct of federal law. As a consequence, the CCPSL does not displace the Clean Air Act and, in fact, is perfectly consistent with its requirements.[202]

As discussed, the basic "purpose" of the TEC and its "basic design" are highly relevant when determining the proper scope of BACT review. Requiring TEC to use a different feedstock would re-define the source because certain fundamental elements of the TEC project dictate use of Illinois Basin coal as the feedstock. Moreover, CCG has proposed the use of Illinois Basin coal for reasons independent of air quality permitting, and to require a different feedstock would disrupt -- if not frustrate altogether -- the TEC's basic business purpose. *See Prairie State*, 13 E.A.D. at 23 (upholding the IEPA's conclusion that "the use of a particular coal supply is an inherent aspect of the proposed project.").

TEC is a facility that will produce SNG for delivery either to a natural gas pipeline or to the combined cycle power block on site. TEC is <u>designed</u> to be a "clean coal facility," as that term has been defined the Illinois Clean Coal Portfolio Standard Law (20 ILCS 3855/1-75, as amended by P.A. 95-1027, effective June 1, 2009) ("CCPSL"). To qualify as a clean coal facility, TEC must use typical, higher sulfur coal from the Illinois Basin, while capturing and sequestering minimum percentages of CO_2 generated by the facility. TEC's qualification as a clean coal facility is a fundamental basis of the project's business purpose. *See Northern Mich. Univ.*, slip op. at 26-27 (BACT does not require changes to a facility's basic design that "would call into question [the facility's] existence.") (citing *Prairie State*).

While the comment focuses only on air quality impacts from the sulfur content of the feedstock, coal gasification and carbon capture and sequestration ("CCS") are critical to the project. Both coal gasification and CCS have the potential for significant positive impacts on air quality and the environment. Coal gasification is a promising technology to be able to use Illinois Basin coal with far less emissions of traditional pollutants to the atmosphere than the boiler technology now commonly used by coal-fired power plants. Coal gasification is very effective in controlling the sulfur that is present at high levels in most of the coal reserves in the Illinois Basin. CCS is a promising technology to reduce emissions of GHG to the atmosphere. The Illinois legislature confirmed by adoption of the CCPSL that coal gasification accompanied by

---

[202] It can also be noted that the legislative history underlying the Clean Air Act's BACT definition offers further support for this conclusion. The original 1977 legislative history reveals a congressional intent to promote, rather than restrict, the use of available coal. Notably, Senator Huddleston expressed concern that BACT "not inhibit . . . continued development in making coal a clean burning, acceptable fuel. . . . I believe everybody recognizes . . . that the central part of our energy effort has to be the greater utilization of coal." 123 Cong. Rec. S9434 (Daily Ed. June 10, 1977), *reprinted in* 3 *A Legislative History of the Clean Air Act Amendments of 1977*, 95th Cong., 2d Sess., Serial No. 95-16, at 1053 (1978). When Congress added "clean fuels" to the BACT definition in 1990, the Senate Committee Report again evidenced an intention that BACT was not intended to impede an applicant from selecting a feedstock consistent with the fundamental purpose of the proposed source. As excerpted from the Report: "Subsection (d) amends section 169(3) of the Act to insert the words "clean fuels," after "including fuel cleaning" as part of the Best Available Control Technology (BACT) determination under Prevention of Significant Deterioration provisions. The intent of this amendment is to continue the requirements for case-by-case determinations of BACT as in current law. The Committee intends that the amendment will not result in an increase in the level of emission rates found to meet BACT, when compared on a case-by-case basis to BACT determinations under current law. The Administrator may consider the use of clean fuels to meet BACT requirements if a permit applicant proposes to meet such requirements by using clean fuel. In no case is the Administrator compelled to require mandatory use of clean fuels by a permit applicant." *See,* Senate Report No. 101-228, at 338 (1989); *reprinted in 5 A Legislative History of the Clean Air Act Amendments of 1990*, 103rd Cong., 1st Sess., S. Prt. No. 103-38, at 8678 (1993).

CCS is in the public interest. Coal gasification at a utility scale on higher sulfur coal from the Illinois Basin, incorporating CCS, constitute fundamental aspects of this project. To require use of biomass or low sulfur coal from Illinois or elsewhere would defeat an important goal of the TEC project and the objective of the Illinois legislature. Indeed, successful use of coal gasification and CCS at TEC has the potential for substantial reductions in emissions of pollutants, particularly GHG. As such, the TEC project could drive future BACT analyses and GHG control requirements for subsequent new facilities.[203]

Certainly coal gasification technology, as would be used at the TEC, offers a means to utilize one of Illinois' abundant mineral resources to generate electricity, albeit with advantages over traditional methods due to improved environmental performance and potential improvements in efficiency. The pursuit of gasification and CCS technologies in Illinois is consistent with the General Assembly's enactment of various state laws and policies that fund research and promote the development and use of both Illinois coal and coal gasification. Mandating the use of feedstocks other than higher sulfur bituminous coal would thwart these worthy goals and would inappropriately constrain the proposed plant. It would also act to deprive Illinois residents and the nation of emerging technologies at a time when both innovation and increased diversity is being sought for the technologies that supply electricity and other forms of power.[204] As such, requiring a lower sulfur feedstock would re-define the source because TEC's fundamental design would have to be altered to accept coal or biomass not meeting the requirements of the CCPSL. *See* Project Summary at 25.

1. *"Clean Fuels" May Be Rejected On Grounds Other Than Cost in Step 4.*

The comment further asserts that clean fuels can be eliminated as a control option only for cost reasons under Step 4 of the top-down BACT analysis. First, as noted above, the initial inquiry is whether alternative fuels or feedstocks would re-define the proposed source. Use of different feedstocks would frustrate CCG's basic purpose for the plant. Second, alternative feedstocks can be, and were, also ruled out on other grounds including feasibility, suitability, and effectiveness in reducing emissions. Project Summary at 24-26. Finally, as part of the analysis of lower-sulfur Powder River Basin and subbituminous coals, the increased costs of the gasification technology for those feedstocks was considered. Project Summary at 26 n.18.

2. *The CCPSL Is An Appropriate Business Objective for CCG Even Though TEC Has Not Yet Qualified For Its Incentives.*

The comment asserts that IEPA may not consider the CCPSL in analyzing the business purpose and objectives of CCG for the proposed TEC because

---

[203] *See* GHG BACT Guidance at 36 ("A number of ongoing research, development, and demonstration programs may make CCS technologies more widely applicable in the future. These facts are important to BACT Step 2, wherein technically infeasible control options are eliminated from further consideration. When considering the guidance provided below, permitting authorities should be aware of the changing status of various control options for GHG emissions when determining BACT.") (footnote omitted).

[204] It must be noted that alternative feedstocks were evaluated in the BACT analysis even though there was no requirement to do so. The comment is incorrect that "cleaner" feedstocks were not evaluated.

additional legislation is required before CCG can qualify for the CCPSL's incentives. The comment thus characterizes the goals of CCG as speculative.

The business purpose of the facility was appropriately considered in the BACT analysis. TEC would be developed to qualify as a "clean coal facility" under the CCPSL. This represents a fundamental business purpose of the proposed source, and it is being designed accordingly. It is immaterial whether all the prerequisites necessary to achieve this business objective have been satisfied. The prospective success or failure of the business enterprise is beyond the scope of the BACT analysis, and it is not the permitting authority's role to evaluate the likelihood of successful realization of the applicant's goals. In this instance, qualification under the CCPSL is a legitimate business purpose, and the permitting authority is not required by BACT to force the applicant to alter the fundamental purpose of the proposed source.

Finally, the comment uses the terms "feedstock" and "fuel" as if they are interchangeable but this is not the case. It is also significant that the term feedstock, rather than fuel, is used in this response. In the gasification block at the TEC, coal would be converted to another form of fuel, SNG, that would only then be used as fuel and combusted. From this perspective, the gasification block would be a "fuel conversion plant" that uses coal as its feedstock. As such, requiring a different feedstock for the gasification block would even more clearly redefine the nature of the planned fuel conversion plant.

53. Biomass material could be used to reduce emissions. CCG's BACT analysis did not discuss the use of biomass as a feedstock alternative. The IEPA Project Summary, on the other hand, makes four general arguments against biomass: (1) not a suitable feedstock; (2) large-scale farming not feasible; (3) large-scale biomass gasification not feasible; and (4) no improvement in emissions.[205] None of these arguments is supported and none is correct.

First, the Project Summary argues that biomass is not a suitable feedstock for gasification due to its composition and properties. An entire textbook has been devoted to the subject.[206] Further, the Siemens gasifiers proposed for the TEC are widely touted by Siemens itself as being able to gasify a wide range of feedstocks, including biomass.[207]

One recent example of biomass gasification is the announcement by Progress Energy Florida that it signed another contract with Biomass Gas & Electric LLC ("BG&E") to purchase electricity from a waste-wood biomass plant planned for Florida. This was the second biomass gasification plant that BG&E signed a contract to build, and the company proposes to build a total of four. The Progress Energy plant, which will be built in north or

[205] Project Summary, p. 26.
[206] Prabir Basu, Biomass Gasification and Pyrolysis: Practical Design, Elsevier, 2010.
[207] Siemens, Integrated Gasification Combined Cycle ("A great advantage of the Siemens fuel gasifier (SFG) is the wide range of fuels it can handle, including coal, biomass, waste, petroleum coke, refinery residues as well as a blend of these fuels."), *see* http://www.energy.siemens.com/br/en/power-generation/power-plants/integratedgasification-combined-cycle/integrated-gasification-combined-cycle.htm#content=Flexibility%20 (Commenter's Exhibit 45); Harry Morehead, Gasification Can Play a Key Role in Energy Independence, May 26, 2010, p. 25. http://www.usea.org/Programs/CCSBriefings/documents/SiemensPresentation-Morehead.pdf, (Commenter's Exhibit 46); Siemens, Siemens Fuel Gasification Technology at a Glance, 2008, p. 4; http://www.dvv.uni-duisburgessen.de/download/pdf_34Fach/Siemens_P5.pdf, (Commenter's Exhibit 47).

central Florida, will use waste wood products—such as yard trimmings, tree bark, and wood knots from paper mills—to create electricity. The gasification process would supply sufficient gas to generate about 153 MW. The plant will use gasification and projected commercial operation is expected is projected to begin in June 2011. Progress Energy has another biomass project in the Carolinas with 73 MW.[208]

Second, the Project Summary, page 26, falsely asserts that farming to produce low quality biomass feedstocks is not available. There is no support for this statement and it is incorrect.[209] Further, there is extensive world-wide precedent for using biomass as part of the feedstock.[210]

Third, the Project Summary asserts that large scale gasification is not feasible. As discussed above, Siemens, the provider of the gasifiers, asserts they can gasify biomass without any limitation on size.

Finally, the Project Summary asserts that no improvement in emissions would be achieved as emissions from the TEC are well controlled. This is false, as abundantly demonstrated by the Application itself (and also admitted elsewhere in the Project Summary, at 22). First, startups, shutdowns, and malfunctions will occur, which will send untreated, raw gases directly to the flare without any treatment. While these events would potentially only occur during 10% of the operating hours, the emissions during these events are very high. In these cases, the otherwise good treatment is irrelevant.

These flaring events would be the major source of criteria pollutant emissions at the TEC, releasing, among others, at least 551 ton/yr of SO_2 and 315 ton/yr of CO.[211] Further, the TEC will emit over 5 million tons of GHG, the majority through the uncontrolled AGR CO_2 vent.[212] If low-impact biomass were used to satisfy some or all of the facility's feedstock requirements, the plant would produce fewer emissions of GHG, HAPs, SO_2, H_2S, sulfuric acid mist, and other pollutants.

A proper top-down BACT analysis must consider low-impact biomass inputs into the gasification process as opposed to coal alone. There is already a substantial amount of installed biomass capacity in the country, with forest products and agricultural residues representing potential sources of biomass. And biomass gasification has already been demonstrated as a feasible technology.

In order to satisfy CAA requirements, IEPA must require CCG to submit an evaluation of biomass as part of the BACT analyses for the TEC. IEPA can allow TEC to avoid using biomass only if CCG can demonstrate, and IEPA can independently confirm, that the cost of

[208] See Green Energy News, Florida Public Service Commission (PSC) Approves 20-Year Progress Energy/BG&E Renewable Energy Contract, 2008, Vol. 12 No. 47, February 13, http://www.green-energy- news.com/nwslnks/clips208/feb08014.html, (Commenter's Exhibit 48); and Progress Energy, Biomass http://www.progress-energy.com/commitment/energy-forum/energy-resources/biomaa.page (Commenter's Exhibit 49);
[209] New Energy Farms, http://www.newenergyfarms.com/site/index.php Large Scale Production of Biomass in Mozambique for the Dutch Market, http://www .agentschapnl.nl/en/node/104588.
[210] Mark Mba Wright Techno-Economic and Environmental Opportunities for Biomass Heat and Power Generation, Prepared for Plains Justice, October 14, 2010, (Commenter's Exhibit 135); Co-Firing Biomass with Coal: A Success Story, (Commenter's Exhibit 135a); Thermal Net, Workshop on Biomass Co-Processing and Co-Firing, April 5, 2006, (Commenter's Exhibit 135b); Mitsui Babcock Biomass Co-Firing Experience from the UK, (Commenter's Exhibit 135).
[211] Ap., v. 1, Table 3-2, Flare.
[212] Ap., v. 3, Table 3-3, Source-Wide Total.

pollutant removal from using such fuel is "disproportionately high when compared to the cost of control for that particular pollutant and source in recent BACT determinations.[213]

The Project Summary is supported by the permit record and accurately explains why biomass is not an appropriate alternate feedstock for the TEC. The use of biomass was considered and rejected as an alternative feedstock in the BACT analysis for multiple reasons, and the most significant were discussed in the Project Summary. In this response, the IEPA does not revisit the determination that biomass is not a viable or feasible alternative feedstock for the TEC for the purposes of reducing emissions, but only addresses the specific points raised by this comment.

The Project Summary does not suggest that biomass is unsuitable for all types of gasification processes and projects. Biomass is practical as a feedstock for certain applications of gasification technology but the TEC is not one of those applications, as it entails use of gasification for production of SNG. The manufacture of SNG and other specific chemicals using synthesis gas produced by gasification necessitates a stable feedstock with consistent properties so as to produce a consistent synthesis gas. In this regard, CCG indicates that it is not aware of any gasification technology offerings that would be suitable for the production of SNG from biomass.[214] Biomass would only be a viable feedstock for the TEC if a high-temperature, high-pressure gasification process were available to produce enough high quality syngas to be processed in the various units in the gasification block.[215] No such gasification process is available or feasible at this time.

The specific examples cited by the comment do not demonstrate that biomass is technically feasible for the TEC. While Siemens gasifiers are fuel-flexible and can use biomass as a feedstock in certain applications, utilizing 100% biomass is not commercially offered or proven.[216] The comment also cites examples of biomass gasification projects for power generation being developed by Progress Energy in Florida and North Carolina. First, the comment's reference to the 153 MW electrical output from the Biomass Gas& Electric (BG&E) site in Tallahassee, Florida is not correct. The BG&E facility will actually only produce 41 MW on a net basis using a single Rentech SilvaGas gasifier supplied with 730 tons per day of biomass wood chips.[217] The reference to 152 MW of power generation from biomass by Progress Energy in Commenter's Exhibit 49 is referring to the combined generation of multiple plants and not output from BG&E. In addition, Rentech SilvaGas gasifiers are low temperature, atmospheric pressure gasifiers that are capable of using only biomass as

---

[213] NSR Manual, pp. B.31-.32.

[214] **Unlike the small atmospheric gasification processes that can use biomass as a feedstock in waste-to-energy applications, the TEC gasification block must be able to produce enough SNG to supply a power block with an output of at least 500 MW (refer to the project definition in Section 5.2 of Volume 1 to the Application which defines the key design elements of the TEC that must be considered in any evaluation of alternative fuels). This requires high temperature, high pressure, oxygen-blown gasifiers. By contrast, most commercial biomass gasification technologies operate at relatively low temperatures and are air-blown. The syngas produced in these low temperature, air-blown gasifiers contain tars and aromatic organic compounds that are incompatible with TEC's process. The syngas would cause fouling if fed to the various catalyst beds and heat exchangers in the gasification block, resulting in short run lengths and poor performance during operational periods.**

[215] **Commenters' Exhibit 135b includes a slide on page 46 showing that pressurized gasifiers are the only type of gasification technology that can be used to supply syngas or SNG to a combustion turbine.**

[216] **Haberzettl, Anton, *Siemens Fuel Gasification Technology at a Glance*, Siemens Energy Sector E/F Presentation, p. 12.**

[217] **Biomass Gas & Electric, Air Construction Permit Application for the Tallahassee Renewable Energy Center, April 2008, available at http://www.dep.state.fl.us/Air/emission/bioenergy/tallahassee.htm.**

a feedstock.[218] SilvaGas gasifiers produce what BG&E refers to as "product gas" and not syngas that would be suitable for conversion into SNG. Thus, the BG&E facility is not similar to the TEC in any way and does not demonstrate that biomass gasification is a viable technology for large-scale SNG production and power generation. Regardless, BG&E has cancelled its Florida power plant project.[219] The 73 MW Progress Energy project in North Carolina cited by the comment is actually two projects, one with a 43 MW capacity and another with a 25 MW capacity.[220] These projects use similar biomass gasification technology to the Progress site in Florida, and do not show that biomass gasification is feasible for the TEC.

The comment is also incorrect that Siemens dry-feed gasifiers can be used in large-scale gasification projects without any restriction on size in terms of the syngas output. The relevant factor for the amount of biomass that can be fed to a Siemens gasifier in a blended feedstock application is the ability to appropriately dry, mill, and size the biomass so that it can be fluidized and pneumatically conveyed along with the primary feedstock to the gasifier main burner. If the biomass physical characteristics do not allow it to be fluidized properly, then it cannot be used as an alternate feedstock for blending in the current design of a Siemens gasifier.

Blending biomass and coal feedstocks is impractical, and is not demonstrated on a facility such as the TEC. Biomass would have to be fed to a parallel milling and drying process that operated in conjunction with the milling and drying process for coal at the plant.[221] Simultaneously ensuring that the coal and biomass properties are within the design specifications for the gasifier using two independent milling and drying processes would be an extremely complex endeavor that would likely create increased unplanned outages of the gasifiers due to problems with the consistent of feedstock fed to the gasifiers. Such a system is not demonstrated in practice as a control measure for reducing emissions, including emissions of GHG, at any operating gasification facility, thus, it is not a technically feasible control option for the TEC.[222] Even assuming that the biomass milling and drying system, gasifier feed system, and gasifiers could be designed and operated to supply a consistent amount of syngas with a minimally varying composition and quality to the syngas processing train and methanation unit, the gasification block would have to be completely redesigned to accommodate a blended coal/biomass feedstock while still ensuring the design requirements of the power block specified in the project definition were not altered. This is not required by BACT because such a design is neither demonstrated nor commercially available. As such, biomass was appropriately eliminated as a control option for further consideration in the BACT analysis.

---

[218] **http://www.rentechinc.com/silvaGas.php**

[219] BG&E, Permit Application Withdrawal Letter, February 2, 2009, available at http://www.dep.state.fl.us/Air/emission/bioenergy/tallahassee.htm

[220] www.progress-energy.com/commitment/corporate-responsibility-report/environment/renewableenergy.page

[221] **The Project Summary discussed the operational issues associated with such a parallel feed system in conjunction with the use of low sulfur coal as an alternate feedstock during startup (Project Summary page 38).**

[222] **The Ohio River Clean Fuels facility proposed by Baard Energy to produce synthetic diesel and jet fuel has indicated that this proposed facility would be designed to use about 10 percent biomass as feedstock, on an energy equivalent basis. However, the permit for the proposed Ohio River facility also does not demonstrate that TEC's feedstock should be supplemented with biomass. First, Baard has not committed nor is it required by its construction permit to use any biomass as a feedstock. Second, the viability and feasibility of the proposed Ohio River facility, with or without supplemental use of biomass, is not demonstrated since the project has not selected an EPC contractor and has not received financing (http://www.baardenergy.com/orcf.htm). Lastly, the proposed Ohio River facility would make synthetic liquid fuels using the Fischer-Tropsch process, which is significantly different from making SNG from syngas using Methanation.**

Biomass is further not a feasible control option for the TEC due to a lack of adequate sources of biomass. The comment provides several references purporting to refute the Project Summary on this point, but those references do not establish the viability of biomass resources for the TEC. The first reference to the New Energy Farms website suggests that perennial grasses such as Miscanthus or switchgrass should have been considered as a candidate biomass feedstock for the TEC.[223] In August 2011, the U.S. Department of Energy (DOE) Office of Energy Efficiency & Renewable Energy published a comprehensive document entitled *U.S. Billion-Ton Update: Biomass Supply for a Bioenergy and Bioproducts Industry* which provides forecasts for the amount of biomass resources of various types that would be available in the U.S between now and 2030.[224] The study includes biomass supply forecasts for all major primary and secondary forest and agriculture residue feedstocks, major waste feedstocks, and energy crops grown specifically for bioenergy. At the highest future price for energy crops evaluated, the DOE does not forecast any significant quantities of perennial grasses to be produced in Illinois even by 2030.[225] In 2012, DOE does not forecast any energy crops to be planted in the U.S., despite representations on a single company's website that Miscanthus and other perennial grasses have been planted in Illinois and other Midwestern states in very small quantities.[226] Even if perennial grasses could be converted into a useable feedstock for the Siemens gasifiers selected for the TEC and this feedstock could be reliably sourced from the Southeast or Great Plains states that are expected to be producing most of the available energy crops in 2030, CCG would have to obtain the equivalent of more than 24,000 acres (38 square miles) of energy crop land per year to supply the gasifiers with just 10 percent of their design heat input.[227] Harvesting crops from such a large area and transporting the harvested biomass hundreds of miles to the TEC would not be logistically possible without a market and distribution system for obtaining a stable and consistent supply of biomass feedstock. This market does not exist today, and may not exist in the future if biomass prices do not meet the targets set by DOE in its forecasts. Such a market and distribution system exists for coal, which is the only viable feedstock for the TEC to meet CCG's objectives for the project.

The next reference cited by the comment is a link to a conference webpage for the Ministry of Economic Affairs, Agriculture, and Innovation of the Netherlands and is entitled *Large Scale Production of Biomass in Mozambique for the Dutch Market.*[228] The objective of the conference held on February 8, 2011 was to discuss the concept of

---

[223] **Sierra Club/Natural Resources Defense Council, Comments, January 3, 2012, p. 50.**

[224] **U.S. Department of Energy, *Office of Energy Efficiency & Renewable Energy, U.S. Billion-Ton Update: Biomass Supply for Bioenergy and Bioproducts Industry*, August 2011, available at http://www1.eere.energy.gov/biomass/pdfs/billion_ton_update.pdf**

[225] ***Ibid.* Figure 5-19 Estimated state shares of energy crops and agricultural residues supplies at farmgate prices of $40, $50, and $60 per dry ton in 2030, p. 133.**

[226] ***Ibid.* Table ES.1 Summary of Currently Used and Potential Forest and Agriculture Biomass at $60 per Dry Ton or Less, under Baseline and High-Yield Scenario Assumptions, p. xxv.**

[227] **The gasifiers at the TEC would have the capability of producing approximately 1.4 million pounds of raw syngas per hour (220-CAAPP Form for the Gasification and Raw Treatment Area in Appendix A of Volume 1 to the Application) which translates to a total heat input requirement to the gasifiers of 3,780 mmBtu based on a raw syngas heating value of 0.0027 mmBtu/lb (refer to Section C-22 of Appendix C to Volume 1 of the Application). Based on an average biomass heating value of 15 mmBtu/dry ton (from page 151 of the DOE U.S. Billion Ton Update study), CCG would have to feed 25 tons per hour of biomass to the gasifiers to meet just 10% of the overall heat input requirement for the gasifiers. Assuming continuous operation on an annual basis at this biomass feed rate, CCG would consume 220,752 ton per year of biomass annually. The DOE study projects the highest productivity for perennial grasses for any farmland in the U.S. is expected to be 9 tons per acres. At this productivity level, more than 24,000 acres (38 square miles) of cropland would have to be harvested annually to supply the gasifiers with a minimal amount of biomass feedstock.**

[228] **Sierra Club/Natural Resources Defense Council, Comments, January 3, 2012, p. 50.**

a feasibility study conducted on large scale biomass production in Mozambique for the import market of the Netherlands to support a bio-based economy. Any results of this feasibility study are future looking, speculative and not relevant for a coal gasification facility located in Illinois. The comment's suggestion that CCG should have considered importing biomass from Africa to supply the TEC's gasifiers ignores the more relevant results of much more comprehensive studies developed by the U.S. DOE.

The remaining references cited to support the argument that "there is extensive world-wide precedent for using biomass as part of the feedstock" all relate to biomass co-firing in coal boilers or biomass gasification to produce product gas which is fed to a conventional coal boiler. Co-firing biomass in a conventional or circulating fluidized bed boiler does not pose the same technical challenges as using a blended feedstock in high temperature gasifiers like those proposed at the TEC.[229]

The size of the TEC is a critical factor that must be considered in the BACT analysis. In contrast to the small 10 to 80 MW_{th} gasifiers identified by the comment for biomass gasification in limited applications at coal-fired power plants, the Siemens gasifiers at the TEC have a rating of 500 MW_{th} or roughly 6 to 50 times larger than the commercial biomass gasification technology offerings available today. To meet the size requirements for the facility, CCG would have to operate numerous gasifiers in parallel which is not a demonstrated or practical design configuration. Indeed, the energy research agency for the Netherlands government has published conceptual design studies investigating possible plant configurations for producing SNG from biomass, but the agency has recognized that the technologies required for these designs are not commercially available, further supporting the conclusion that biomass is not technically feasible for the TEC at this time.[230] [231]

Moreover, as acknowledged by the comment, the use of biomass as a feedstock would not result in noticeable emissions improvements during normal, steady-state operation of the gasification block. Theoretically, using biomass as part of a blended feedstock could potentially reduce emissions of pollutants from the gasification block during startup, shutdown, and some malfunctions. However, use of biomass as a supplemental feedstock during these limited, short-term periods is hypothetical and not a demonstrated, technically feasible option for the reasons previously stated.

---

[229] **Commenter's Exhibit 135a, entitled *Co-firing Biomass with Coal: A Success Story*, is a one page summary of efforts by the International Energy Agency (IEA) to collect, analyze, and disseminate strategic technical and non- technical information on biomass combustion and co-firing applications with the objective of leading to increased use of bioenergy technologies and concepts.[229] This IEA summary highlights the number of conventional coal-fired power plants worldwide that have utilized some amount of biomass-co-firing at some point in time for some unknown duration. This paper does not state the amount of biomass co-firing as a percentage of the overall heat input to the boiler that was achieved and what the outcome of the co-firing trials were in terms of operational issues that may have been caused by the use of this alternate fuel. The report also mentions biomass gasification as another option for utilizing biomass to produce energy and specifically points to the Zeltweg plant in Austria, the Lahti plant in Finland, and the AMERGAS project in the Netherlands. These facilities do not lead to the conclusion that sufficient biomass is available for the TEC to produce SNG. as they use atmospheric pressure, low temperatures gasification technology. *See* Granatstein, D.L., Natural Resources Canada/CANMET Energy Technology Centre (CETC) for IEA Bioenergy Agreement – Task 36, Case Study on BioCoComb Biomass Gasification Project – Zeltweg Power Generation, Austria, September 2002, available at http://www.ieabioenergytask36.org/Publications/2001-2003/Case_Studies/Case_Study_on_BioCoComb_Biomass_Gasification_Project.pdf**

[230] **Energy Research Centre of the Netherlands, *Production of Synthetic Natural Gas (SNG) from Biomass: Development and Operation of an Integrated Bio-SNG System* (ECN-E--06-018), September 2006, available at http://www.ecn.nl/docs/library/report/2006/e06018.pdf.**

[231] **Energy Research Centre of the Netherlands, "*Green Gas" as SNG a Renewable Fuel with Conventional Quality* (ECN-RX--04-085), August 2004, available at http://energie.nl/pub/www/library/report/2004/rx04085.pdf.**

Due to the numerous technical issues associated with using biomass as a feedstock for the TEC, the BACT analysis did not proceed past step 1 because the use of biomass as an alternate feedstock was not considered an "available" control option. Even if the limited R&D conducted to-date for biomass gasification in large-scale, high temperature, high pressure gasifiers could be used to support an argument that this technology is "available," it would be eliminated in step 2 as technically infeasible for the TEC, since an entirely separate biomass milling and drying train would have to be operated in conjunction with the a parallel coal milling and drying train. This parallel gasifier feed train configuration is expected to cause long-term operational issues that render this option technically infeasible pending successful, future R&D efforts by Siemens, other large-scale coal gasifier vendors, independent research organizations, and U.S. DOE.[232] [233] [234] The DOE fully acknowledges the challenges associated with a blended feedstock application for large-scale gasifiers when they state: "several challenges related to biomass utilization have been observed. A primary challenge related to biomass utilization in large scale commercial [coal/biomass-to-liquids] CBTL is the ability to reliably feed a variety of biomass feedstocks to the gasifier as biomass-coal mixtures."[235] To overcome these notable challenges, DOE National Energy Technology Laboratory (NETL) in conjunction with Southern Research has commissioned pilot-scale studies that will potentially allow gasification systems to operate with blended feedstock gasifier feed systems in the future, but this technology is not available, demonstrated, or technically feasible today at the scale required for the TEC (and may never be if the R&D efforts on this technology are not successful).

54. The BACT analysis did not evaluate lower sulfur coal as a feedstock for gasification. Rather, the application states, without support, that the TEC would not be economically feasible without CCA support, which mandates the use of Illinois Basin Coal with a sulfur content of at least 1.7 pound per mmBtu.[236] The Project Summary, page 22, on the other hand, asserts that emissions from the gasification process are independent of the composition of the feedstock and depend only on the design and performance specifications for the gasification process. These arguments are unsupported and incorrect.

First, IEPA on Project Summary, page 25, claims that use of a different, lower-sulfur feedstock would likely not provide significantly lower emissions. As explained above, however, emissions from the gasification process do depend on the composition of the feedstock. The majority of the SO_2, CO, HAPs, and other emissions occur during startups, shutdowns, and malfunctions when raw untreated or partially treated gases are sent directly to the flare. When this occurs, the design efficiency of the gas treating system is irrelevant. In this case, the composition of the flared gases depends directly on the composition of the feedstock. Substances in the coal are converted into gases in the gasifier. Organic and inorganic sulfur, for example, are converted into SO_2, a gas. Trace metals, such as mercury,

---

[232] **Southern Research** , ***Environment & Energy, Syngas Cleaning, Thermochemical Conversion, Feedstocks and Feeders*****, available at http://www.southernresearch.org/environment-energy/thermochemical-conversion/feedstock-and-feeders**

[233] **U.S Department of Energy National Renewable Energy Laboratory,** ***Cost and Performance Analysis of Biomass-Based Integrated Gasification Combined-Cycle (BIGCC) Power Systems*** **(NREL/TP-430-21657), October 1996.**

[234] **U.S Department of Energy National Energy Technology Laboratory,** ***Demonstration of a Piston Driven Plug Feed System for Feeding Coal/Biomass Mixtures across a Pressure Gradient for Application to Commercial CBTL Systems*****, February 2012, available at http://www.netl.doe.gov/publications/factsheets/project/NT0006523.pdf.**

[235] ***Ibid*****.**

[236] Ap., v. 1, p. *5-7.*

lead, and cadmium present in the coal are converted into volatile gaseous forms and emitted in the gases. The majority of the emissions occur during these flaring events. Thus, coal composition has a direct and significant impact on emissions.

For example, the use of a lower sulfur coal would significantly lower SO_2 emissions. Based on the Draft Permit, the potential SO_2 emissions of the TEC would be 697 ton/yr of SO_2, with permitted maximum hourly emissions of 9,036 lb/hr. The amount of SO_2 that would be emitted from the TEC would be directly proportional to the amount of sulfur that enters the gasifiers in the coal. The application did not disclose the sulfur content assumed in the emission calculations. In my above comments, I back calculated that the flaring SO_2 emissions assumed 3.75% sulfur in the coal. The flaring emissions make up 79% of the total SO_2 emissions. Elsewhere, findings in the Draft Permit disclose a nominal coal sulfur content of 4.22%. There are many lower sulfur coals available to CCG.

CCG could import a low sulfur subbituminous coal from the Powder River Basin. Illinois coal-fired electric generators currently import significant amounts of these coals from Wyoming and Montana to meet SO_2 limits.[237] These coals contain very low amounts of sulfur, from 0.5% to 1%. CCG could also use a low sulfur coal from the Illinois Basin. Coals are currently mined from northern and east-central Illinois that contain 1.3% sulfur.[238] If lower sulfur coals were used, the SO_2 emissions would decline from 697 ton/yr to 93 ton/yr if low sulfur PRB coal were used and to 242 ton/yr[239] if low sulfur Illinois coal were used. The decline in SO_2 emissions would be larger if the application's emissions were based on the nominal 4.22% sulfur.

Second, in the Project Summary, page 24, the IEPA argues that once a plant has been designed for a specific feedstock, a different feedstock would require the entire gasification block to be redesigned. While some coals may require redesign of portions of the coal handling system or parallel processing trains, there are many similar coals that contain lesser amounts of sulfur than the coal proposed for the TEC. *See*, for example, the USGS report[240] and Wood Mackenzie Study.[241]

The CCPSL with which the TEC is being designed to comply and is fundamental to the business purpose of the plant, requires all coal used as a feedstock to have a sulfur content of at least 1.7 lbs/mmBtu (see definition of "Clean Coal Facility": …All coal used by a clean coal facility shall have high volatile bituminous rank and greater than 1.7 pounds of sulfur per million btu content….). This requirement aside, even if one assumes it could be read to allow an average sulfur content (over a particular averaging time), the gasification block would be designed for bituminous, high-sulfur coal from the Illinois Basin. The syngas cleanup systems are capable of removing virtually all of the sulfur in the end-product SNG so that gasifying a lower-sulfur coal

[237] Wood Mackenzie Study, (Commenter's Exhibit 19).
[238] Wood Mackenzie Study, *Quality of Coal in Subdivisions 2 and 4 (Northern and East-Central Illinois)*, (Commenter's Exhibit 60)
[239] SO_2 emissions assuming 0.5% S coal: (697 t/y)(0.5%/3.75%) = 92.9 t/y. If 4.22% were used as the base: (697 t/y)(0.5%/4.22%) = 82.6 t/r. SO_2 emissions assuming 1.3% S coal: (697 t/y)(1.3%/3.75%) = 241.6 t/y. If 4.22% were used as the base: (697 t/y)(1.3%/4.22%) = 214.7 t/y.
[240] R.H. Affolter and J.R. Hatch, Characterization of the Quality of Coals from the Illinois Basin, Chapter E of: Resource Assessment of the Springfield, Herrin, Danville, and Baker Coals in the Illinois Basin, U.S. Geological Survey Professional Paper 1625-D, p. E-31, Table *5;* http://pubs.usgs.gov/pp/p1625d/508/Chapter E 508.pdf, (Commenter's Exhibit 50).
[241] Wood Mackenzie Study, p. 9.

would not result in, if any, material SO_2 reductions during normal, steady-state operation.

As the comment points out, the syngas cleanup systems will not be fully efficient during portions of startup and shutdown events when the majority of SO_2 would be emitted. However, starting up and shutting down the gasifiers on a low-Btu, low-sulfur coal such as PRB, which also differs from Illinois Basin coal in other respects, as the comment suggests would not be feasible given that the gasifiers would be designed to accept a quite different coal.

With regard to lower-sulfur Illinois Basin coal, the sulfur content used by CCG in its emissions calculations was a maximum value. As such, the typical sulfur content will be less. The comment states "Coals are currently mined from northern and east-central Illinois that contain 1.3% sulfur," referencing a Wood Mackenzie study, "Quality of Coal in Subdivisions 2 and 4 (Northern and East-Central Illinois)," (Commenter's Exhibit 60).[242] This report provides no information on whether coal is currently being mined in those regions. In fact, Exhibit 16 referenced in the comment, the Wood Mackenzie study, entitled "Location of Existing and Planned Illinois Mines, Projects and Reserves", shows only two mines located in those two regions, one is in the *Permitting* stage (#46) and one is shown as being in the *Reserve* stage (#81). Further, Appendix D ("Illinois Mines, Developments, Projects and Key Reserves") presents various coal quality data for the mines in Commenter's Exhibit 16. The sulfur content of "Mine 81" is shown as 3.2% while that of "Mine 46" (not yet permitted) is 1.3%.

Finally, the Wood Mackenzie study states, on page 24, "Most of the coal produced in Illinois will continue to contain a high sulfur content. Note in Exhibit 17 that more high sulfur coal is mined over time and this coincides with increases, especially in the eastern U.S., in use of "sulfur handling facilities" or scrubbers. By the end of the forecast period there is very little low and medium sulfur coal produced in Illinois."

In summary, given the requirements of the CCPL, gasifier design, amount of coal gasified during startup and shutdown events, and range of sulfur content of reasonably available coals, the claims made in this comment are not credible.

BACT WAS NOT REQUIRED FOR REDUCED SULFUR COMPOUNDS

55. The pollutants regulated under PSD include hydrogen sulfide ("H_2S"), "total reduced sulfur (including H_2S)" ("TRS"), and "reduced sulfur compounds (including H_2S)" ("RS"). The application (Volume. 1, Table 4-1, p.4-6) and Project Summary indicate potential emissions of TRS, RSC, and H_2S are all 8.8 ton/yr. This is under the PSD significance thresholds of 10 ton/yr for these pollutants. Thus, the application and Project Summary conclude that PSD review is not triggered for these pollutants.

The majority of these emissions originate from flaring, the SRU thermal oxidizer, equipment leaks, and the CO_2 vent. There are technically feasible and cost-effective BACT controls for

[242] **Wood Mackenzie, Delivered Price of Coal to the Taylorville Energy Center, Exhibit 6 to the Taylorville Energy Center Facility Cost Report, October 2009, available at http://www.icc.illinois.gov/electricity/tenaska.aspx**

these three pollutants from these sources, including leakless components, a more comprehensive LDAR program, the use of low sulfur coal during startup and shutdown events, the use of more efficient acid gas controls, and the use of a more efficient flare.

The application uses two arguments to avoid requiring BACT for TRS and RSC. First, it redefines the pollutant to exclude sulfur compounds that it claims are otherwise regulated as HAPs. Second, it argues that emissions of these pollutants (in each case comprising only H_2S) are under the PSD significance threshold of 10 ton/yr and thus not subject to BACT. Finally, the application concatenates TRS and RSC, treating them identically as though they were a single pollutant. Each of these issues is discussed in my comments.

These comments do not show that TRS and RSC were inappropriately addressed by the application and would therefore be improperly approached by the permit. The comments fail to recognize the implications of high-temperature gasification technology, which would be used at the TEC, for the composition of the raw syngas and converts sulfur to inorganic sulfur compounds, like H_2S, rather than organic sulfur compounds. The comment also overlooks the implications of the relevant law and rule on the scope of pollutant TRS, as regulated under the PSD program.

56. The Draft Permit would improperly redefine the PSD pollutants. The PSD rules do not define the terms "total reduced sulfur (including H_2S)" (TRS) and "reduced sulfur compounds (including H_2S)" (RSC). The application argues that TRS and RSC consist of the sum of H_2S, COS, and carbon disulfide ("CS_2"), citing a definition from NSPS Subpart J, 40 CFR 60.101 for petroleum refineries, promulgated prior to the original August 1980 PSD rules. The application next asserts that as COS and CS_2 are HAPs regulated under Section 112 of the Clean Air Act, they cannot be simultaneously regulated under the PSD program.[243]

Why would USEPA designate two separate pollutants for reduced sulfur compounds that contained exactly the same three compounds? The fact that they exist as separate PSD pollutants indicates that this interpretation is wrong. Material in the docket of the original 1980 PSD rulemaking indicates that at the time that the PSD rules were adopted, the USEPA considered TRS to consist of H_2S and methyl mercaptan, dimethyl sulfide, and dimethyl disulfide or simply H_2S plus reduced organic sulfur compounds. RSC consisted of H_2S, carbon disulfide and carbonyl sulfide or simply inorganic reduced sulfur compounds.[244] Thus, RSC and TRS are two separate pollutants, containing different reduced sulfur compounds, and having only H_2S in common. There is no basis for assuming that TRS and RSC consist of exactly the same three compounds based on a definition from 40 CFR 60.101 for refineries.[245] The application erred by assuming these were the same pollutant and replacing them with only H_2S.

[243] Ap., v. 1, p 3-2, Table 3-1, notes 4 and *5* and p. 4-4.
[244] USEPA, Impact of Proposed and Alternative *De Minimis* Levels for Criteria Pollutants, Report EPA-450/2-80-072, June 1980, Tables 1 and 2, cited at *45* FR 52706 (Aug. 7, 1980).
[245] Definitions in other sections of 40 CFR, as follow, confirm that RSC and TRS are separate pollutants.
"Reduced sulfur compounds" is defined at 40 CFR 60.641, Definitions: "Reduced sulfur compounds means H_2S, carbonyl sulfide (COS), and carbon disulfide (CS_2)."
"Total reduced sulfur" is defined at 40 CFR 60.281, Definitions: "Total reduced sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide, that are released during the kraft pulping operation and measured by Method 16."

This comment grossly misrepresents the approach to TRS and RSC in the application. As shown in Table 3-1 of the application, TRS and RSC are clearly addressed as separate and distinct pollutants, with references to the relevant regulatory definitions in the NSPS that define these pollutants, i.e., for TRS, 40 CFR 60.281, and for RSC, 40 CFR 60.101 (which is identical to 40 CFR 60.641).[246] In addition, the comment overlooks 40 CFR 52.21(b)(50)(v), which provides that regulated NSR pollutants shall not include HAPs listed under Section 112 of the Clean Air Act.

57. There is no legal or technical basis to piecemeal a regulated pollutant, such as TRS and RSC, stripping them into parts and treating each differently. TRS and RSC are both listed as PSD pollutants as groups, primarily to avoid nuisance (odor) problems,[247] not as a collection of individual compounds to prevent health effects. Thus, there is no basis for pulling apart the group and arguing that part of it is regulated elsewhere due to health impacts. In this sense, TRS and RSC are no different than VOCs, which are regulated as ozone precursors under the NSR program while select members of the VOC group are also regulated as HAPs. In applying NSR, one does not subtract VOC HAPs from ozone- precursor VOCs, as different aspects of the compounds are being regulated under each rule.

Further, pulling apart reduced sulfur groupings makes no sense as individual members of each of these groups interact, resulting in more significant impacts together than one at a time. Regardless, even assuming a regulated pollutant such as total reduced sulfur could be piecemealed based on duplicate regulation; in this case, these compounds in fact are not regulated under MACT as the CCG claims the TEC is a minor source not subject to MACT.

The treatment of TRS and RSC in the application is consistent with applicable regulatory definitions given the specific way that each of these pollutants has been defined by USEPA. TRS is identified as H_2S, methyl mercaptan, dimethyl sulfide and dimethyl disulfide, while RSC is H_2S, COS, and carbon disulfide. The presence of the individual constituents in emissions was appropriately considered in determining the potential emissions of RSC and TRS from the TEC for comparison to the PSD significance emission rates.

58. Emissions of Reduced Sulfur Compounds (RSC) exceed the significant emission rate. The significant emission rate for RSC under the PSD rules is 10 tons/year (40 CFR 52.21(b)(23)(i)). As discussed in other comments, RSC consist of the sum of inorganic reduced sulfur compounds, including carbonyl sulfide and carbon disulfide.

The emission data in the application indicate that total facility-wide potential emissions of RSC are12.9 tons/yr (H_2S - 8.78 tons/yr, COS - 4.ll tons/yr, and CS_2 - 0.00894 tons/yr). This triggers applicability of PSD for RSC. CCG apparently crafted the piecemeal argument, removing COS and CS_2 from the pollutant RSC, to avoid triggering PSD for RSC. Further, the data in the application underestimates emissions of RSC, due to errors in the emission data for some of the contributing sources, as discussed in my other comments.

[246] **See Application Vol. 1 at 3-2, Table 3-1, Notes 4 and 5.**
[247] 45 FR 52676 at 52709 (Aug. 7, 1980) ("Total Reduced Sulfur, Reduced Sulfur — These pollutant classes include hydrogen sulfide (H_2S) and are regulated primarily to avoid nuisance (odor) problems").

While RSC is a PSD pollutant, pursuant to the CAA (Section 112(b)(6)) listed HAPs, such as COS and carbon disulfide, CS_2, are not subject to PSD requirements. USEPA's definition of regulated NSR pollutant in 40 CFR 52.21(b)(50) also supports that COS and CS_2 are not considered under PSD. Only HAPs that are also regulated as a constituent or precursor of a pollutant listed under CAA § 108 (i.e., criteria pollutants) are considered regulated NSR pollutants. Neither COS nor CS_2 are regulated by USEPA as a constituent or precursor of a criteria pollutant and therefore are not subject to PSD even as RSC. To conclude otherwise would contravene the express will of Congress in the CAA, which post dates USEPA's regulation of RSC. The only non-HAP RSC emitted by TEC will be H_2S. As emissions of H_2S and therefore RSC are less than 10 tons per year, PSD requirements, including BACT, are not triggered for RSC.

59. The emissions of Total Reduced Sulfur (TRS) are also significant. The significant emission rate for TRS under the PSD rules is 10 ton/yr. TRS consists of the sum of emissions of H_2S plus emissions of reduced organic sulfur compounds, i.e., dimethyl sulfide and dimethyl disulfide. The application did not include data for any reduced organic sulfur compounds that would be present in TEC's emissions.

Gasification facilities emit reduced organo-sulfur compounds, including mercaptans and dimethyl sulfide,[248] which are not HAPs and thus cannot be dismissed even under CCG's erroneous argument. Thus, emissions of these compounds should have been included in the emission inventory. Correcting just the errors in the equipment leak emissions, emissions of total reduced sulfur compounds exceed 10 ton/yr because H_2S is explicitly included in this pollutant and its emissions increase from 8.78 ton/yr reported in the application to 13.9 ton/yr when USEPA's refinery emission factors are used to estimate equipment leaks. Thus, PSD is applicable for TRS. This review must include an estimate of emissions of all compounds included in this pollutant.

Similar to the above response, the only TRS compound emitted by TEC is H_2S. Therefore, the plant-wide TRS annual potential emission rate listed in Table 3-2 of the application is equivalent to the H_2S annual potential emission rate and was correctly relied upon to demonstrate the TEC does not trigger PSD review for TRS.

BACT WAS NOT REQUIRED FOR CO_2 EMISSIONS FROM THE AGR VENT

60. The gasification block would convert coal into synthesis gas or "syngas." This syngas would then be processed to remove contaminants and prepare it for conversion into substitute natural gas (SNG), which would then either used as fuel to generate electricity or sold to others. The contaminants removed from the raw gas include particulate, mercury, sulfur compounds and CO_2. The CO_2, if not sequestered, would be emitted to the atmosphere from the AGR vent. This is the principal source of greenhouse gas (GHG) emissions from the TEC. The application does not require any control for CO_2 emissions from the AGR vent and thus fails to satisfy BACT. This is because the IEPA did not properly evaluate carbon capture and sequestration ("CCS") as part of the BACT analysis

[248] Tim Lieuwen, Vigor Yang, and Richard Yetter (Eds.), Synthesis Gas Combustion. Fundamentals and Applications, 2010, Sec. 6.3 and Christopher Higman and Maarten van der Burgt, Gasification, 2nd Ed., Elsevier, 2008, Table 6.2.

and improperly eliminated it as BACT for CO_2. Although CCS receives cursory discussion as part of top-down BACT, it is promptly eliminated as infeasible for a host of vague, unsupported, and, upon more thorough review, wrong reasons. This is particularly serious for this project, which presents one of the better and more cost-effective opportunities in the nation to implement this technology.

Since CCS technology is clearly available, is planned at other IGCC sources, and has been determined to be feasible using nearby sequestration opportunities by CCG's *own analysis* (at an earlier time when political opportunities favored such a conclusion), IEPA was required to fully evaluate technical feasibility under Step 2. Had it done so, it would have properly concluded that CCS is, in fact, technically feasible for the Project, and would have been required to proceed to Step 4 to evaluate cost-effectiveness. When CCS is fairly evaluated, it becomes clear that it is both feasible and cost-effective for the CCG project and, therefore, must be required as BACT.

For the CO_2 vent of the AGR Unit, the IEPA Improperly Eliminated CCS as Technically Infeasible in BACT Step 2. As explained in the Project Summary, this unit would be one of the plant's principal sources of CO_2 emissions, with the potential to emit 2,500,000 tpy. While IEPA and CCG accept CCS as "available" for purposes of BACT Step 1 (as they must, pursuant to USEPA's PSD and Permitting Guidance for Greenhouse Gases[249] ("GHG BACT Guidance")), they reject it under Step 2 based on "technical infeasibility." *See* Project Summary at 29-33.[250] In addition to a number of inchoate references to general legal and financial concerns that do not constitute BACT Step 2 factors, IEPA relies on two primary technical concerns: (a) the unavailability of a CO_2 pipeline for EOR purposes, and (b) "many other technical issues associated with geologic CO_2 sequestration [in the Mt. Simon formation that] still need to be resolved." However, as explained below, available information, including CCG's own statements in other contexts, clearly demonstrates that CCS is technically feasible, in contrast to the cursory and conclusory statements made by CCG and IEPA.

The IEPA Failed to Conduct a Proper BACT Step 2 Analysis to Support its Conclusion that CCS Is Infeasible. The NSR Manual and opinions regarding top-down BACT by the EAB interpret BACT as requiring considerable specificity in a Step 2 feasibility evaluation. The NSR Manual requires that in Step 2, "A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review." NSR Manual, B-6. The NSR Manual describes Step 2 as a two-part analysis of both whether the technology at issue is commercially available on any source, and whether, if so, it is applicable to the source type at issue:

> Two key concepts are important in determining whether an undemonstrated technology is feasible: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if it can be obtained by the

[249] *Available at http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf*. (Commenter's Exhibit 51) The GHG BACT Guidance states at 32, "For the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is 'available," and that "CCS should be listed in Step 1 of a top-down BACT analysis for GHGs."

[250] While IEPA does not walk through the steps in a top-down BACT analysis, its elimination of CCS as technically infeasible is consistent with a decision under BACT Step 2.

> applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.
> NSR Manual, page B- 17.

The NSR Manual further specifies that a technology is presumed to be applicable where it is "soon to be deployed" at a similar source type; but that even if it is not, the permitting authority must still make its own reasoned technical judgment as to applicability:[251]

> Technical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (*e.g.,* is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously.
> NSR Manual, page B-17.

The GHG BACT Guidance does allow for the possibility that, in the circumstances where there are "significant and overwhelming technical (including logistical) issues associated with the application of CCS for the type of source under review (*e.g.,* sources that emit CO_2 in amounts just over the relevant GHG thresholds and produce a low purity CO_2 stream) a much less detailed justification may be appropriate and acceptable for the source." GHG BACT Guidance at 36. However, this Guidance makes clear that the applicability of this exception to the generally stringent analytical requirements of Step 2 is specifically limited to situations where sequestration opportunities are generally unavailable, *and* where CCS has never been used in the same source category:

> In circumstances where CO_2 transportation and sequestration opportunities already exist in the area where the source is, or will be, located, or in circumstances where other sources in the same source category have applied CCS in practice, the project would clearly warrant a comprehensive consideration of CCS. In these cases, a fairly detailed case-specific analysis would likely be needed to dismiss CCS.
> GHG BACT Guidance, page 36

[251] The EAB also addressed this topic in *In re Mississippi Lime.* The EAB rejected IEPA's Step 2 analysis as deficient, holding that IEPA had not sufficiently evaluated the feasibility of natural gas firing in the subject lime kiln. The decision noted, in particular, that reliance upon a natural gas pipeline cost estimate was not sufficient basis to eliminate the natural gas option under Step 2, but rather required that IEPA proceed to Step 4 in order to evaluate cost effectiveness. "IEPA's attempts to frame the use of natural gas as an "unresolvable technical difficulty" based on the proposed plant site's distance from the existing natural gas pipeline fail to recognize that "where the resolution of technical difficulties is a matter of cost, the applicant should consider the technology as technically feasible." NSR Manual at B. 19. Because IEPA's "technical" difficulty is actually merely a matter of cost, IEPA has not shown that natural gas is technically infeasible... On this record, IEPA's consideration of natural gas as BACT should have included a Step 4 BACT analysis. Instead, the entirety of IEPA's analysis prior to determining natural gas "not commercially feasible" was a single cost estimate for extending natural gas service to the proposed plant. Mississippi Lime Additional Information at 18. This cost estimate failed to consider the average and incremental cost-effectiveness of natural gas." *In re Mississippi Lime,* slip op. at 7.

In this regard, the "logistical hurdles" referenced in connection with this limited exception should not be read to generally conflate issues of cost properly considered under Step 4 with those of technical feasibility that are relevant to Step 2. USEPA properly points out that for CCS, "as with all top-down BACT analyses, cost considerations should not be included in Step 2 of the analysis, but can be considered in Step 4." GHG BACT Guidance, page 37. The GHG BACT Guidance suggests that logistical factors relevant to a Step 2 analysis of CCS "may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long term storage." GHG BACT Guidance, page 36. But those factors could be relevant to Step 2 only to the extent that they make CCS technically infeasible. If, instead, these logistical factors would merely require the spending of additional resources to resolve, then those factors should be deferred to Step 4 because, as was explained in the NSR Manual:

> Where the resolution of technical difficulties is a matter of cost, the applicant should consider the technology as technically feasible. The economic feasibility of a control alternative is reviewed in the economic impacts portion of the BACT selection process.
>
> A demonstration of technical infeasibility is based on a technical assessment considering physical, chemical and engineering principles and/or empirical data showing that the technology would not work on the emissions unit under review, or that unresolvable technical difficulties would preclude the successful deployment of the technique. Physical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility. However, the cost of such modifications can be considered in estimating cost and economic impacts which, in turn, may form the basis for eliminating a control technology
> NSR Manual, pages B. 19 and B.20)

To the extent that these logistical hurdles may be considered at all in a Step 2 analysis at all, it is clear that they are intended only to apply to "smaller sources" — for example, "a small natural gas package boiler" that may not have the "resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations." *Id.* Clearly, the proposed plant, with a multi-billion dollar cost,[252] is not a "smaller" source.

Notwithstanding these clear requirements, IEPA presented no "detailed case specific analysis" of the technical feasibility of CCS in Step 2. As discussed in more detail below, it confined its evaluation to vague and largely unsupported references to purported technical and general non-technical hurdles to implementation. These generalized issues clearly do not constitute the detailed case-by-case technical evaluation of feasibility contemplated in Step 2, which requires for a showing of infeasibility a demonstration "based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review."[253] It is not sufficient for IEPA to simply regurgitate results of a broad general analysis of largely non-

[252] Capital cost set forth in Facility Cost Report at 23.
[253] NSR Manual at B.6.

technical barriers to implementation of CCS in the United States as a basis to circumvent the requirement that it conduct detailed analysis and produce a well-reasoned and supported project-specific determination.

This comment maintains that the BACT evaluation improperly eliminated CCS as a control option for CO2 emissions from the AGR vent. The basis for this conclusion apparently rests with the belief that CCS is "clearly available" and, because it is being "planned at other IGCC projects," it should have been more fully considered at Step 2 of the Top-Down BACT Process and deemed technically feasible.

The legal framework for this discussion is the same that was identified earlier in response to comments relating to the nature of the BACT evaluation. Step 1 of the Top-Down BACT Process identifies all potentially available control technologies, whereas Step 2 considers the actual, rather than potential, technical feasibility of such control technologies. As previously mentioned, a control option is considered "demonstrated" if it has been installed and operated successfully on the source type being reviewed. *See, Minnkota Power Coop. at 5 (citing NSR Manual at B.17).* A permit authority may determine that a particular control option is not adequately demonstrated where the proposed source is a new and dissimilar source type category compared to other sources that have successfully employed a given control option. *Id. at 19-20* (observing that BACT is a "case-by-case analysis specifically designed to avoid generalizations; namely, that SCR [or any given control option] applied anywhere in the country at a coal-fired boiler with the same rated capacity [as Minnkota Power's] is the same 'type of source'")

In the absence of a technology that is demonstrated in practice, the Step 2 analysis must evaluate whether the control option is "available" and "applicable" to the proposed source. As USEPA's recent guidance makes clear, a technology is "available" if it can be obtained commercially or can otherwise be secured in the ordinary sense of the term. *See, PSD and Title V Permitting Guidance for GHG* at page 34; see also, *In re Cardinal FG Company*, 12 EAD at 166; *NSR Manual* at B.18 (recognizing that a "control technique is considered available . . . if it has reached the licensing and commercial sales stage of development"). Control options that pose "questionable or dubious reliability" are not considered "available" under BACT. *See, Cardinal FG Company* at 166. Instead, an evaluation of BACT "must be solidly grounded on what is *presently known* about the selected technology's effectiveness." *Newmont Nev. Energy Investment, LLC*, at 441. The need for further pilot testing and resulting delays may serve as a reasonable basis to conclude that a given control option is not "available." *See, Minnkota Power Coop* at 22-26. As previously discussed, BACT does not compel a permit applicant or permitting authority to speculate as to the effectiveness of an undemonstrated technology or accept the risks that an unproven control option will not prove workable at the proposed source.

A control option is "applicable" under Step 2 if it can reasonably be installed and operated on the source type being reviewed. Where a control technology has already been applied to a source type, the issue "is largely a question of the transferability of the technology to another source type." *See, PSD and Title V Permitting Guidance for*

GHGs at 34. **As USEPA explains in its guidance, "[t]he control technology would not be applicable if it can be shown that there are significant differences that preclude the successful operation of the control device."** ***Id.; see also, Minnkota Power Coop.*** **at 27 (affirming permit authority's decision regarding technical infeasibility based on finding that characteristics at the proposed source were "significantly different from other sources that have applied [control option] and these unique characteristics present significant challenges to [its] successful application . . . ").**

USEPA has stated that this consideration should explore "all characteristics" of a control option to determine whether there is evidence to show that the technology is not technically feasible. ***See, PSD and Title V Permitting Guidance for GHGs at 34.*** **The applicant is responsible for providing evidence that an available control measure is technically infeasible.** ***Id.*** **The permitting authority is then ultimately responsible for deciding technical feasibility based on this evidence.** ***Id.***

In this instance, the information provided by CCG in the Application,[254] as well as the IEPA's independent analysis as reflected in the Project Summary, supports the conclusion that at this time CCS is not technically feasible for the control of CO_2 emissions from the plant's AGR Unit Vent. This conclusion generally rests on the premise that CCS technologies are not yet developed as to warrant recognition that they are available and applicable to the plant at this time. This determination regarding the technical infeasibility of CCS is fully consistent with the legal framework for Step 2 of the BACT analysis discussed above and, further, is in accord with the USEPA's recent guidance addressing specific considerations for CCS technologies.

Notably, in its GHG BACT Guidance, USEPA explicitly recognizes that, at present, CCS would likely be eliminated as BACT due to technical infeasibility. ***See*** **GHG BACT Guidance, page 36 ("While CCS is a promising technology, USEPA does not believe that at this time CCS will be a technically feasible BACT option in certain cases."). According to USEPA, CCS would properly be excluded from a BACT analysis in Step 2 where the record shows that site-specific factors related to the three main components of CCS (capture and compression, transport, and storage) differ significantly from what has already been applied to another source.** ***Id.*** **at 35. As USEPA goes on to explain:**

> **CCS may be eliminated from a BACT analysis in Step 2 if the three components working together are deemed technically infeasible for the proposed source, taking into account the integration of the CCS components with the base facility and** ***site-specific considerations (e.g., space for CO_2 capture equipment at an existing facility, right-of-ways to build a pipeline or access to an existing pipeline, access to suitable geologic reservoirs for sequestration, or other storage options).*** **GHG BACT Guidance, page 36 (emphasis added).**

---

[254] **In the permit application, CCG combined Step 1 and Step 2 in its CO_2 BACT analysis for the AGR. Although it is labeled as "Step 1" by CCG, the CCS control option is clearly eliminated as BACT for the AGR's CO2 emissions on the basis of technical feasibility under Step 2 and not on the basis of the potential availability under Step 1.** ***See,*** **Application at 6-3 through 6-9. The permit applicant's approach at merging Steps 1 and 2 in this fashion is not of consequence, as the rationale for the treatment of the issue is plainly manifest from the document.**

In this guidance USEPA recognized the distinction between controls for criteria pollutants, which typically are located at the source and CCS, which requires offsite assets typically under control of third parties if they exist at all. Further acknowledging certain practical necessities for CCS to be deemed feasible in Step 2, USEPA stated:

> **EPA recognizes the significant logistical hurdles that the installation and operation of a CCS system presents and that sets it apart from other add-on controls that are typically used to reduce emissions of other regulated pollutants and already have an existing reasonably accessible infrastructure in place to address waste disposal and other offsite needs. *Logistical hurdles for CCS may include obtaining contracts for offsite land acquisition (including the availability of land), the need for funding (including, for example, government subsidies), timing of available transportation infrastructure, and developing a site for secure long term storage*. Not every source has the resources to overcome the offsite logistical barriers necessary to apply CCS technology to its operations, and smaller sources will likely be more constrained in this regard. *Based on these considerations, a permitting authority may conclude that CCS is not applicable to a particular source, and consequently not technically feasible, even if the type of equipment needed to accomplish the compression, capture, and storage of GHGs are determined to be* generally available from commercial vendors.**
> **GHG BACT Guidance, page 36 (emphasis added).**[255]

In the case of the TEC, while control of CO_2 through CCS may be theoretically feasible, the very same logistical hurdles noted by USEPA in its GHG BACT Guidance make this control option technically infeasible *for the purposes of BACT*. As the Project Summary discusses, considerable uncertainty exists with respect to a number of requisite conditions for CCS here, including access to an existing pipeline and a suitable geologic reservoir over the life of the plant, sequestration field land and subsurface rights acquisition, development of a site for secure long-term storage, proven geology favorable for long-term storage, and other uncertainties about the long-term ability of the Mt. Simon formation to sequester CO_2. *See* Project Summary at 29-32. Importantly, these critical factors are specialized (if not unique) and largely outside of CCG's ownership and control. Moreover, unlike a piece of typical control equipment, the characteristics of an underground geological formation cannot be duplicated or modified. As such, these are not the sort of logistical hurdles that can be resolved simply by the spending of additional resources. There is no way in fact to ensure that these hurdles can be overcome before the TEC would commence operation. Requiring CCS as BACT under these circumstances would improperly subject CCG to considerable risk of unavoidable noncompliance. *See In re Kendall New Century Dev.*, 11 E.A.D. 40, 53 (EAB 2003) ("We have held that permit writers retain discretion to set BACT levels that 'do not necessarily reflect the highest possible control efficiencies but, rather, will allow permittees to achieve compliance on a consistent basis.'") (quoting *In*

[255] **The NSR Manual also notes that "a showing of unresolvable technical difficulty with applying the control would constitute a showing of technical infeasibility (e.g., size of the unit, location of the proposed site, and operating problems related to specific circumstances of the source)." NSR Manual, page B.19.**

***re Steel Dynamics, Inc.*, 9 E.A.D. 165, 188 (EAB 2000)) (footnote omitted); *accord In re Three Mountain Power, LLC*, 10 E.A.D. 39, 53 (EAB 2001); *In re Masonite Corp.*, 5 E.A.D. 551, 560-61 (EAB 1994); *see also In re Knauf Fiber Glass, GmbH*, 9 E.A.D. 1, 15 (EAB 2000) ("There is nothing inherently wrong with setting an emissions limitation that takes into account a reasonable safety factor. * * * The inclusion of a reasonable safety factor in the emission limitation calculation is a legitimate method of deriving a specific emission limitation that may not be exceeded.").**

The fact that CCS has been used at another coal gasification plant (Dakota Gasification's Great Plains Synfuels Plant) and proposed at four others (Summit Texas Clean Energy, Southern Company, Hydrogen Energy California, and Indiana Gasification) does not establish CCS as BACT for CO_2 at the TEC given the logistical hurdles specifically at issue for the TEC. Most notably, as compared to the Great Plains Synfuels Plant, the same circumstances for CCS (i.e., nearby oil fields suitable for EOR) does not currently exist within a reasonable distance of the planned site of the TEC.[256] More generally, CO_2 sequestration (i.e., a proven storage site suitable and available for the CO_2 emissions of the TEC) also does not currently exist near the site. This is explained in the application and Project Summary. *See* Application at 6-6; Project Summary at 32-33. BACT cannot proceed simply based on speculation regarding future access to these facilities necessary for successful CCS operation. Accordingly, CCS is not technically feasible as a BACT-level CO_2 control for the TEC.

61. The analysis of geologic sequestration in the Mt. Simon sandstone formation was flawed. For geologic sequestration in this formation, IEPA's cursory "analysis" of Step 2 technical infeasibility acknowledges a "detailed feasibility study" done by CCG's own consultant that had "favorable" results, but then vaguely relies on "many other technical issues associated with geologic CO_2 sequestration [that j still need to be resolved" and "unresolved issues involving the regulatory requirements for sequestration and liability associated with sequestration" to reject CCS. *See* Project Summary at 32. This discussion is wholly inadequate in terms of meeting the agency's evidentiary burden, as well as wrong as a matter of technical substance.

In February 2010, in connection with the now-defunct Illinois Clean Coal Portfolio Standard Law, under which CCG was required to show that the TEC would use CCS in order to qualify as the "initial clean coal facility" in Illinois, Tenaska submitted a Facility Cost Report (Facility Cost Report)[257] for the TEC to the Illinois Commerce Commission, Illinois Power Agency, and Illinois General Assembly. In the Facility Cost Report, pages 80 and 81, Tenaska explained CCG's strategy of pursuing the sale of its CO_2 for EOR through its contract with Denbury while also developing its own sequestration facility near the TEC. On page 77, the Facility Cost Report further noted that CCG "has developed a backup geologic storage strategy that it *will implement* if the Denbury pipeline is not completed in a timely

[256] The Great Plains Synfuels Plant is situated close to two major oil fields in Saskatchewan, Canada (the Weyburn and Midale fields). As a consequence of the proximity of these fields and their relatively small, concentrated area (about 80 and 40 square miles, respectively), the output of CO_2 from that plant is expected to be able to productively and economically used as a resource for enhanced oil recovery (EOR) in those oil fields for the next 20 to 25 years. (Refer to http:/en.wikipedia.org/Weyburn-Midale_Carbon_Dioxide_Project.)

[257] Worley Parsons, Taylorville Energy Center — Facility Cost Report (Feb. 26, 2010), available at http://www.icc.illinois.gov/electricity/tenaska.aspx. (Commenter's Exhibit 52)

manner." Having made clear in the context of that legislation that it plans to sequester CO_2, CCG cannot now cursorily dismiss CCS as somehow not technically feasible.

The Facility Cost Report included two supporting reports prepared by Schlumberger Carbon Services ("Schlumberger"), a Feasibility Study and a Cost Study, evaluating in significant detail the possibility of sequestration of captured CO_2 in the Mt. Simon sandstone formation that underlies Central Illinois.[258] That analysis considered all of the appropriate technical feasibility issues such as geologic suitability of the Mt. Simon site, injection well plume modeling, seismic data, etc. The Feasibility Study found that use of the site was entirely feasible for the TEC:

> A geological study was completed to develop an assessment of the suitability of the site for storage of carbon dioxide. The work is the first phase in developing a geologic carbon dioxide (CO_2) storage site in the Mt. Simon formation. The goal of the study was to evaluate:
>
> 1. Whether the site has capacity to store the expected volume of CO_2 from the plant;
> 2. Containment of the storage reservoir;
> 3. Infrastructure requirements for storage (number and dimensions of injection wells, operational strategies)
>
> The results of the study indicate that the Mt. Simon sandstone has sufficient porosity (open space between the sand grains in the rock) and permeability (the degree to which the pore spaces are interconnected, allowing fluid to move through the rocks) and therefore provides a storage reservoir target capable of accommodating all of the CO_2 produced by the plant over a planned operational life of 30 years. The Eau Claire formation, which overlies the Mt. Simon sandstone, will provide the vertical containment needed to prevent movement of CO_2 out of the Mt. Simon formation and into shallower geologic formations, ground water, and the atmosphere. There are also several other low permeability layers that provide secondary containment. The Mt. Simon formation and the containment layers are laterally extensive and available information, including the results of a subsurface (seismic) survey, confirm that there are no faults or breaks in the lateral continuity.
> Schlumberger Feasibility Study, page 1.

The Schlumberger Cost Study further observes that:

> The geologic setting is favorable. The target formation of the Mt. Simon is estimated to be very thick at 1100-1300 feet with a high estimated porosity and permeability in the area selected. The thickness combined with the porosity and permeability allows for a high capacity injection field to be developed using a minimal number of wells. The field is estimated to only require 3 to 4 wells with a well spacing of only 2 miles. The thickness also reduces the area required for the

[258] See Schlumberger Carbon Services Summary Results for Carbon Storage Feasibility Study "Schlumberger Feasibility Study," Facility Cost Report, Exhibit 13.2.a, (Commenter's Exhibit 53) and Schlumberger Carbon Services Cost Report for the Taylorville Energy Center ("Schlumberger Cost Study," Facility Cost Report, Exhibit 13.2.b (Commenter's Exhibit 54), cited at Project Summary, page 3l, note 29.

> CO_2 resulting in reduced right of way. Also, the target area is under and adjacent to the plant resulting in minimal pipeline cost.
> Schlumberger Cost Study, page 1.

None of this specific technical information was considered in the rejection of CCS as technically infeasible.

The Project Summary also failed to take into consideration both existing CCS projects, including one in the vicinity of the site of the TEC, demonstrating that the technology is technically available, and planned projects specifically employing CCS in the IGCC context to demonstrate applicability. The Project Summary makes essentially no mention of the CCS project at Archer Daniels Midland ("ADM") in Decatur, Illinois, 30 miles from the proposed TEC site, to sequester CO_2 from an ethanol manufacturing facility in the Mt. Simon formation.[259, 260] The biggest source of technical uncertainty in any sequestration project is the suitability of the geology,[261] but that issue has already been addressed here. Not only does the Schlumberger Feasibility Study provide a clear preliminary evaluation of the geologic suitability of the site and a description of concrete steps, along with estimated costs, for establishing such suitability, but the practical experience and wealth of data that have already been obtained as part of the ADM Decatur project have filled many previous knowledge gaps and significantly decreased the complexity and cost of the remaining task for the TEC. Now that the Midwest Geological Sequestration Consortium ("MGSC") - with the help of ADM, Schlumberger and US DOE - has performed the characterization, IEPA should have used that knowledge in its analysis of technical feasibility (and, as discussed in other comments concerning Step 4, CCG could have used it to curtail its site characterization expenses). A good deal of operational knowledge is gained when a well is drilled in a new formation, which should have been considered in the BACT analysis for CCG. In the face of this wealth of information supporting sequestration nearby the site, IEPA's rejection of CCS by referencing "many other technical issues" justifying rejection of CCS falls far short of meeting the obligations for a BACT analysis.

Furthermore, as to applicability (*i.e.*, whether a control option can reasonably be installed and operated on the source type under consideration), the Project Summary references but fails to evaluate three planned full-scale IGCC CCS projects being sponsored by USDOE. IEPA writes them off simply by noting that the Facility is not one of these projects. This cursory dismissal is unacceptable for purposes of Step 2 analysis. IEPA should be required, at minimum, to explain why, if at all, the proposed CCG project differs from the DOE projects so as to make CCS technically infeasible for CCG, given that USDOE has determined it to be fully feasible elsewhere (particularly in light of the availability of the nearby Mt. Simon formation). See NSR Manual at B.17.[262]

---

[259] See MIT fact sheet concerning the ADM project available at http://seguestration.mit.edu/tools/projects/decatur.html.(Commenter's Exhibit 55)
[260] See presentation by Robert J. Finley of the Midwest Geological Carbon Consortium on the Illinois Basin Decatur Project available at http://www.netl.doe.gov/publications/proceedings/1 1/carbon storage/wednesday/RFinley NETL IBDP Overview Novl6.pdf. (Commenter's Exhibit 56)
[261] See Interdisciplinary MIT Study on the Future of Coal, 2007, p. 43 et seq., available at http://web.mit.edu/coal/The Future of Coal.pdf. (Commenter's Exhibit 57)
[262] "For process-type control alternatives the decision of whether or not it is applicable to the source in question would have to be based on an assessment of the similarities and differences between the proposed source and other sources to which the process technique had been applied previously. Absent an explanation of unusual circumstances by the applicant showing why a particular process cannot be used on the proposed source the review authority may presume it is technically feasible."

Finally, IEPA erred in its reliance on Underground Injection Control ("UIC") program requirements in eliminating from consideration "carbon sequestration in the Mt. Simon formation or any other candidate geologic sequestration site," as discussed in Note 35, page 32 of the Project Summary. IEPA cryptically cites "unresolved issues involving the regulatory requirements for sequestration and liability" in one sentence, followed by a second sentence setting forth that "[f]urther development of sequestration is needed" before BACT can be set based on CCS. This second sentence is accompanied by a footnote discussing USEPA's UIC regulations for groundwater protection. The footnote asserts that the project might not be able to obtain a permit in a timely manner, or even if it could obtain a permit, it might not be possible to sequester CO_2 from the plant in the Mt. Simon formation under the UIC program. This discussion again fails to meet IEPA's administrative burdens. Because the UIC program presents no significant hurdle to CCS, it cannot be used as a justification for eliminating CCS in Step 2.

USEPA adopted its Class VI rule for underground injection of CO_2 for geologic sequestration, 40 CFR Part 146, in December, 2010. This rule provides a clear and well-defined regulatory path for a facility developer wishing to obtain a permit for CO_2 sequestration, and addresses the specific concerns identified by IEPA in the Project Summary. Specifically, as the Project Summary itself correctly describes (at p. 32, n. 35), "the 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. These requirements are tailored to address the specific characteristics of CO_2 when it [i]s sequestered, including the large volume of material, the buoyancy and viscosity of CO_2, and its chemical properties, as compared to materials previous addressed under the UIC program". The fact that the rule sets clear financial responsibility requirements that owners and operators must carry, offering a wide variety of financial instruments that can be used, and that it also sets a default post-injection monitoring period of 50 years, which can be modified if a showing is made to the UIC Program Director, is in stark contrast to the Project Summary's assertion (at p. 35) that "there are unresolved issues involving the regulatory requirements for sequestration and liability associated with sequestration".

I note, in this regard, that the GHG BACT analysis provided by CCG incorrectly states that the Class VI rule under the UIC Program has not yet been promulgated, and complains, "Without clarity on what body has the appropriate regulatory authority to grant Class VI injection well approval, it is unclear when EPA will promulgate a final Class VI rule or whether CCG will be able to obtain an injection well permit in a timely manner, and even if a permit is obtained, whether CCG will be able to permanently sequester CO_2 produced by the AGR vent in the Mt. Simon formation under the proposed permit system.[263] While IEPA corrects this statement in the Project Summary, it fails to correct and eliminate the incorrect conclusions that flow from it with respect to purported legal uncertainties surrounding CCS.

[263] Updated Prevention Of Significant Deterioration And State Construction Permit Application For The Taylorville Energy Center, Illinois Permit No. 05040027 Volume 3 Of 3 Greenhouse Gas Best Available Control Technology Analysis, at 6-9.

CCG has submitted an application for a UIC Class VI permit[264], and IEPA offers no reason or information to suggest that the permit cannot be granted. The results of CCG's 2D geologic survey, as reported in that permit application, are favorable.[265] These modeling results in that application indicate that sequestration is feasible. CCG's monitoring plan also indicates that CCG is successfully navigating the long-term management issues that IEPA vaguely argues may be insurmountable. Moreover, the Class VI permit application submitted by ADM provides additional support for concluding that sequestration in the Mt. Simon formation is feasible and a permit for it obtainable. [266] Clearly, there is no basis for a categorical assumption that permitting the needed CO_2 injection wells in the Mt. Simon formation would not be possible.

The fact that the TEC would be required to capture and sequester a certain portion of its CO_2 emissions to qualify as a "clean coal facility" and receive certain benefits under the CCPSL does not establish that sequestration is currently "technically feasible" for the plant for purposes of PSD. The CCPSL simply sets criteria for sequestration of CO_2 from the plant that, if met, would entitle CCG to certain financial benefits for the operation of the plant under state law. The option to sequester under the CCA did not reflect a determination that sequestration was technically feasible, as this term is defined in the context of BACT.

The CCPSL also would require CCG, in addition to other penalties, to make monetary payments to the State of Illinois if the applicable sequestration levels were not achieved. This monetary payments provision, which provides CCG flexibility in the event that CCS is not available when the plant begins operation or fails to achieve certain performance metrics thereafter, is in no way comparable to a strict, not-to-exceed BACT limit. As the Project Summary recognizes, CCG could have no certainty about whether or not a CO_2 BACT requirement based on the use of CCS could be complied with initially when the TEC becomes operational or consistently thereafter throughout the plant's 30 year operating life. *See* Project Summary at 31-32. Thus, while CCG may reasonably be able to commit to meeting the sequestration provisions of the CCPSL, this does not demonstrate that CCS should be mandated as BACT. A BACT requirement for CCS would apply over the life of the plant and carry with it the penalties for noncompliance that are provided by the Clean Air Act, up to and including mandatory closure of the plant.

---

[264] Christian County Generation, LLC-Taylorville, Illinois Class VI Permit Request (September 20, 2011 ("Class VI Permit Application"), *available at* http://www.epa.gov/r5water/uic/tec/pdfs/tec-permit-appl-201 1-09.pdf. (Commenter's Exhibit 58)

[265] "The Mount Simon Sandstone has been extensively developed for disposal and storage using Class I injection wells in Illinois and Indiana, and is the main deep saline candidate reservoir being targeted for CO_2 storage at this site. Three identified characteristics of the Mount Simon Sandstone, as determined by ISGS and the MGSC, make it very suitable for injection at Taylorville and the area near the proposed TEC #1 well:
1) The Mount Simon Sandstone is deep in the subsurface of the Illinois Basin and site 2D reflection seismic interpretation indicates it is laterally continuous in this area;
2) It is of sufficient thickness to be used for CO_2 storage;
3) Preliminary results of the MGSC project in Decatur suggest sufficient reservoir potential is present with porosity and permeability."
Class VI Permit Application at 37.

[266] According to the USEPA Region 5, "ADM proposes to inject CO_2 from its agricultural products and biofuel production facility. The goal of the project is to demonstrate the ability of the Mt. Simon geologic formation to accept and retain industrial scale volumes of CO_2 for permanent geologic sequestration. The CO_2 will be injected more than 5000 ft below ground level. The project has a projected operational period of five years, during which time 4.75 million metric tons of CO_2 will be injected. Following the operational period, ADM proposes a post-injection monitoring and site closure period often years. EPA received ADM's application for a permit for one CO_2 injection well in July 2011. It was assigned the identification number IL-115-6A-000 1. USEPA is reviewing the application for technical adequacy. (November 2011)" USEPA Region 5 at http://www.eya.gov/r5water/uic/adm/index.htm (December 2011)

CCG's references to the Schlumberger feasibility study and IEPA's discussion of this study in the Project Summary are not cursory and vague as the comment suggests. Both the application and Project Summary clearly acknowledge that this study was conducted and that the results of the study indicate the Mt. Simon formation may be a suitable storage reservoir target capable of permanently sequestering the CO_2 emissions from the AGR vent over the nominal 30 year life of the plant. In fact, the portions of this study cited by this comment were also included in the application. The IEPA, and the public, also had access to the full report by Internet. A fundamental problem with the comment's argument that the conclusions of this study directly make CCS a technically feasible control technology for BACT is that it fails to consider the preliminary and inherently speculative aspects of this "first phase in developing a geologic carbon dioxide (CO_2) storage site in the Mt. Simon formation." Although the Schlumberger study indicated favorable geologic conditions for CO_2 sequestration using the Mt. Simon formation, this preliminary finding does not constitute a guarantee that CO_2 injection will be available initially at startup or consistently over the life of the plant.

The various elements of the Schlumberger geologic storage feasibility study are just the first step of a much more comprehensive engineering and design analysis that will have to be developed through the Class VI injection well permitting process and as part of the initial construction and commissioning of the first injection well. The predictive geological modeling relied upon by Schlumberger is not based on actual core sampling for the specific site being considered, so it cannot be relied upon as a conclusive evaluation of the suitability of the specific portion of the Mt. Simon formation that is targeted for sequestration. Although the formation looks promising in its CO_2 retention capacity, given the current status of CO_2 sequestration technology, the formation's ability to adequately hold the volume of CO_2 produced by the TEC and to accommodate injection at the rate needed for the TEC is theoretical until demonstrated in practice, following actual well installation and injection of CO_2 over an extended period of time.

The comment points to the relatively small-scale CCS demonstration project currently being conducted by ADM in Decatur, Illinois as evidence that CCS in the Mt. Simon formation is technically feasible for the TEC. While the ADM project proposes to sequester CO_2 within the Mt. Simon formation, this does not establish CO_2 sequestration at Mt. Simon as a technically feasible BACT control option for the TEC. The comment points out that one "technical uncertainty in any sequestration project is the suitability of the geology," but it exaggerates the usefulness of the geological data already obtained from the ADM injection well drilling. Given the much smaller amount of CO_2 that ADM would inject in its demonstration project, that project has a much smaller geological footprint than would be presented with CO2 sequestration for the TEC. Subsurface geology can vary greatly over the 30 mile distance from Decatur to Taylorville. The For this reason, under the recently adopted Class VI Underground Injection Control (UIC) rules designed specifically to address CCS in deep geologic formations like the Mt. Simon formation, USEPA requires each project to conduct its own core analysis, formation testing, and updated CO_2 plume modeling after the well drilling process is completed. If any of this additional data indicates the local geology

and "injectability" of the formation is not suitable for long-term CO_2 storage, USEPA cannot grant authority for the facility to proceed with full-scale injection. Even if the formation is deemed to be suitable for long-term CO_2 storage but it is found to have less porosity and permeability than assumed in the model, additional wells will be required. The siting, development, and operation of additional wells will only add to the overall complexity of the system and will pose more opportunities for the system to fail to provide the required level of CO_2 sequestration.

Furthermore, the ADM injection well currently regulated under the Class I UIC rules is limited to 1 million metric tons over a three year period. In the Class VI UIC well application submitted in December 2011, ADM expressed plans to construct an additional well in Decatur site that would have an operational period of five years during which up to 4.75 million metric tons of additional CO_2 may be injected.[267] The injection field proposed for the TEC would receive over 60 times as much CO_2 over the life of the project as compared to the injection well that ADM is currently operating in Decatur. Under the Class VI permit application submitted by CCG, the permitted volume of the field could be as high as 4.5 million metric tons per year with an expected rate of 2.1 million metric tons each year. Over 30 years, this would result in 63 to 145 million tons of CO_2 being injected. With these increase in both injected volumes and the time of operation, it is possible the TEC field will have interruptions or require changes that would impact the field's ability to sequester CO_2. These same issues are not posed for the ADM project. As a voluntary demonstration project, ADM can have interruptions in the injection of CO_2. Changes to the project are much less likely because of it is smaller and because injection could be terminated. Thus, the same information and considerations relevant to an assessment of the Mt. Simon formation for the ADM project would not be determinative in assessing the suitability of this formation for the TEC. Moreover, the injection well at the ADM site only began operation in November 2011. With less than 6 months of operational experience, it is too soon in the demonstration project process to ascertain the effectiveness of CO_2 storage of CO_2 in the Mt. Simon formation.[268]

The comment also claims that the IEPA dismissed the three full-scale CCS projects proposed under the USDOE Clean Coal Power Initiative (CCPI) without giving each of the these projects additional consideration under Step 2 of the GHG BACT analysis for the AGR vent. The comment has mischaracterized the guidance in the NSR Manual used to support this claim. The quote from page B.17 of the NSR Manual specifically states that an applicant must assess the applicability of an available control option based on "an assessment of the similarities and differences between the proposed source and other sources to which the process technique had been applied previously."[269] The key statement in this quote is "had been applied previously." EOR has not been applied previously at any of the three facilities covered under USDOE's CCPI program because none of these facilities have completed construction much less commenced operation. Available control technologies are those that are proven at the

---

[267] **ADM, Class VI Injection Well Permit Application, December 2011, available at http://www.epa.gov/r5water/uic/adm/index.htm#overview**
[268] **DOE, *CO_2 Injection Begins in Illinois: Large-Scale Test to Inject 1 Million Metric Tons of Carbon Dioxide in Saline Formation*, November 17, 2011, available at http://www.fossil.energy.gov/news/techlines/2011/11058-CO2_Injection_Begins_in_Illinois.html**
[269] **Sierra Club/Natural Resources Defense Council, Comments January 3, 2012, fn. 193, p. 62.**

time of permitting and can be obtained through commercial channels, not those that may be demonstrated by sources in the future (and thus may become available for future projects in the same or similar industries). Not only have the three CCPI projects not demonstrated the use of EOR, but they are not "similar" sources in the context of the NSR Manual guidance simply based on an examination of their location relative to the location of the TEC. The only "explanation of unusual circumstances" necessary to show why EOR is not technically feasible for the TEC, as compared to the three CCPI projects, is its location relative to existing oilfields that are candidates for EOR. CCG specifically stated in the Application that the same EOR infrastructure that is available to the three CCPI projects is not available in Central Illinois since the closest existing pipeline is located more than 350 miles away in Mississippi (refer to page 6-6 of Volume 1 to the Application). The application also provides the distances from each of the three CCPI projects to the existing oil fields they will serve (refer to page 6-4 of Volume 1 to the Application). It should also be noted that CCS, via EOR or otherwise, has not been deemed technically feasible in the context of BACT at the three referenced CCPI projects.

As the comment points out, the final Class VI rule under the UIC program was adopted by USEPA in December 2010, and the GHG BACT analysis for the TEC was submitted to the IEPA in late October 2010, before this occurred.[270] The IEPA did not need to "correct" the statements in the application regarding the regulatory uncertainty posed by the lack of final Class VI rule. It was known that these statements were no longer relevant when the Draft Permit was released, more than a year after the GHG BACT analysis was originally submitted and more than 10 months after the Class VI rule was adopted. The comment seems to be confused on the timing of CCG's GHG BACT submittal in relation to USEPA adoption of the Class VI rule when it accuse CCG of making incorrect statements in the application. Additionally, the adoption of the rule did not eliminate regulatory uncertainty. While the Class VI rule has been adopted, the final implementing guidance documents have not. The draft guidance documents for the required monitoring and verification have yet to be issued. These guidance documents will likely provide critical information to both sources and regulatory personnel for ensuring the injection wells are properly designed, constructed, and operated safely. The lack of any final guidance further adds to the uncertainty as to the technical and other requirements that CCG will need to meet before full-scale CO_2 injection can occur.

Establishing a regulatory structure for geologic CO_2 injection and submitting an application seeking approval to drill a single injection well under this new regulatory framework does not resolve the challenges that CCG may face in attempting to demonstrate the feasibility of full-scale sequestration in the Mt. Simon formation.[271] CCG's submittal of a Class VI permit application in September 2011 is only a preliminary step in the long process of assessing the technical feasibility of long-term CO_2 injection and sequestration in the Mt. Simon formation. The permitting process is

---

[270] **Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells, 75 FR 77230, December 10, 2010.**

[271] **The UIC rules for underground CO_2 injection establish a new class of well (designated as Class VI) with associated requirements for 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.**

a lengthy, iterative process where several tests must be performed before operation of the well may be authorized, including formation testing, logging, sampling, and testing of the well and surrounding formations, and mechanical integrity tests.[272] Several levels of documentation are also required prior to authorization of well operation including final Area of Review (AOR) delineation, updates to geologic and hydrogeologic properties of proposed storage site and injection and confining zones, information on the compatibility of the CO_2 stream, results of formation testing, and final injection well construction procedures.

Even after a permit is issued, further periodic review is required to be submitted by the Permittee through the life of the project in order to ensure the injection process is safe and reliable. An iterative process of reviewing the implementation takes place, where the AOR Plan must be re-evaluated, and the Testing & Monitoring (T&M) Plan and Emergency and Remedial Response (ERR) Plan must also be reviewed for necessary amendments. If amendments are required based on the reevaluation of any of these plans, the owner develops new plans and submits them to the UIC Program Director for evaluation and approval.

The IEPA cannot guarantee the success of efforts to obtain a Class VI permit and maintain the authority to inject CO_2 over the lifetime of the TEC, nor can the IEPA require CCG to guarantee the success of its efforts. The ability to obtain a Class VI Permit depends upon information that is not yet fully assembled about the geology of the planned sequestration site and an administrative process for obtaining a permit that is new and accordingly cannot yet be considered predictable. For the IEPA to set a CO_2 BACT limit for the TEC premised on sequestration in the Mt. Simon formation, the long-term effectiveness of such sequestration cannot be in question. None of the testing and research conducted to-date on the Mt. Simon formation can be used to definitively confirm its long-term capabilities for storing CO_2. BACT limits must be achievable over the lifetime of the source on a continuous basis, so uncertainties regarding the effectiveness of a control option must be weighed heavily against the results of limited testing and studies that suggest the control option may be capable of reducing emissions for sometime in some limited circumstances. In contrast to evaluating the capabilities of CCS for reducing CO_2 emissions, the effectiveness of add-on control equipment for emissions of pollutants like PM and SO_2 can readily be assessed through information on previous applications of such equipment and performance data measured by established test methods and procedures, with little uncertainty whether these technologies can be successfully applied at an industrial scale to a variety of similar sources. The successful implementation of CCS at a candidate sequestration site is determined by a variety of complex factors which bear very few similarities to the types of factors that influence the effectiveness of common add-on control options like baghouses, scrubbers, and thermal oxidizers. CCG and the IEPA appropriately considered these site-specific factors in concluding that CCS is not the BACT level control option for reducing CO_2 emissions from the AGR vent or any other CO_2 emissions source at the TEC.

[272] **USEPA, *Underground Injection Control Geologic Sequestration Rule Training Workshop: UIC GS Rule Elements*, available at http://water.epa.gov/type/groundwater/uic/class6/upload/module03permitinfo.pdf**

62. The IEPA Erred in Its Analysis of Pipeline Resources for geologic sequestration of CO2 in conjunction with its use for Enhance Oil Recovery (EOR), as it determined that such sequestration is infeasible due to lack of EOR opportunities. The Project Summary writes off the possibility of EOR in connection with the project by stating that "[t]here currently is not a market for CO_2 from the proposed plant for EOR since CO_2 is not used in Illinois for EOR"; that "existing EOR practices cannot produce higher oil recovery rates in an economical manner"; and that "Illinois oil producers have no experience with conducting EOR at oil fields in the Illinois Basin" (Project Summary at 31). The Project Summary additionally makes no reference to other EOR opportunities in the Midwest outside of Illinois, referencing only a CO_2 pipeline that exists in connection with EOR operations in Mississippi. *Id.* These statements and omissions present a woefully inadequate characterization of EOR opportunities in Illinois and the Midwest region, and thus an impermissibly incomplete record for rejecting CCS. The real picture presents many opportunities not evaluated by IEPA, supporting that sequestration associated with EOR is feasible for the project.

A report prepared in 2006 by Advanced Resources International for USDOE ("ARI DOE Report")[273] states categorically that Illinois and Michigan Basin oil producers are familiar with using technology for improving oil recovery. For example, producers have used waterflooding in the Illinois basin since the 1950's to improve oil recovery. More recently, two small CO_2-EOR projects have been ongoing for nearly 10 years in Michigan.

ARI-DOE Report at 3-3. A report prepared in 2009 by Advanced Resources International for USDOE (2009 ARI DOE Report)[274] as an update to the 2006 ARI-DOE Report estimated that the economically feasible market for CO_2 for use in CO_2-EOR in the Illinois and Michigan Basins could be up to 421 million metric tons, assuming an oil price of $100/barrel and CO_2 costs of $60/metric ton.[275]

The Project Summary statement that "existing" EOR practices cannot function economically in Illinois is particularly misleading in light of the fact that the ART-DOE reports expressly distinguish between "traditional practices" technology, "state of the art"/"best practices" technology, and "next generation" technology for EOR, and discuss in detail the fact that state-of-the-art and next generation technology would render EOR more economical than traditional practices technology — which is defined as ". . .use of *past* CO_2 flooding and reservoir selection practices."[276] Specifically, the 2006 ARI-DOE report found that using "state-of-the- art" EOR practices would allow 500 million barrels of stranded oil to be recovered, even at $1.50 per Mcf CO_2 and $30/bbl oil prices. Oil prices equal to $40/bbl would allow 600 million barrels of stranded oil to be recovered. With an oil price of $40/bbl, CO_2 cost of $0.80/Mcf, and 15 percent rate of return hurdle, 630 million barrels of stranded oil could be economically recovered.

---

[273] Advanced Resources International, 2006, *Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Illinois & Michigan Basins*, prepared for U.S. Department of Energy, Office of Fossil Energy — Office of Oil and Natural Gas, 104 p. *available at* http://www.adv-res.com/pdf/Basin%20Oriented%20Strateies%20- %20Illinois Michigan Basin.pdf. (Commenter's Exhibit 59)

[274] Advanced Resources International, 2009, *Storing CO_2 and Producing Domestic Crude Oil with Next Generation CO_2-EOR Technology*, prepared for U.S. Department of Energy, National Energy Technology Laboratory, 74p.http://www.netl.doe.gov/energy-analyses/pubs/Storing%20CO2%20w%20Next%20Generation%20CO2- EOR.pdf. (Commenter's Exhibit 60)

[275] 2009 ARI-DOE Report at 53.

[276] 2006 ARI-DOE Report at 5-10 *et seq.*, 2009 ART-DOE report at 30 *et seq.* (emphasis added).

The 2009 ARI-DOE report estimated that the technically recoverable resources from applying "best practices" technology in the Illinois and Michigan Basins is 1.2 billion barrels and applying "next generation" technology is 3.2 billion barrels.[277] The report estimated that the economically recoverable resources from applying "next generation" technology would be 1.7 billion barrels using a base case of $70/barrel oil and $45/metric ton CO_2, delivered at pressure to the field.[278] A report prepared in 2010 by ARI for the Natural Resources Defense Council (2010 ARI-NRDC Report)[279] estimated that the economically recoverable resources from applying "best practices" technology would be 0.5 billion barrels and from applying "next generation" technology would be 1.7 billion barrels, assuming $70/bbl oil and $15/metric ton CO_2.[280] Using an oil price of $100/barrel, the approximate value at which oil is trading today, the 2009 ARI-DOE report estimated that 2.1 billion barrels could be economically recovered.[281]

Other studies of EOR opportunities in the Midwest have reached similarly optimistic conclusions concerning the availability of EOR opportunities in Illinois and surrounding states. A 2009 report prepared by Kinder Morgan for the State of Illinois' Department of Commerce and Economic Opportunity (Project Lincoln)[282] determined that in Illinois alone 300 million barrels of oil could be recovered using CO_2-EOR. The report concludes that initially just over 80 million cubic feet per day ("cfd") of CO_2 would be required on average, growing to almost 350 million cfd. And an additional study by ARI for the Midwestern Governors Association[283] found that 175 reservoirs in 8 of the 12 states represented by the MGA have CO_2 - EOR potential, with a technically recoverable resource up to 7.5 billion barrels. Illinois and Kansas combined have the largest resource potential, up to 4 billion barrels. Using a base case of $70/bbl oil and $45/metric ton CO_2, the Midwestern region could produce up to 3.9 billion barrels of oil using 830 million metric tons of CO_2. While transportation issues would need to be addressed in assessing the commercial viability of these opportunities, as noted above, general references to the need to construct a pipeline are insufficient basis for failing to conduct complete Step 2 analysis — particularly where, as here, there is strong evidence that pipeline construction would be affordable.

The existing EOR opportunities for CO_2 sequestration in the Midwest highlighted by the comment are not available to the TEC as a CO_2 control option for the AGR vent given their small size and the lack of favorable economics for creating a commercial market for CO_2 in the Midwest based on current EOR technology. The closest viable operating EOR site is located in Louisiana with a CO_2 pipeline originating at the Jackson Dome formation in Mississippi. EOR in Louisiana with a pipeline interconnection point in Mississippi was evaluated in the application, as discussed in the Project Summary, and it was appropriately eliminated on the basis of technical infeasibility (see Project Summary, page 31).

---

[277] 2009 ARI-DOE Report at 42.
[278] 2009 ARI-DOE Report at 46.
[279] Advanced Resources International, 2010, U. *S. Oil Production Potential from Accelerated Deployment of Carbon Capture and Storage*, prepared for Natural Resources Defense Council, 56p., *available* at http://www.adv- res.com/pdf/v4ARI%2OCCS-CO2-EOR%20whitepaper%20FINAL%204-2- 0.pdf (Commenter's Exhibit 61)
[280] 2010 ARI-NRDC Report at 11.
[281] 2009 ARI-DOE Report at 48.
[282] http://www.commerce.state.il.usiNRlrdonlyres/4FE157DB-C1F7-4F2B-B46B-5F71 8A08E88 1/0/IllinoisCO2PipelineReport2009O7l5.pdf. (Commenter's Exhibit 62)
[283] Ferguson, R., Advanced Resources International, 2009, *CO_2-Enhanced Oil Recovery Potential for the MGA Region*, prepared for Midwestern Governors Association, 30p, available at http://www.midwesterngovernors.org/Energy/CO2EORpotential.pdf.(Commenter's Exhibit 63)

The information in the ARI/USDOE study, *Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Illinois and Michigan Basins*, does not suggest that using CO_2 for EOR in the Midwest is an available technology under today's market conditions for Midwestern crude oil and anticipated sales prices for CO_2. In this regard, ARI/USDOE cites the aims and objectives of the report as follows. The remainder of the ARI/USDOE report fully acknowledges the barriers that have prevented CO_2-EOR from being utilized in the Midwest to recover the "stranded" oil reserves remaining after conventional extraction technologies can no longer be used to economically produce oil from the mature and declining oilfields in the Midwest.[284]

> **This report evaluates the future CO_2-EOR oil recovery potential from the large oil fields of the Illinois and Michigan Basin, highlighting the barriers that stand in the way of achieving this potential. The report then discusses how a concerted set of "basin oriented strategies" could help Illinois and Michigan Basin's oil production industry overcome these barriers helping increase domestic oil production.**
> **ARI/USDOE Report, p. 1-1**

> **The main purpose of this report is to provide information to these "stakeholders" on the potential for pursuing CO_2 enhanced oil recovery (CO_2-EOR) as one option for slowing and potentially stopping the decline in the Illinois and Michigan Basin's oil production.**
> **ARI/USDOE Report, p. 2-1**

Midwestern oil producers do not use CO_2-EOR currently both because a supply of CO_2 is not available and because the "traditional practices" for CO_2-EOR are not economical even assuming that a supply of CO_2 was available. The cited ARI/USDOE economic infeasibility finding does not need to be considered in a cost effectiveness analysis in Step 4 of the BACT analysis for EOR, but instead goes to the availability of EOR technology. If owners of oilfields in the Midwest are not willing to accept CO_2 to conduct EOR based on traditional practices, no market currently exists for any of the CO_2 that the TEC could provide. The availability of CO_2-EOR in the Midwest is not determined by the technical feasibility or costs of constructing a pipeline, but is determined by the willingness of oilfield owners to accept and use CO_2.

ARI/USDOE also identify many technical and market based barriers to large-scale CO_2-EOR in the Midwest which have prevented this technology from being available to industrial producers of CO_2 as a means for reducing CO_2 emissions. The comment intentionally overlooked these clear findings of the report and instead chose to focus on the various future-looking statements and figures that ARI/USDOE generated to assess the "potential" of CO_2-EOR in the Midwest assuming that all of the current technical and economic barriers could be overcome. The January 2009 DOE report cited by the

---

[284] **The two key findings from the report that best characterize the current realities of CO_2-EOR technology in the Midwest are as follows: "4. Under "Traditional Practices" CO_2 flooding technology, high CO_2 costs and high risks, pursuing Illinois and Michigan Basin's "stranded oil" is not economically feasible." (Page 1-4), and "11. A public-private partnership will be required to overcome the many barriers facing large scale application of CO_2-EOR in the Illinois and Michigan Basin's oil fields**." (page 1-8)

comment, *Storing CO_2 and Producing Domestic Crude Oil with Next-Generation CO_2-EOR Technology,* only further highlights that current CO_2-EOR has not been successfully implemented in the Midwest at the scale required for the TEC.

Based on a 2008 EOR Survey published by the Oil and Gas Journal referenced in the DOE study, approximately 250,000 barrels per day of incremental domestic oil is being produced by 100 CO_2-EOR projects, most of which are located in Texas and the Gulf Coast region. The only EOR project currently in operation in the Midwest is located in far Northern Michigan. The Antrim natural gas processing plant provides approximately 225,000 tons of CO_2 per year separated from natural gas to Core Energy's oilfields in the Northern Silurian Reef to produce approximately 15,000 barrels per day of oil through CO_2-EOR.[285, 286] The potential CO_2 emissions from the AGR vent are more than ten times the amount of CO_2 that is currently being injected at the Core Energy site. The closest location of the Northern Silurian Reef to the TEC measured with a straight line is 350 miles. A CO_2 pipeline from the TEC to the Michigan EOR sites would be even longer since it would have to traverse through a much more circuitous path to avoid major cities and areas of dense population. Therefore, the Michigan EOR sites are no closer to the TEC than the existing Mississippi EOR sites evaluated in the Application and Project Summary. Based on Denbury's proposed pipeline (refer to Figure 6-1 of Volume 3 to the Application), the Mississippi EOR sites have proven capacities that could accommodate the CO_2 production from several industrial sites simultaneously while the Michigan EOR sites could not even handle a fraction of the production from a single site. Since both CCG and IEPA have clearly demonstrated EOR in Mississippi is technically infeasible, EOR in Northern Michigan would also be infeasible.

As discussed in the response to other comments, USEPA has clarified what constitutes "demonstrated technology" for the purposes of permit determinations with respect to CCS in its GHG BACT Guidance. On page 36, this guidance indicates that technical infeasibility can be established if the permitting record shows that an available control option has neither been demonstrated in practice nor is available and applicable to the source type under review. Full-scale EOR using CO_2 produced by an industrial facility in the Midwest has not been demonstrated in practice at any location. While Denbury, the Midwest Governor's Association and the USDOE expect that CO_2-EOR technology may become available in the future, it is not yet available and should thus not be considered technically feasible for the AGR vent BACT analysis (or the BACT analysis for any other CO_2 emissions sources at the TEC).

63. The IEPA failed to explain why various legal and financial questions rise to the level of "logistical hurdles" for the project under Step 2 of the BACT analysis, the "Technical Feasibility Inquiry." The IEPA makes vague references to the need for legal/regulatory frameworks for CCS, market failures related to climate policy, questions of long-term liability and public information campaigns in its discussion of CCS. *See* Project Summary at

---

[285] **http://coreenergyholdings.com/GeologicCO2Sequestration.html**

[286] **Society of Petroleum Engineers, EOR Potential of the Michigan Silurian Reefs using CO_2 (SPE 113843), 2008, available at http://science.uwaterloo.ca/~mauriced/earth691-duss/CO2_General%20CO2%20Sequestration%20materilas/Toelle%20B.,%20et%20al.%20(2008)%20-%20EOR%20Potential%20of%20the%20Michigan%20Silurian%20Reefs%20Using%20CO2.pdf**

30-31, 32.[287] It is unclear in the Project Summary the extent to which IEPA relied on or gave weight to these factors in its determination of Step 2 technical infeasibility, but any such reliance was both factually unsupported and legally impermissible. Non-technical factors — particularly where they are grounded in factual error or are not shown to be applicable — are neither cognizable nor appropriate in a BACT Step 2 analysis. As discussed in my comments, to the extent that these concerns are related to the UIC program, they are generally invalid from a factual standpoint as they have for the most part been fully addressed in USEPA's Class VI rulemaking. Additionally, IEPA has failed to explain the relevance of the very general non-technical factors to the specific project at hand.

These were only a few of the numerous facts and circumstances relied upon in IEPA's BACT determination. The downplaying of these "non-technical" issues in the comment does not diminish the facts that CCS has not been demonstrated at this scale anywhere in a manner that would meet the relevant requirements of the Clean Air Act.

Further, USEPA effectively acknowledged these circumstances in the preamble to its proposed NSPS for GHG Emissions for Electric Utility Generating Units, as published in the Federal Register on April 13, 2012. In the preamble of this proposed rulemaking, USEPA points to a number of demonstrations projects for CCS technology and to planned proposed projects that would use CCS. However, as USEPA points to Great Plains Gasification, it does not identify a full-scale coal gasification plant that has used CCS as a freestanding technology, independent of use of CO_2 from the plant for enhanced oil recovery (EOR). Moreover, the other cited sequestration projects are associated with production of petroleum and/or natural gas, with CO_2 contained in the raw extracted material being sequestered geologically after the CO_2 is removed from the material. At a minimum, this means that there are specific aspects of the location of the projects and underlying or nearby geology that act to support sequestration of CO_2.[288] USEPA also specifically acknowledged issues with respect to geologic sequestration of carbon that are as yet not resolved:[289]

> **[E]ven for sources installing and operating CCS at the beginning of a project, there may be startup issues (other than those related to the capture technology or the arrangements for sequestration). For instance, a company's ability to sequester CO_2 may be dependent upon construction by a third party of a pipeline that will be transporting the CO_2 to a site to be used for enhanced oil recovery or permanent sequestration. Because the owner or operator does not have direct control over this part of the project, there may be concerns that it will not be completed on time and that even after spending all of the money to**

[287] IEPA generally referenced the following as supposed hurdles to implementation of CCS:
(1) The Facility is not one of the three United States Department of Energy ("USDOE") IGCC demonstration projects (Project Summary at 30).
(2) The federal Interagency Task Force August 2010 report identified four "near-term and long-term concerns for the full-scale commercial application of CCS," including (i) the lack of climate policy to set a price on carbon and encourage emission reductions, (ii) the need for a "legal/regulatory framework" that facilitates reject development and "provides public confidence" in CCS; (iii) clarity with respect to long-term liability for sequestration and (iv) the need for "integration of public information, education, and outreach throughout the lifecycle of CCS projects in order to identify key issues, foster public understanding, and build trust between communities and project developers." *(Id.)*

[288] Standards of Performance for Greenhouse Gas Emissions for New Stationary Sources: Electric Utility Steam Generating Units (77 FR 22,392, April 13, 2012 (refer to pages 22,413 through 22,417)

[289] As USEPA also proposes a "30-year Averaging Compliance Option," with staggered emission limits for CO_2, with a more stringent limit taking effect in the 11th year of operation of a subject source (proposed 40 CFR 60.5520(b)) and would exclude certain transitional projects from the proposed standards, USEPA further acknowledges the current status of CCS as a technology that is still under development.

construct a coal-fired unit capable of capture, it will have to remain non-operational for a period of time until the pipeline project or sequestration destination is completed. [77 FR 22407]

Regulatory uncertainty may be hindering the development and deployment of CCS, as evidenced by American Electric Power (AEP)'s recent deferral of a large-scale CCS retrofit demonstration project on one of its coal-fired power plants because the State's utility regulators would not approve CCS without a regulatory requirement to reduce CO_2. [77 FR 22396]

64. The IEPA has also failed, as noted above, to explain why the existence of three full-scale IGCC projects (Project Summary at 30) weighs *against* requiring CCS at the TEC rather than in favor of it.

These three projects were mentioned to highlight the fact they are part of a USDOE demonstration program for CCS and have, therefore, CCS is incorporated into their design for this reason. These projects were not mentioned to show that these projects or the respective permitting authorities have determined that CCS is technically feasible as BACT. It should also be noted CCS is not required by the air pollution control permits for any of these projects and none of the three have yet been constructed. More generally, the fact that USDOE is engaged in a program to develop CCS technology constitutes direct evidence to show that this technology is not currently demonstrated and cannot yet be considered commercially available.

65. IEPA has also not provided any reason why general purported "market failures" regarding carbon would affect the *technical* feasibility of CCS *at this plant.* The Agency has likewise failed to explain how and why the lack of full legal and regulatory frameworks for CCS projects in general (at best a severe exaggeration of current circumstances given the new Class VI rule discussed above) would stand in the way, as a *technical* matter, of creating permit conditions that protect human health and the environment and that provide for long-term liability for sequestration (particularly when the Class VI Permit Application contemplates exactly such terms). The IEPA simply provides a laundry list of items that is almost entirely irrelevant to the case-by-case technical assessment required by BACT.

The Class VI rule in the UIC program generally define what will be required to demonstrate sequestered CO_2 will not impact drinking water supplies. What it does not do is prove in any way that sequestration will be successful at the scale required at the TEC. It is important to note that CCG has not yet secured its Class VI permit and may not. To the extent it does, the conditions of such permit are unknown at this time and, again, it will not assure the success of sequestration. The 'laundry list" cited in the comment is a communication from the Interagency Task Force for Carbon Capture and Storage regarding their concerns on the full-scale commercial application of CCS. Each of these concerns applies to TEC as it would for any site and further demonstrates, in addition to the site-specific issues addressed elsewhere in this response, that CCS is not technically feasible at this time for TEC. Further, USEPA acknowledged the following in the preamble to the proposed GHG NSPS:

This [30-yr averaging period] compliance alternative allows owners/operators to install CCS when the unit is first constructed but also provides the operational flexibility that may be necessary to optimize the performance and to have additional time to address any startup challenges related to issues such as business arrangements related to the sale or storage of the captured CO_2. [22399]

66. The IEPA failed to demonstrate that overwhelming hurdles justify the omission of a detailed, case-by-case BACT analysis. For all of the reasons discussed above, IEPA has not even come close to demonstrating that it may avail itself of the very narrow allowance in the USEPA guidance for a more limited Step 2 analysis in circumstances where "significant and overwhelming technical (including logistical) issues associated with the application of CCS" allow for a "less detailed justification" of the technical feasibility of CCS in Step 2.[290]

Contrary to the assertion in the comment, IEPA's evaluation of CCS in the BACT analysis was thorough and consistent with USEPA guidance, and did not rely on any purported allowance for a more limited step 2 analysis. CCS, CatOx supplemental fuel selection, and gasification block process efficiency were all evaluated as available technologies for the AGR Vent. CCS was found to be technically infeasible as a result of a comprehensive, seven-page analysis. The proposed CO_2 BACT limit for the gasification block (111.4 tons CO_2e/million scf SNG produced) was ultimately based on process efficiency as the BACT analysis demonstrated TEC would be 15-22% more efficient than other proposed SNG projects (Cash Creek and Power Holdings).

67. In the first instance, as discussed above, "CO_2 transportation and sequestration opportunities already exist in the area where the source is" — in the form of the ADM project and the Mt. Simon formation — thus clearly warranting a "detailed case-specific analysis" before dismissing CCS as infeasible pursuant to the USEPA Guidance. In this regard, I note that the need for, at most, a very short (approximately 30 mile, as discussed below) pipeline is insufficient basis to simply wave away the possibility of CCS for the plant, in view of both the *In re Mississippi Lime* decision that the need to construct a pipeline is not a *per se* demonstration of infeasibility, and the data I present below showing that the cost of a pipeline would be far from prohibitive.

There is nothing in the record to suggest the ADM sequestration site is capable of storing the volume of CO_2 from TEC for 30 years, even if a pipeline could be built. As discussed elsewhere in this response, the ADM sequestration demonstration project is much smaller than would be required for TEC. Further, with less than six months of operating history, this pilot project is far from complete.

68. Faced with a project applicant that informed the Illinois legislature and others that it would sequester CO_2 emissions, IEPA has blindly accepted contradictory statements from the applicant that sequestration is not technically feasible without even acknowledging, much less attempting to address, this inconsistency.

[290] USEPA GHG BACT Guidance at 36.

This purported "inconsistency" has been considered and addressed. The fact that the CCPSL would require at least 50 percent of the CO_2 to be sequestered does not mean that sequestration is technically feasible for the purposes of BACT under the PSD program. The sequestration requirement of this law was not based on any scientific or technical analysis by a knowledgeable authority with respect to the feasibility of sequestration. Further the penalties provided for under this law for failure to meet the specified level of sequestration are very different from those that would be provide for under the Clean Air Act.

69. In short, IEPA has wholly failed to either evaluate the technical feasibility of CCS pursuant to Step 2, or to demonstrate why thorough case-specific analysis of feasibility was unnecessary. Had it conducted a proper analysis, the Agency would have been compelled to conclude that CCS is, indeed, technically feasible for the Project, just as CCG's own consultant Schlumberger concluded earlier.

The Schlumberger report did not conclude that CCS is technically feasible as BACT. The report summarized that the study results indicate, based on 2D seismic work and computer modeling simulations, the proposed sequestration site has sufficient porosity, permeability, and capacity to store the projected amounts of CO_2 over the expected life of the TEC. However, this is insufficient for purposes of demonstrating technical feasibility of a control technology as BACT.

70. Because, as described below, CCS is also cost-effective for purposes of BACT, the IEPA must establish enforceable emission limits in any final permit for the CCG facility that reflect the capture and sequestration of 90% of the CO_2 from the vent for the AGR unit. At a minimum, IEPA must perform a proper analysis of the technical feasibility of CCS, with respect to both the Mt. Simon formation and EOR opportunities, and re-notice the permit in draft to allow for public comment on the more complete analysis.

A proper technical feasibility analysis was conducted for sequestration and correctly concluded that sequestration is not feasible. This precludes the need to evaluate cost effectiveness under Step 4 of a top-down BACT analysis. Further, there is no basis for concluding the BACT limit should be 90%, which is wholly arbitrary and not supported by material in the record.

71. The proposed BACT determination for CO_2 BACT is based on unnecessary errors of fact and law. Pursuant to the Clean Air Act, application of BACT shall "In no event…result in emissions of any pollutants which will exceed the emissions allowed by any applicable standards established pursuant to section 111 or 112 of this Act." 42 U.S.C. § 7479 (3) Because the TEC is an EGU, it must be subject to facility-wide BACT limits that are consistent with 40 CFR 60 Subpart Da, as this NSPS is in place at the time the permit is finalized.[291] At the very least the IEPA must consider and evaluate the application in light of changed regulatory requirements arising before the permit decision is finalized.

[291] *See Ziffrin v. U.S.*, 318 U.S. 73, 78 (1943) (commission required to apply the law that is current at the time the permit is issued, not at the time the application is filed); *In re: Phelps Dodge Corp*., 10 E.A.D. 460, 478 n.10 (E.A.B. 2002) (permit issuing authority is obliged to apply the statute and regulations in effect at the time the final permit decision is made); *In re: Dominion Energy Brayton Point, LLC*, 12 E.A.D. 490, 614-616 (EAB 2006)

Rather than treating the plant as an EGU, however, the Draft Permit would set separate BACT standards based on efficiency for the gasifier, and on efficiency and good combustion practices for the turbine. Both CCG and the IEPA fail to investigate the availability of an adjustable CCS based BACT limit rate for the whole electric generating facility. Such adjustable rates have been used in several instances where a new control technology or method is introduced. *See In re Hadson Power 14 – Buena Vista*, 4 E.A.D. 258, 288 (E.A.B. 1992) (basing BACT emission limits on the first application of selective catalytic reduction technology for a spreader-stoker boiler at a coal-fired plant); *In re AES Puerto Rico L.P.*, 8 E.A.D. 324, 347 (E.A.B. 1999) (setting BACT emission limits for PM_{10} that included condensible particulate and the use of a new test method, though there was very little information on which to base such a limit from the particular units). An adjustable BACT emission limit is clearly an option here, as CCG has proved the availability of carbon capture, and the full, updated and corrected record for this permit would show that CCG expects implementation of geologic sequestration for this plant (and when available, pipeline shipment of the captured CO_2 and transport for use in enhanced oil recovery). Unfortunately, without that information and analysis, the application and proposed approval are incomplete, and based on significant errors of fact and law that must be corrected before any permit is issued.

Initially, IEPA errs by asserting – through its proposed BACT limits – that CCS technology is not available at this site as a factual matter. CCG proves that capture technology is available for this plant, and indeed the gasifiers' design incorporates such technology into its design as "capture or separation of CO_2 is inherent in coal gasification for production of SNG." Project Summary at 29. CCG further notes that demonstrated technology for such capture of CO_2 from syngas exists as shown by at least four U.S. plants. *Id.* at 29 n.24. For the TEC, there is no doubt that capture of CO_2 is available.

Moreover, CCG, in a separate forum, in its application to USEPA for a Class VI Well Permit, has proved the availability of sequestering TEC's captured CO_2. As the Class VI Well Permit application indicates, "[t]he results of the geologic and reservoir evaluation study indicate that the [chosen site] has sufficient porosity… and permeability…, and therefore provides a storage reservoir target suitable and capable of accommodating all of the CO_2 produced by the TEC over the planned operational life of 30 years." Appendix A, UIC Permit Request – Area of Review and Corrective Action, at 10. Unfortunately, CCG did not update its PSD application to reflect the UIC Permit Request, and, IEPA fails even to mention the UIC Permit Request in its Project Summary, even though CCG submitted it on September 20, 2011, nearly four weeks before IEPA's October 17, 2011 Draft Permit. My expert affirms the availability of geologic sequestration of CO_2 at and in the vicinity of the TEC site. *See* the Affidavit of Dr. Bruce Hill accompanying my comments, paragraphs 3-12 (determining after reviewing available material that CCG's chosen site holds substantial promise for geologic carbon sequestration). By contrast, CCG and IEPA assert that sequestration is not available at the site because there is no currently existing pipeline for the offtake of captured CO_2.[292] Project Summary at 31. That no pipeline to enable enhanced oil

[292] IEPA also asserts that sequestration generally is unavailable, citing the now year-and-a-half-old *Report of the Interagency Task Force on Carbon Capture & Storage*, which is neither specific to this plant, location nor up to date as of the time of the draft permit issuance. *See* Project Summary at 30 and note 28. The Task Force report came out before the federal regulatory framework for CCS was finalized in December 2010, and before the proposal and development of several full scale projects including CCS technology as discussed by the applicant. *See* Project Summary at 30-32.

recovery currently exists does not mean there is no means to accommodate a lower CO_2 BACT emission limit, however. And as noted above, CCG failed to update the application when it filed for a Class VI UIC permit for on-site sequestration. CCG's application and the BACT determination are therefore incomplete and out of date due to IEPA's error in concluding CCS is not available at the TEC site.

Apart from the factual availability of carbon sequestration, IEPA errs by failing to consider CCS in light of CCG's objective to qualify as a "clean coal facility" under the Clean Coal Portfolio Standard Law, PA 95-1027, recently passed by the Illinois Senate. As stated above, to qualify as a "clean coal facility" under this law, CCG must capture and sequester at least 50% of the CO_2 emissions for a facility that plans to begin operation before 2015. 20 ILCS 3855 §1-10 (2011) (definitions). If the facility is to commence operation in 2016 or 2017, the capture percentage rises to 70%, and after 2017 it rises to 90%. *Id.* Furthermore, to be an "initial clean coal facility" – and to receive many of the financial benefits – the facility must make such CO_2 reductions "when commercial operation commences." 20 ILCS 3855 §1-75(d)(3) (2011).

IEPA also made errors of law regarding CCS in its acceptance of the applicant's BACT analysis regarding CO_2. First, IEPA failed to even evaluate the possibility of an adjustable BACT limit, despite the availability of such a limit in circumstances similar to those under consideration here. For example, in *Hadson Power*, the Environmental Appeals Board ("EAB") upheld a BACT limit for nitrogen oxides (NO_x) that set both a design limit and a worst-case limit in a case of the first application of a particular control technology to particular unit in this country. *Hadson Power*, 4 E.A.D. at 288-90. The permit allowed the permitting authority to revise the emission limit downward toward the design limit after operation commenced to reflect the emission rate that was demonstrated to be consistently achievable. *Id.* at 291. Similarly, the EAB has affirmed an adjustable limit, *see AES Puerto Rico*, 8 E.A.D. 324 (EAB 1999), for the control of a pollutant that would otherwise go uncontrolled, and where a new test method was to be employed, so that there was therefore little information on which to base an emission limit for that pollutant at the time the permit was finalized. *Id.* at 348-50. IEPA must evaluate similar adjustable CO_2 emission limits here, based on the demonstrated potential for sequestration, accompanied by a worst-case limit (likely based on the same principles as in the current draft permit) in the unlikely event that sequestration later is shown to be impossible.

Additionally, IEPA wrongly interpreted the legal availability of CCS by its acceptance of CCG's BACT analysis, which erroneously dismisses CCS in the first step. The applicant impermissibly eliminated CCS technology at the first step of its analysis, arguing that carbon sequestration is not "commercially available" – even though it subsequently applied for a permit for onsite sequestration. Application, Vol. 3 at 6-6. "Commercial availability" of a technology is not the proper standard to apply under step one, however. Step one merely requires IEPA to identify all available control technologies and list them to allow for a proper evaluation of all potential limits. *See In re Desert Rock, Energy Company, LLC*, 14 EAD ---, Slip op. at 70 (Sept. 24, 2009)(noting that where a technology is potentially available at a site, dismissal of the technology without evaluation is impermissible). This is a

simple analysis in this case, because [f]or the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is 'available' for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams…. For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs.

PSD and Title V Permitting Guidance for Greenhouse Gases, 32 (March 2011) ("GHG BACT Guidance"). IEPA erred by removing – instead of listing – CCS in the first step of the CO_2 BACT analysis for the TEC.

Because IEPA erroneously accepted CCG's unlawful CO_2 BACT analysis, it also erred by failing to further evaluate partial on-site capture and sequestration as a control option – to be implemented through an adjustable BACT emissions limit -- in steps two through five. In the first step, as stated above, CCS should be listed as an "available" control technology and thus move on to the second step, where technically infeasible options are eliminated. *See* GHG BACT Guidance at 33. As noted above, CO_2 capture and sequestration are available and technically feasible from this facility at this location, based on the CCG's own submissions.

Statements and representations by Tenaska make clear that it views CCS as technically feasible at this location, and CCS therefore must remain on the list of available controls after Step 2 of the Greenhouse Gas BACT analysis. Step 3 in the analysis then calls for the ranking of the remaining control technologies, based on the total CO_2e, with the most effective listed at the top. Clearly, given the CCG's stated intention to sequester approximately half of the CO_2 from the TEC, CCS remains at the top of the list going into Step 4 of the BACT analysis. Step 4 requires permitting authorities to consider the economic, energy and environmental impacts of the ranked control technologies "to either confirm that the top control alternative is appropriate or determine it to be inappropriate." After analyzing these impacts, Step 5 calls for the permitting agency to choose the most effective control option that was not eliminated in Step 4. Without IEPA's error of law, the five-step Top Down BACT analysis would result in the choice of CCS as the basis for the CO_2 BACT emission limit.

As USEPA clearly stated, CCS is "available" under Step 1. *Id.* at 32. When analyzing for technical infeasibility under Step 2, "CCS may be eliminated…if it can be shown that there are significant differences pertinent to the successful operation for [CO_2 capture and/or compression, transport, and storage] from what has already been applied to a differing source type." *Id.* at 35. However, in order to dismiss CCS in a case "where CO_2 transportation and sequestration opportunities already exist in the area where the source is, or will be, located,…a fairly detailed case-specific analysis would likely be needed…." *Id.* at 36. This is exactly the situation the applicant and IEPA face, as the TEC is currently planned to be located on a site where sequestration opportunities already exist. Yet, IEPA did not give a detailed, case-specific analysis of CCS but merely dismissed it before even reaching this step.

As shown above, moreover, CCS is not technically infeasible at this location, and IEPA cannot eliminate it under Step 2. Moreover, as even partial capture and sequestration of the

CO_2 emitted by the TEC removes more CO_2 than any other combustion and efficiency practices considered by IEPA in the GHG BACT review it did conduct, CCS should remain atop the list after Step 3.

Considering the cumulative impacts in Step 4, CCS would not be eliminated as IEPA must determine (based on a properly supplemented record and on the case-specific facts already presented by the applicant) "that while [CCS] has higher economic costs, those costs are outweighed by the overall reduction of emissions of all pollutants that comes from that higher efficiency." *Id.* at 44. Thus, a proper CO_2 BACT analysis would result in the selection of at least partial CO_2 capture and sequestration as the basis for a BACT limit after the Step 5 of the BACT analysis.

This comment does not support a change in the status of geologic carbon sequestration for the TEC. As discussed in detail in responses to other comments on this subject, sequestration continues to be technically infeasible for the TEC. That is, while it is expected that sequestration will be doable for this project, it cannot currently be assured that this will be the case.

Indeed, this comment provides further confirmation that sequestration should not be considered feasible. The Affidavit accompanying this comment, as characterized by the comment itself, indicates that CCG's chosen site holds <u>substantial promise</u> for geologic carbon sequestration. As such, it confirms uncertainty about the achievability of sequestration technology for the project. BACT cannot be established based upon substantial promise for success.

72. CCS is cost-effective pursuant to Step 4 of the BACT analysis. As discussed in *Mississippi Lime Company*, issues of cost associated with control technologies are required to be addressed in Step 4 of top-down BACT analysis rather than Step 2. IEPA does not directly reference cost at all in its evaluation of CCS in the Project Summary. However, it implies that the cost of pipeline construction would be prohibitive, since the only pipeline option it chose to evaluate was construction of a pipeline by a third party at its own expense. *See* Project Summary at 31. Had IEPA performed a Step 4 analysis, however, it would have determined both that CCS is cost effective in terms of the costs of capture, transportation and sequestration per ton of CO_2 for purposes of Step 4.

As discussed in the Project Summary, the capture of CO_2 "is inherent in coal gasification for production of SNG" (Project Summary at 29, n.23), which means that CCG's proposed production of SNG will create a high purity stream of CO_2 at the gasifier block as part of normal operations, *i.e.*, whether or not the project must sequester the carbon it produces. As such, the cost of capturing CO_2 need not and should not be counted as part of the cost of doing CCS at the CCG Facility. This, in and of itself, goes a long way toward making CCS cost effective for the Facility, since the bulk of the cost of any given CCS project of this kind lies in the capture of CO_2 rather than its transportation or sequestration. General information on the cost of CCS available from a variety of sources, including the 2005 *IPCC*

Special Report on Carbon Dioxide Capture and Storage.[293] Some reports simply ignoring the cost of transport and storage entirely as being negligible compared to capture costs.[294]

The relatively low cost of CO_2 transport and geologic sequestration is in line with the findings of the Schlumberger Cost Study with respect to the proposed plant, which states only very modest costs for sequestration. That Study found that the cost of sequestration comes in at a total of $116,717,679 for the lifetime of the project. This is small compared to the total capital costs for the plant, which would be several billion dollars. In addition, the Study found the cost of sequestration for the plant to be significantly lower than the typical CCS cost range of $5 to $10 per metric ton of CO_2 given the very favorable geology of the Mt. Simon formation:

> Based on Schlumberger Carbon Services evaluation and understanding of project requirements, including pending regulations, costs for typical carbon storage projects are likely to be in the range of $5.00 to $10.00 per tonne of stored CO_2. The project costs presented herein are lower than this range due to the very favorable geologic setting, the assumptions concerning project requirements, and other conditions for CO_2 injection specific to the Taylorville Energy Center (TEC). This project and cost report should not be considered representative or typical of other CO_2 storage projects. Schlumberger Cost Study, page 1.

There are two additional reasons why sequestration costs might be even lower for CCG than those estimated by Schlumberger. First, significant and valuable site characterization has already been performed as part of the ADM Decatur project. If CCG were to use the Mt. Simon formation for sequestration, site characterization costs would be reduced as data is already available and an assessment without prior knowledge, as Schlumberger assumes in its cost estimates, would likely not be necessary. Second, the largest cost component is the proposed 4D seismic monitoring, at $33,034,500. Although this technique has been used successfully in other projects, it is not mandatory according to USEPA rules, nor is it essential everywhere for proving the suitability of an area for sequestration. It could be replaced with other techniques that are less costly - 4D seismic is one of, if not the most expensive, all the monitoring techniques available today.[295]

Outside of capture and sequestration costs, the other potentially significant costs associated with CCS at for the TEC are those of compression and pipeline transportation. I was not able to identify the costs associated with compression only for CCS at the plant from the permitting or other publicly available documents. I note that the "capture" costs reported by the IPCC above include the costs of compression, and that the costs of capture and compression together for this plant likely will be consistent with the ranges in the IPCC report. It should be noted that the gasification and methanation process produce CO_2 at high pressure, thereby reducing any potential compression costs for CCS.[296] A short pipeline,

---

[293] http://www.ipcc.ch/pdf/special-reports/srccs/srccs wholereport.pdf.
[294] M. Al-Juaied and A. Whitmore, *Realistic Costs of Carbon Capture* (Discussion Paper July, 2009) at 8, *available at* http:/Thelfercenter.ks.harvard.edu/files/2009 AlJuaied Whitmore Realistic Costs of Carbon Capture web.pdf.(Commenter's Exhibit 65)
[295] Other possible geophysical methods are referenced at http://www.netl.doe.gov/technologies/carbon seg/corerd/mva.html and http://www.netl.doe.gov/technologies/carbon seg/refshelf/MVA Document.pdf
[296] The Class VI Permit Application at *95* explains as follows:
4.14.5 Injection Pump(s). The CO_2 will be compressed within the power plant and delivered to the injection well field under pressure. No injection well pumps will be required to deliver the captured CO_2 to the injection wells due to the fact that high pressure exists from the capture and

which is a key option for the plant, would also decrease the need for compression. In any case, CCG has not provided any data on potential compression costs and no credible argument has been put forward that such costs would be significant or that compression might render CCS at the plant non cost- effective.

As far as a CO_2 pipeline, available data indicate that this cost will also not be significant. The Schlumberger Cost Study sets the cost of a pipeline to a sequestration site as ranging from approximately $4.3 to $7.1 million, with the high figure being based on a conservative case for the number of injection wells that may be required. From all indications, at most a very short pipeline is all that is needed in order for the TEC to sequester its captured CO_2. The Schlumberger Cost Study, page 1, assumes this to be the case, stating "the target area is under and adjacent to the plant resulting in minimal pipeline cost."

Additionally, the Facility Cost Report, at page 80, indicates that if the Denbury pipeline EOR approach to dealing with the CO_2 emissions from the TEC were not available, CCG would "proceed with its backup plan to construct its own storage field under and just north of the TEC Site." CCG could therefore plausibly drill injection wells in the immediate vicinity of the plant. However, none of these facts are discussed in the BACT Analysis in the application or in the Project Summary, nor are cost estimates for a plausible pipeline path presented.[297]

In fact, when CCS costs are calculated in terms of cost per ton of CO_2 sequestered, as is appropriate in Step 4, CCS at the plant appears eminently cost effective. Although the Schlumberger Cost Study does not calculate a cost per ton for CCS, as noted above, it concludes that such cost is lower than the $5.00 to $10.00 cost per ton range for a "typical" CCS project due to the favorable geologic setting. I used the cost information provided in the Schlumberger Cost Study to prepare a conventional BACT cost effectiveness analysis, using the USEPA Air Pollution Control Cost Manual, 6th Ed., January 2002. My analysis, indicates the cost effectiveness of capturing and transporting the CO_2 is $8.82/ton. Actual cost effectiveness would be lower if the Schlumberger data already include compression costs[298] or if credit were taken for sale of recovered CO_2. As noted on page 59 of the Facility Cost Report, the costs of carbon storage can be offset by EOR revenues where available.[299] In addition to this observation in the Facility Cost Report, CCS costs would be further offset by "an increase in the applicable tax credit from $10 to $20/MT under Internal

---

compression process that will drive the CO_2 to the injection wells. The CO_2 will be compressed using two 50% capacity 8 stage integrally geared centrifugal compressors. Each compressor will be driven by an approximately 19,500 horsepower electric motor. The compressors will be equipped with intercoolers and after coolers to prevent excessive discharge temperatures. Flows and pressures will be controlled by inlet guide vanes using suction and discharge pressures as control points. In the event the inlet guide vanes are at the maximum travel distance, the system will recycle or vent CO_2 to prevent an over or under pressure situation. The compressor will have an emergency shutdown system. In the event a line leak or overpressure situation is detected, the emergency shutdown system will be activated to shut off flow of CO_2 to the pipeline.

[297] A 2010 report by the Interstate Oil and Gas Compact Commission-Southern States Energy Board found the upper-bound cost of pipeline construction — represented by the Green Pipeline in Louisiana, which was required to cross through sensitive wetlands — was $93,750/in, diameter/mile. *See* IOGCC-SSEB, *A Policy, Legal, andRegulatory Evaluation of the Feasibility of a National Pipeline Infrastructure for the Transport and Storage of Carbon Dioxide* 2010, ("IOGCC-SSEB") *available at* http://www.sseb.org/downloads/pipeline.pdf. (Commenter's Exhibit 68) To be extremely conservative I could further assume, for argument's sake that CCG were to construct a pipeline to the existing ADM CO_2 injection well that is approximately 30 miles away. According to IOGCC-SSEB, the needed diameter of the pipeline in order to transport the 2,510,321 tpy of CO_2 captured is between 8-12." Assuming the larger end of the range (12"), which could accommodate up to 3,250,000 tpy of CO_2, and using the upper bound of the cost cited above at $93,750/in. diameter/mile, the total cost would be $33.7 million — an amount which is perfectly within the realm of the reasonable for a plant like this. A pipeline of this nature would raise the cost per ton of CCS to $1.71 per metric ton.

[298] It is unclear whether Schlumberger included the cost of CO2 compression. Thus, to be conservative, I estimated it, assuming two 50% capacity 8-stage integrally geared centrifugal compressors driven by 19,500 hp electric motors and a busbar electricity cost of $50/MWh.

[299] MIT, *Future of Coal in a Carbon Constrained* World 2007 at 58-59, *available at* http://web.mit.edu/coal/ (Commenter's Exhibit 69).

Revenue Code Section 45Q and a reduction in CO_2 compression requirements to 1,900 pounds per square inch after approximately the first five years of injection."[300]

Although there currently is no generally agreed cost threshold for CO_2 BACT cost effectiveness, as discussed above, the cost of CCS for the TEC is at the very low end of the $3-$150/ton range referenced in the GHG BACT analysis in the application (based in turn on the Clean Air Act Advisory Committee ("CAAAC") Climate Change Workgroup Phase I Report). Application v.3 at 6-34. By the same token, it will likely be below even the current depressed price of carbon credits on the European market (approximately $10 per tonne in December 2011).[301] This figure is not, of course, an appropriate benchmark for BACT cost effectiveness, but rather represents a low-bound estimate of the value of carbon reduction on the open market in a recession economy. In the BACT context, given that the structure and purpose of the CAA requires that source developers shoulder a reasonable cost for implementing the best technology, above and beyond what the market would compel, CCG should be assumed capable and responsible to pay significantly more than that for purposes of a Step 4 cost effectiveness determination.

CCS through geologic sequestration in the Mt. Simon formation or CO_2-EOR in Gulf Coast oilfields to control GHG emissions from the AGR vent was eliminated on the basis of availability and technical infeasibility in Step 2 of the GHG BACT analysis and not on the basis of cost effectiveness in Step 4. Despite the clear indication in Section 6.1.1.4 of the Application that the GHG BACT analysis for the AGR vent did not include a control cost analysis for CCS, this comment claim's that IEPA indirectly considered cost- effectiveness in the discussion of EOR on page 31 of the Project Summary. The only sentences referencing costs on this page of the Project Summary are provided below:

> **Other than a few small-scale pilot projects, Illinois oil producers have no experience with conducting EOR at oil fields in the Illinois Basin. EOR has not been deployed commercially in Illinois oil fields because the existing EOR practices cannot produce higher oil recovery rates in an economical manner.32 The closest existing CO_2 pipeline to the proposed plant is located approximately 400 miles away in Mississippi (where EOR can be used to produce higher oil yields at a reasonable cost).**

The references to cost in these statements address the lack of available CO_2-EOR sites in Illinois and not the costs of constructing a pipeline to the Gulf Coast as this comment suggests. CCS using CO_2-EOR in the Gulf Coast was eliminated in the GHG BACT analysis for the AGR vent, since no CO_2 pipeline exists today and CCG has no ability to control CO_2 capture projects in Illinois or adjacent states that may make such a pipeline viable in the future.

While CCG does not disagree with the IEPA's determination that CCS is not a technically feasible control option for reducing GHG emissions from the AGR vent and may be "eliminated at Step 2," CCG nonetheless prepared control cost calculations for

[300] Facility Cost Report, at 81.
[301] *See* http://www.pointcarbon.com/ (last accessed December 28, 2011) (providing daily carbon credit market reports).

geologic sequestration in the Mt. Simon formation and CO_2-EOR in the Gulf Coast to provide information on the true costs of implementing these control measures at the TEC. This comment has made several errors in its CCS cost calculations which result in significant underestimates for the cost of implementation of CCS at the TEC. CCG has corrected these errors in the site-specific CCS control cost analyses discussed below. The control costs calculated with correct data inputs are significantly higher than the values presented by this comment.

This comment begin its CCS cost analysis by claiming the added cost to the TEC for developing the plant to be fully "capture-ready" should not be counted in the analysis. As discussed in the sections of the Application that provide the definition of the project (refer to Section 5.2 of Volume 1 and Section 5.2 of Volume 3), CCG's primary business purpose for the TEC is to meet the requirements of the CCPSL. The only configuration for the TEC to achieve the requirement of the CCPSL to capture at least 50% of the facility-wide CO_2 emissions that would otherwise be emitted is to install a CO shift unit and a two-stage AGR unit with CO_2 separation capabilities. Once syngas is shifted to increase its CO_2 content for downstream removal in the AGR unit, the only available technologies for using this shifted syngas as a fuel in a combined cycle power block are: 1) to shift the syngas to an approximately 3:1 hydrogen to carbon monoxide ratio and to install a methanation unit and a conventional natural gas-fired combustion turbine, or 2) to shift the syngas to generate as much hydrogen as the chemical equilibrium conditions of the shift reaction will allow and to install a high-hydrogen syngas-fired turbine. To meet the CCPSL emissions profile requirement (i.e., having an air emissions profile that is similar to a natural gas combined cycle power plant) and to ensure high availability and reliability of the power block by making it fuel flexible, the coal-to-SNG process configuration is preferable. While it requires a methanation unit, conventional and proven gas-fired combustion turbines capable of using pipeline-quality natural gas or SNG as fuel, can be used in the power block. Methanation of syngas produced from coal gasification is the only commercially available coal-to-SNG process, so the methanation unit is a required element of the TEC in order to satisfy the requirements of the CCPSL. The coal-to-SNG process configuration selected for the TEC is also favored from a project financing standpoint in that natural gas-fired combustion turbines are commercially proven whereas combustion turbines fired with high hydrogen content syngas are not (refer to Section 7.1.2.2 of Volume 3 to the Application). The shift unit, expanded AGR unit, and methanation unit were all added as part of the design changes to comply with the CCPSL, and would not be present at the TEC if CCG had chosen to keep the syngas-fired IGCC plant configuration covered in the prior January 2009 construction permit. Under the previous configuration of the plant, CCG would not have been able to meet the CCS requirements of the CCPSL because 50% of the CO_2 emitted from the plant would not have been available to be captured.

Accordingly the cost of the added elements of the TEC to make the plant capable of implementing CCS as required by the CCPSL, i.e., the costs of a shift unit, expanded AGR unit, and methanation unit, should all be included in the CCS cost analysis. As shown in the following cost analysis tables for geologic sequestration in the Mt. Simon formation, the direct capital costs of installing the shift unit, larger AGR unit with CO_2

separation capabilities, and methanation unit are $339 million ($27.4 million/year on an annualized basis using a capital recovery factor of 0.081 (based on 7% interest over the 30 year life of the plant). The operating and maintenance (O&M) costs for the shift unit, larger AGR unit, and methanation unit are $7.7 million, which gives a total annualized capture costs of $35.1 million. Omitting the largest component to the overall CCS system costs is a fundamental error in the cost analysis presented in this comment.

For geologic sequestration in the Mt. Simon formation, CCG next evaluated the cost of compression equipment to increase the pressure at the AGR vent from ambient pressure to 2,100 psia. The compression equipment total capital investment of $40.1 million developed by CCG's engineering contractor includes costs for excavation, structural supports (i.e., concrete pads, steel beams, etc.), two 12.6 MW electric compressors, piping, electrical and instrumentation, construction, and other indirect costs. The operating costs for the compression equipment of $8.8 million were also developed by CCG's engineering contractor and includes cost for operating and maintenance labor and maintenance parts. These costs do reflect a relatively high percentage of the total capital investment (22%), but these costs are reasonable considering that the compression equipment will be one of the most critical components of the CCS system. Without the compressors, CO_2 from the AGR vent cannot be injected into the Mt. Simon formation. The final component of the compression system cost is the cost for electricity to power the compressors. The total power requirement for the compressors is 25.1 MW and the average power price during the life of the TEC is $107/MWh, which gives annual power costs of $23.6 million.

The comment incorrectly assumes that compression costs will be reduced by the high pressure CO_2 that is produced by the gasification block. The AGR vent is routed from the CO_2 regeneration section of the AGR unit to the compressors at nearly ambient pressure (i.e., less than 1 psig). The statements in CCG's Class VI UIC Injection Well Permit Application regarding compression of the AGR vent "within the power plant" and delivering this compressed CO_2 to the injection field without the need for additional compression equipment at the injection site (Commenter's Exhibit 58 page 95) does not indicate the AGR vent is produced at high pressure. The Class VI permit application is simply highlighting the presence of compression equipment within the fenceline of the TEC and not at the injection site or along the pipeline from the TEC to the injection site.

The commenter attempts to quantify compression cost as part of its analysis, but it uses an undocumented power price of $50 MWh which is less than half of the forecasted power price over the life of the TEC. In addition, confusion is expressed about whether the Schlumberger cost report included compression costs (Commenter's Exhibit 54) when the report does not make any mention of compression.[302]

The final component of the cost analysis for geologic sequestration prepared by CCG is

[302] **Without references to compression in the entire cost study, it is clear that the Schlumberger estimates for costs for geologic sequestration in the Mt. Simon formation do not include the costs for compression equipment and electricity to power the compressors.**

the cost for the injection wells. CCG used the same underlying cost data from the Schlumberger cost study in Commenter's Exhibit 54. The total direct capital costs for the pipeline and injection equipment is $62.3 million, including engineering, land procurement, pipeline equipment and installation, injection well drilling, monitoring well drilling, well head equipment, well testing, and a contingency (refer to Table C-3 of Commenter's Exhibit 54). Indirect costs for the injection system include development (i.e., site characterization/permitting and land options) and well decommissioning. The total capital cost for the injection system is $93.7 million, or an annualized cost of $7.6 million. The total operating costs for the injection system over the life of the plant is approximately $23 million or $766,606 per year.

The commenter's cost calculations for geologic sequestration based on the data in the Schlumberger cost study (refer to Commenter's Exhibit 137) include several errors. First, the total capital investment includes costs that should not be annualized using the capital recovery factor including cost for 1) well work oversight, which Schlumberger included in total operating costs, and 2) other operating costs which should clearly be included in the annual operating costs and not in the total capital investment. In addition, the O&M costs that were considered direct annual costs (i.e., $12,000 for monitor O&M and $112,000 for total O&M) represent the O&M costs only from the first year of operation and not over the lifetime of the source. Finally, the total O&M is inclusive of the monitoring O&M, so these costs should not both be included in the analysis.

After presenting injection system cost calculations based on the Schlumberger cost study, this comment then claims that the calculated costs would be lower: 1) if site characterization information from the ADM Decatur injection site were used rather than collecting site-specific information for the proposed injection site for the TEC, and 2) if less expensive seismic imaging techniques than 4-D imaging were used to evaluate the extent of the subsurface CO_2 plume. Neither of these approaches for reducing costs of the injection system is reasonable, given the dearth of knowledge about the suitability of the Mt. Simon formation for large-scale CO2 sequestration.[303] The comment also claims that CCG has backup plans to proceed with a CO_2 storage

---

[303] **As discussed elsewhere, the Class VI rules require sources to conduct independent site characterization for each injection well, so the ADM Decatur data could not be used the reduce the cost of site characterization for TEC's injection system. Likewise, it would be unsound practice to use less expensive imaging techniques. According to the USDOE NETL, three-dimensional (3-D) seismic surveys are used widely in oil and gas exploration to obtain a three-dimensional view of the subsurface. Dynamite or vibrating machines located at the surface are used to generate downward propagating elastic waves that are reflected from subsurface features and returned to the surface where they are recorded by ground motion sensors. A two-dimensional grid of surface sources and sensors are deployed to obtain a view of the subsurface across the extent of the subsurface feature being evaluated (i.e., the sequestered CO_2 plume for the TEC). 4-D monitoring refers to the process of conducting multiple 3-D surveys over time to assess subsurface changes in real-time. (USDOE NETL, Monitoring Verification and Accounting of CO_2 Stored in Deep Geologic Formations, January 2009, available at http://www.netl.doe.gov/technologies/carbon_seq/refshelf/MVA_Document.pdf.)**

As discussed in the Schlumberger cost study (Commenters' Exhibit 54), 3-D/4-D seismic monitoring will be conducted over a 60 square mile area using receiver lines spaced at 0.25 mile intervals and signal/source lines placed at 0.5 mile intervals. At a cost of $110,115 per square mile for each 3-D/4-D survey, the total costs of each survey event will be $6.6 million. These surveys must be conducted five times over the life of the source for a total cost of $33.0 million. Schlumberger specifically identifies opportunities to minimize the duration and spatial extent of the seismic surveys when they state: "Optimization strategies will be considered during the design of each event. Consideration will be given to timing of the survey (e.g. after crop harvest) and to source and receiver line spacing. Either of these may be reduced either based on site characteristics or advances in technology. The size of the survey area may also be revised. In particular, the area may be reduced for Year 10 and Year 20 where the CO_2 is at an interim position and has not reached its maximum extent." Schlumberger Cost Report,, pg. 11

Without an industry standard or typical suite of technologies that may be applied to seismic monitoring of an injection well for geologic sequestration of CO_2, budgeting for site monitoring requirements is subject to considerable uncertainties. Schlumberger accounted for these uncertainties in a reasonable manner by using the largest surface extent that the CO_2 plume area is expected to occupy in the subsurface.

field in the immediate vicinity of the TEC that is closer than the proposed injection field covered in the Class VI injection well application. This is a misreading of the information in the Facility Cost Report. CCG's statement regarding a backup plan to the Denbury EOR pipeline is actually referring to the injection site addressed in the Schlumberger studies and the Class VI injection well application and not an injection site at an alternate and closer location as the comment suggests.

The commenter presents its own CO_2 pipeline cost estimate based on a pipeline from the TEC to the ADM Decatur injection site 30 miles away. The unit pipeline costs used in the cost estimate of $93,750/inch diameter/mile is taken from Table 2 of Exhibit 68. As needed to accommodate all of the CO_2 produced at the AGR vent, a 12 inch diameter pipeline is assumed, with calculated total costs of $33.7 million or approximately $1.1 million per mile. Schlumberger's estimate for the pipeline from the TEC to the proposed injection wells north of the facility is approximately $1.5 million per mile, which compares favorably with the commenter's cost estimate. However, commenter's use of a 30 mile pipeline distance to the ADM site is not appropriate. This is because the ADM sequestration site is not of an adequate size to store all of the CO_2 produced by the AGR vent, as already discussed.

The commenter presents a total annualized control cost for sequestration in the Mt. Simon formation of $8.82 per ton CO_2, claiming that this cost is "eminently cost effective." This value cannot be reproduced based on the information in Commenter's Exhibit 137 or the electricity cost for compression presented in the comment.[304] Without the ability to recreate the commenter's annual control cost based on the information provided, it is not possible to further verify the accuracy of assumptions or cost components included in the calculations. Regardless, the comment incorrectly excludes the capital and O&M costs for compression equipment ($12.0 million annually) and the capital and O&M costs for the shift unit, expanded AGR unit, and methanation unit ($35 million annually). The true costs of installing, operating, and maintaining a CCS system to store CO_2 in the Mt. Simon formation is $31.49 per ton CO_2 (or more than 3.5 times higher than the cost calculated by this commenter). Even if costs for capture are not included, the cost is $17.52 per ton CO_2.[305, 306]

[304] **As discussed previously, the $4.58 per ton of CO_2 removed cost figure for the injection system presented in that document is flawed because it inappropriately applies the capital recovery factor to O&M costs. The difference between the costs for the injection system in Commenter's Exhibit 137 and the total cost for CCS in the Mt. Simon formation (i.e., $8.82/ton - $4.58/ton = $4.24/ton) does not equal the annual electricity costs for the two 19,500 hp compressors described in the comment. At $50/MWh, two 19,500 hp (14.54 MW) compressors would consume 254,740 MWh of electricity on an annual basis for a total annual electricity cost of $12.7 million. Using the annual potential CO_2 emission rate from the AGR vent presented in Exhibit 137, these electricity costs equate to $5.07 per ton of CO_2 sequestered.**

[305] **CCG's Estimate of Capital and Annual Operating Costs for Geologic Sequestration in the Mt. Simon formation**

Capital Costs for CCS in Mt. Simon to Control GHG Emissions from the AGR Vent including Capture Costs

Capital Cost Summary		Capital Cost for CCS w/ Mt. Simon
DIRECT COSTS		
Compression Equipment[a]		$40,091,787
Shift Unit Capital Cost[b]		$63,745,222
AGR Unit Capital Cost[b]		$115,889,069
Methanation Unit Capital Costs[b]		$160,002,862
Pipeline and Injection Equipment[c]		$62,346,349
TOTAL DIRECT COST (DC)	**DC =**	**$442,075,289**
INDIRECT COSTS		
Development of Mt. Simon Injection Field[d]		$1,100,000
Decommissioning of Mt. Simon Injection Field[e]		$30,273,140
TOTAL INDIRECT COST (IC)	**IC =**	**$31,373,140**
TOTAL CAPITAL INVESTMENT (TCI = DC + IC)	**TCI =**	**$473,448,429**

Annual Costs for CCS in Mt. Simon to Control GHG Emissions from the AGR Vent including Capture Costs

Annual Cost Summary		Annual Cost for CCS w/ Mt. Simon
DIRECT ANNUAL COSTS		
Operating and Maintenance Costs		
Total O&M Costs for Mt. Simon Injection over Lifetime of TEC[f]		$22,998,190
Anticipated Lifetime of the TEC (years)[g]		30
Annual Average O&M Costs for Mt. Simon Injection		$766,606
Shift Unit O&M Costs[b]		$2,696,048
AGR Unit O&M Costs[b]		$1,317,000
Methanation Unit O&M Costs[b]		$3,697,885
Compression Equipment O&M Costs[h]		$8,800,000
Energy Costs for Compression		
Electricity Requirement for Compression (MW)[i]		25.11
Forecasted Average Market Price for Electricity over Lifetime of TEC ($/MWh)[j]		$107
Electricity Cost for Compression		$23,619,069
TOTAL DIRECT ANNUAL COSTS (DAC)	**DAC =**	**$40,896,608**
INDIRECT OPERATING COSTS		
Capital Recovery (CRF x TCI)		
30 years @ 7.00% interest CRF = 0.0806		$38,153,506
TOTAL INDIRECT ANNUAL COSTS (IAC)	**IAC =**	**$38,153,506**
TOTAL ANNUALIZED COST (TAC = DAC + IAC)	**TAC=**	**$79,050,114**

[306] CCG's Cost Effectiveness Calculation for Geologic Sequestration in the Mt. Simon formation

The comment claims that the costs of implementing CCS should be offset by the 45Q IRS tax credits identified in the Facility Cost Report. Based on USEPA guidance, CCG appropriately excluded the 45Q tax credits from the CCS cost analysis. USEPA's Control Cost Manual states the following with respect to income tax credits:

> **Capital is depreciable, indicating that, as the capital is used, it wears out and that lost value cannot be recovered. Depreciation costs are a variable or semi-variable cost that is also included in the calculation of tax credits (if any) and depreciation allowances, whenever taxes are considered in a cost analysis. (However, taxes are not uniformly applied, and subsidies, tax moratoriums, and deferred tax opportunities distort how the direct application of a tax works. Therefore, this Manual methodology does not consider income taxes.)**

Cost Effectiveness Summary

Annual Control Cost:	**$79,050,114**
CO_2 Removed (tpy)[k]:	**2,510,321**
Average Control Cost ($/ton)	**$31.49**

[a] Installed capital costs for compression equipment were developed by CCG's engineering contractor and include cost estimates for excavation, structural supports (i.e., concrete pads, steel beams, etc.), 2 compressors, piping, electrical and instrumentation, construction, and other indirect costs.

[b] CCG's decision to produce SNG is tied to the CCPSL requirement to design the facility to be capable of sequestering at least 50 percent of total CO_2 emissions. Therefore, the capital and O&M costs can be included in the CCS cost analysis for the shift unit, portions of the AGR unit, and the methanation unit, which were added to the design based on the switch from a syngas-fired to a SNG-fired power block. These costs were developed by CCG's engineering contractor.

[c] Total capital costs for the CO_2 pipeline to the injection well sites, well drilling, well testing, and land acquisition from Table C-3 of Exhibit 13.2.b to the Facility Cost Report (FCR) entitled *Schlumberger Carbon Services Cost Report for the Taylorville Energy Center*, available at http://www.icc.illinois.gov/electricity/tenaska.aspx.

[d] Mt. Simon CCS project development cost from Table C-3 of Exhibit 13.2.b to the FCR for site characterization, land options, and permitting.

[e] Decommissioning cost from Table C-3 of Exhibit 13.2.b to the FCR.

[f] Total O&M costs from Table C-3 of Exhibit 13.2.b to the FCR.

[g] Facility lifetime assumed for the cost calculations performed by Schlumberger in Exhibit 13.2.b of the FCR is 30 years (i.e., from 2013 to 2043).

[h] O&M costs for compression equipment were developed by CCG's engineering contractor and include operating and maintenance labor and maintenance parts.

[i] Compressor parasitic load estimated by CCG's engineering contractor.

[j] Average real total retail price of electricity forecasted for the project by Pace Global Energy Services over the facility's lifetime.

[k] Annual potential CO_2 emissions from the AGR vent in Table 3-3 of Volume 3 to the Application.

Cost Effectiveness Summary

Annual Control Cost:	**$79,050,114**
CO_2 Removed (tpy)[k]:	**2,510,321**
Average Control Cost ($/ton)	**$31.49**

[a] Installed capital costs for compression equipment were developed by CCG's engineering contractor and include cost estimates for excavation, structural supports (i.e., concrete pads, steel beams, etc.), 2 compressors, piping, electrical and instrumentation, construction, and other indirect costs.

[b] CCG's decision to produce SNG is tied to the CCPSL requirement to design the facility to be capable of sequestering at least 50 percent of total CO_2 emissions. Therefore, the capital and O&M costs can be included in the CCS cost analysis for the shift unit, portions of the AGR unit, and the methanation unit, which were added to the design based on the switch from a syngas-fired to a SNG-fired power block. These costs were developed by CCG's engineering contractor.

[c] Total capital costs for the CO_2 pipeline to the injection well sites, well drilling, well testing, and land acquisition from Table C-3 of Exhibit 13.2.b to the Facility Cost Report (FCR) entitled *Schlumberger Carbon Services Cost Report for the Taylorville Energy Center*, available at http://www.icc.illinois.gov/electricity/tenaska.aspx.

[d] Mt. Simon CCS project development cost from Table C-3 of Exhibit 13.2.b to the FCR for site characterization, land options, and permitting.

[e] Decommissioning cost from Table C-3 of Exhibit 13.2.b to the FCR.

[f] Total O&M costs from Table C-3 of Exhibit 13.2.b to the FCR.

[g] Facility lifetime assumed for the cost calculations performed by Schlumberger in Exhibit 13.2.b of the FCR is 30 years (i.e., from 2013 to 2043).

[h] O&M costs for compression equipment were developed by CCG's engineering contractor and include operating and maintenance labor and maintenance parts.

[i] Compressor parasitic load estimated by CCG's engineering contractor.

[j] Average real total retail price of electricity forecasted for the project by Pace Global Energy Services over the facility's lifetime.

[k] Annual potential CO_2 emissions from the AGR vent in Table 3-3 of Volume 3 to the Application.

The comment also claims that the cost of CCS could be offset by EOR revenues, but it does not provide a cost analysis specifically for CO_2-EOR in which these revenues could be considered. CCG has prepared a detailed cost evaluation for constructing and operating a CO_2 pipeline for EOR in the Gulf Coast based on the pipeline cost information presented by this commenter ($93,750/in. diameter/mile, refer to Table 2 of Commenter's Exhibit 68). Since the Denbury CO_2 pipeline does not exist today, CCG based the EOR cost calculation on a 350 mile pipeline from the TEC to the closest interconnection point on an existing CO_2 pipeline used for EOR (i.e., the CO_2 pipeline in Mississippi used for EOR in Louisiana oilfields). The annual control cost of implementing CO_2-EOR at the TEC is $36.57 per ton CO_2, and without capture, the cost is $22.59 per ton of CO_2.[307, 308]

[307] **CCG's Estimates of Costs for Geologic Sequestration with EOR**

Capital Costs for CCS using EOR to Control GHG Emissions from the AGR Vent including Capture Costs

Capital Cost Summary		Capital Cost for CCS w/ EOR
DIRECT COSTS		
Compression Equipment[a]		$40,091,787
Unit Pipeline Costs ($/in. diameter-mile)[b]		$93,750
Pipeline Distance (miles)[c]		350
Pipeline Diameter (in.)[d]		12
Total Pipeline Costs		$393,750,000
Shift Unit Capital Cost[e]		$63,745,222
AGR Unit Capital Cost[e]		$115,889,069
Methanation Unit Capital Costs[e]		$160,002,862
TOTAL DIRECT COST (DC)	**DC =**	**$773,478,940**
TOTAL INDIRECT COST (IC)	**IC =**	**$0**
TOTAL CAPITAL INVESTMENT (TCI = DC + IC)	**TCI =**	**$773,478,940**

Annual Costs for CCS using EOR to Control GHG Emissions from the AGR Vent including Capture Costs

Annual Cost Summary		Annual Cost for CCS w/ EOR
DIRECT ANNUAL COSTS		
Operating and Maintenance Costs		
Shift Unit O&M Costs[e]		$2,696,048
AGR Unit O&M Costs[e]		$1,317,000
Methanation Unit O&M Costs[e]		$3,697,885
Compression Equipment O&M Costs[f]		$8,800,000
Revenue from CO_2 Sales		
CO_2 Commodity Revenue per Ton ($/ton CO_2)[g]		-$4.25
Annual Potential CO_2 Emissions Available for CCS at 100% Capture (tpy)[h]		2,510,321
CO_2 Commodity Revenue		-$10,670,483
Energy Costs for Compression		
Electricity Requirement for Compression (MW)[i]		25.11
Forecasted Average Market Price for Electricity over Lifetime of TEC ($/MWh)[j]		$107
Electricity Cost for Compression		$23,619,069
TOTAL DIRECT ANNUAL COSTS (DAC)	**DAC =**	**$29,459,519**
INDIRECT OPERATING COSTS		
Capital Recovery (CRF x TCI)		
30 years @[k] 7.00% interest CRF = 0.0806		$62,331,886
TOTAL INDIRECT ANNUAL COSTS (IAC)	**IAC =**	**$62,331,886**
TOTAL ANNUALIZED COST (TAC = DAC + IAC)	**TAC=**	**$91,791,405**

[308] CCG's Cost-Effectiveness Calculations for Geologic **Sequestration with EOR**

Cost Effectiveness Summary

Annual Control Cost:	**$91,791,405**
CO_2 Removed (tpy)[f]:	**2,510,321**
Average Control Cost ($/ton)	**$36.57**

[a] Installed capital costs for compression equipment were developed by CCG's engineering contractor and include cost estimates for excavation, structural supports (i.e., concrete pads, steel beams, etc.), 2 compressors, piping, electrical and instrumentation, construction, and other indirect costs.

[b] Commenters Exhibit 68 Table 2 for Green Pipeline. This pipeline cost was referenced by Commenters in footnote 220 and was used in their annual control cost calculations for CCS.

[c] Approximate distance from the TEC to the closest interconnection point to an existing EOR pipeline in Mississippi.

[d] A 12 in. CO_2 pipeline can transport between 1.13 and 3.25 MMtpy of CO_2 and can accommodate the 2.51 MMtpy of CO_2 on an annual potential basis from the AGR vent.

[e] CCG's decision to produce SNG is tied to the CCPSL requirement to design the facility to be capable of sequestering at least 50 percent of total CO_2 emissions. Therefore, the capital and O&M costs can be included in the CCS cost analysis for the shift unit, portions of the AGR unit, and the methanation unit, which were added to the design based on the switch from a syngas-fired to a SNG-fired power block. These costs were developed by CCG's engineering contractor.

[f] O&M costs for compression equipment were developed by CCG's engineering contractor and include operating and maintenance labor and maintenance parts.

[g] Calculated based on the annual EOR revenue ($8.9 million) and mass of CO_2 sequestered annually by EOR (1.9 million metric ton/yr or 2.09 million short tons/yr) from Section 10.1.6 of the Facility Cost Report (FCR).

[h] Annual potential CO_2 emissions from the AGR vent in Table 3-3 of Volume 3 to the Application.

[i] Compressor parasitic load estimated by CCG's engineering contractor.

[j] Average real total retail price of electricity forecasted for the project by Pace Global Energy Services over the facility's lifetime.

[k] Facility lifetime assumed for the cost calculations performed by Schlumberger in Exhibit 13.2.b of the FCR is 30 years (i.e., from 2013 to 2043).

Cost Effectiveness Summary

Annual Control Cost:	**$91,791,405**
CO_2 Removed (tpy)[f]:	**2,510,321**
Average Control Cost ($/ton)	**$36.57**

[a] Installed capital costs for compression equipment were developed by CCG's engineering contractor and include cost estimates for excavation, structural supports (i.e., concrete pads, steel beams, etc.), 2 compressors, piping, electrical and instrumentation, construction, and other indirect costs.

[b] Commenters Exhibit 68 Table 2 for Green Pipeline. This pipeline cost was referenced by Commenters in footnote 220 and was used in their annual control cost calculations for CCS.

[c] Approximate distance from the TEC to the closest interconnection point to an existing EOR pipeline in Mississippi.

[d] A 12 in. CO_2 pipeline can transport between 1.13 and 3.25 MMtpy of CO_2 and can accommodate the 2.51 MMtpy of CO_2 on an annual potential basis from the AGR vent.

[e] CCG's decision to produce SNG is tied to the CCPSL requirement to design the facility to be capable of sequestering at least 50 percent of total CO_2 emissions. Therefore, the capital and O&M costs can be included in the CCS cost analysis for the shift unit, portions of the AGR unit, and the methanation unit, which were added to the design based on the switch from a syngas-fired to a SNG-fired power block. These costs were developed by CCG's engineering contractor.

[f] O&M costs for compression equipment were developed by CCG's engineering contractor and include operating and maintenance labor and maintenance parts.

[g] Calculated based on the annual EOR revenue ($8.9 million) and mass of CO_2 sequestered annually by EOR (1.9 million metric ton/yr or 2.09 million short tons/yr) from Section 10.1.6 of the Facility Cost Report (FCR).

[h] Annual potential CO_2 emissions from the AGR vent in Table 3-3 of Volume 3 to the Application.

[i] Compressor parasitic load estimated by CCG's engineering contractor.

[j] Average real total retail price of electricity forecasted for the project by Pace Global Energy Services over the facility's lifetime.

[k] Facility lifetime assumed for the cost calculations performed by Schlumberger in Exhibit 13.2.b of the FCR is 30 years (i.e., from 2013 to 2043).

73. "Adjustable BACT Limits" should be set for emissions of CO_2. CCG objects to CO_2 emission limits at the TEC because it believes that BACT limits are inflexible and cannot address the possibility that sequestration will not immediately be operational when the plant starts operating:

> [CCG] has no certainty about whether or not an AGR vent CO_2 BACT limit based on the use of CCS could be complied with when the TEC becomes operational, so accepting such a limit which carries with it strict penalties up to and including a mandatory facility shutdown is not possible at this time. CCG is, however, committed to meeting the sequestration provisions of CCA which are in no way similar to a strict, not-to-exceed BACT limit, since these provisions provide CCG flexibility in the event that CCS is not available when the plant begins operation. No similar flexibility is permissible under the definition of BACT.
> Application, Vol. 3 at 6-9 & n.22.

However, as described earlier, there is no support in the law for CCG's assertion that BACT limits cannot be adjustable, where a new technology is brought on line for the significant control of an air pollutant. IEPA has the authority to set adjustable emission limits that address the applicant's concern that CO_2 sequestration may not be immediately operational at the future point when the plant commences operations.

In its review of the properly supplemented record for the TEC, IEPA must evaluate two approaches to adjustable CO_2 emission limits. Both approaches must rely on 95 percent capture of the CO_2 from the AGR vent. CCG notes that capture technology is available[309] for the AGR vent and that the project will capture 95 percent of the CO_2 from the AGR vent.[310] Clearly that level of CO_2 reduction is far better than would be the case under the CO_2 BACT limits included in the Draft Permit, the potential uncontrolled CO_2 emissions from the AGR vent would be 2,510,321 tons/year.[311] The total plant CO_2 emissions are 5,031,409 tons per year.[312] The AGR vent CO_2 emissions therefore represent roughly half the plant's total CO_2 emissions – a BACT limit set based on eventual 95 percent reductions of the AGR vent CO_2 emissions, therefore represents approximately half of the CO_2 emissions from the plant, taken as a whole. I offer two options for the establishment of such a standard.

<u>Option A. Establish CO_2 emission limits that adjust downward over time.</u>

IEPA could adjust the CO_2 emission limit downward over a three-year period. In this approach, IEPA could establish emission limits for the TEC that do not require CCS in years one and two of plant operation, but instead basically reflect the CO_2 BACT limits included

[309] Application, Vol. 3 at 6-3. "For the gasification block, separation of formed CO_2 is inherent to the process of producing natural gas pipeline-quality SNG from coal. CO_2 separation from pressurized syngas is a commercially-available proven process in the SNG production and chemicals sector although not in the power generation sector. Capture or separation of the CO_2 stream alone is not a sufficient control technology, but instead requires the additional step of permanent sequestration." *Id.*
[310] ICC Report, Exhibit 2.1 (Project Description) at 9, states "Over 95% of the CO_2 available to AGR in the synthesis gas will be captured." (Available at http://www.icc.illinois.gov/electricity/tenaska.aspx).
[311] Application, Vol. 3 at A-16.
[312] Draft Permit, Table IV.

in the draft permit. Beginning in year three, however, the deeper CCS-based emission limit would become effective, reflecting capture and sequestration of 95 percent of the potential CO_2 emissions of AGR unit. This formulation would provide CCG greater flexibility and enable the completion of permitting for onsite sequestration.

Option B. Establish CO_2 emission limits that reflect CCS at the outset, but provide "worst case" limits in the (unlikely) event that sequestration at the site is not permitted.

IEPA could establish an emission limit applicable from the outset of operations that reflects capture and sequestration of 95 percent of the potential CO_2 emissions of AGR system, but provides a fallback or "worst case" emissions limit that would come into effect in the unlikely event that CCG or its successor (if any) is unable to secure its Class VI permit for sequestration by the TEC.

In this approach, the "worst case" scenario, essentially the BACT limit provided for in the Draft Permit, expressed as a limit for the whole TEC (as an EGU) would allow the TEC to emit CO_2 at a level not reflecting CCS for any period during the first ten years of operation during which no permit is approved for sequestration, either on site or via pipeline to offsite enhanced oil recovery operations.

For either Option, the IEPA would need to establish an appropriate numerical limit for annual CO_2 emissions of AGR Unit. The limit would be easily established based on the information presented by CCG on total potential CO_2 emissions and the proposed level of CO_2 control with CCS contained in the application and other materials relevant to TEC, including the submissions accompanying my comments.

"Adjustable BACT CO_2 BACT Limits," as recommended by this comment, are not appropriate or legally supportable for the TEC. This is because they would not confront the fundamental issue posed for the TEC by CCS, that is, whether CCS is currently technical feasible and can be mandated as BACT. Indeed, the use of adjustable BACT Limits, as proposed by this comment, would only serve to confirm that CCS is not technically feasible at this time.

As compared to the circumstances where adjustable BACT limits have been used, as identified in this comment, a key distinction is that the control technology that would constitute BACT was not at issue, only the emission limit that was achievable with that control technology. Adjustable limits were used to enable emission rates demonstrated in actual operation of emission units to be considered, with the possibility for different BACT emission limits to subsequently be set. As related to carbon sequestration for the TEC, the issue is whether this control technology should even be considered achievable.

In essence, this comment advocates for CCS to be required as BACT because sequestration is expected to become an achievable technology that is proven to be viable and reliable at some future point in time. This does not reflect current law. BACT must be achievable based on existing, demonstrable technology at the time of permit issuance. BACT should not be based on speculation about the future status of a

control technology, even if the permitting authority or others (including the applicant) expect that the technology will eventually be proven.[313]

BACT WAS NOT REQUIRED FOR THE PRESSURE RELIEF VALVES

74. The proposed plant would include pressure relief valves ("PRVs"), which are generally listed with equipment leak component.[314] Except for PRVs in GHG-service, these PRVs would be routed to the flare. The application does not contain a BACT analyses for these PRVs, in either the flare BACT analysis or equipment leak BACT analysis. In the equipment leak section, the application states only that the top technology for control of emissions from PRVs is routing them to an add-on control device, such as an oxidizer or flare.[315] This is simply stated with no support or analysis. Other options were not considered and rejected.

First, the seals on PRVs can leak continuously, sending large constant volumes of gases to the flare. Rupture disks are used to prevent this leakage. Rupture disks are an extra metal seal that prevents leakage through the PRV until it opens. These were not considered in the BACT analysis and are not required by the Draft Permit. Second, PRVs are designed to open when the pressure gets above a certain set point in a vessel. When set point is exceeded, the disk ruptures, and the pressure relief valve opens. When the pressure relief valve later closes after the pressure goes back down, the rupture disk is no longer there, and it no longer provides any protection from leakage. Further, it is known that sometimes PRVs do not re-seat after opening properly, so leakage can occur through the PRV seals. This requires a work practice standard, the immediate replacement of rupture disks after a flare event. This was also not considered in the BACT analysis or required by the Draft Permit. Third, the BACT analysis is silent on control options for PRVs that would not be routed to the flare. No control options at all are advanced. These PRVs should be routed to the AGR vent and subject to BACT level controls there.

Finally, the emission inventory does not include any emissions for PRV releases, except those from the PRVs that are not vented to the flare. This essentially assumes that flaring controls 100% of the PRV emissions. The application should have applied, at best, 98% destruction efficiency, for the times that leakage occurs. The Application should have included an evaluation employing a factor for how often rupture disks open, how fast they get repaired after opening, and included a permit provision to guarantee these assumptions. These emissions should also have been included in the Potential to Emit.

Flare Loss Monitoring, is an example of an industry website that found that small leaks in PRVs routed to flares can cause large annual emissions.[316] The diagram provided shows over 63,000 kg/year (or about 140,000 lbs/year) of leakage to the flare (before combustion) from a single PRV, and talks in general about substantial leakage to flares from PRVs. This document found that although the number of leaks should be small, the individual leak rate can be extremely large, and continuous. This source states:

---

[313] **In this regard, the criteria for BACT is different from that for Best Demonstrated Technology, as must be addressed by USEPA when it adopts New Source Performance Standards (NSPS) pursuant to Section 111(1)(a) of the Clean Air Act.**

[314] Ap., v. 1, Tables C-24 to C-27 and v. 3, Tables A-15 to A-19.

[315] *See, e.g., Ap., v. 1, p.6-42, 6-51. and Draft Permit, Condition 4.9.2.c*

[316] The Sniffers NV/SA, Flare Loss Monitoring, *available at* http ://www.the-sniffers.be/flare/monitoring.htm. (Commenter's Exhibit 70)

> Flare emissions to the atmosphere are losses of VOC's caused by internal leaking equipment such as pressure relief valves, ball & gate valves. These uncontrolled emissions can lead to huge losses. The visible flame at the flare stack, the losses of raw materials, unreliable stream balances and the environmental aspect have created awareness that companies and organizations should work on their Flare emission monitoring programs. By the absence of a thorough monitoring and maintenance program, these emissions are the most significant cause of losses of raw materials resulting from plant activities.

For industrial flares, AP-42 also recognizes that leaking PRVs can be routed to flares:

> At many locations, flares normally used to dispose of low-volume continuous emissions are designed to handle large quantities of waste gases that may be intermittently generated during plant emergencies. Flare gas volumes can vary from a few cubic meters per hour during regular operations up to several thousand cubic meters per hour during major upsets. Flow rates at a refinery could be from 45 to 90 kilograms per hour (kg/hr) (100 - 200 pounds per hour [lb/hr]) for relief valve leakage but could reach a full plant emergency rate of 700 megagrams per hour (Mg/hr) (750 tons/hr).[317]

Although AP-42 refers to petroleum refineries, the PRVs and their connection to the flare are exactly the same as the types that would be present at the TEC. These leakages can result in large emissions over time. In the refinery example provided by AP-42, 100-200 lbs/hour amounts to almost 440 to 880 tons per year routed to the flare, which even at 98% efficiency would result in about 9 to 18 tons per year in added flare emissions. With 115 PRV routed to the flare, this source should have been subject to a rigorous BACT analysis and the emissions included in the emission inventory and air quality modeling.

The comment acknowledges that routing PRVs to a flare is the top control technology, but suggest the TEC application is deficient because confirming PRVs would be routed to a flare was "simply stated with no support or analysis." The comment is correct that add-on control technologies such as oxidizers or flares are the top technically feasible control for PRVs, but inaccurately portrays the BACT analysis for PRVs.

A full top-down BACT analysis for PRVs and equipment leak components was done and reviewed by the IEPA. *See* Section 6.6 of Volume 1 to the Application. Each step was thoroughly documented for each pollutant potentially emitted by PRVs and equipment leak components. Each of the following control options were identified and described as part of Step 1 of the BACT analysis:

- **Routing any fugitive emissions from pressure releases at PRVs to a control device**
- **Utilizing "leakless" components (i.e., welded connectors, bellows valves, double mechanical seals with high pressure barrier fluids on pumps, enclosed distance pieces on compressors with venting to a control device, etc.)**

[317] AP-42 — Chapter 13.5-2, Industrial Flares (Sept. 1991) at 2-3.

- **Various LDAR programs in accordance with applicable state and federal air regulations**
- **Audio/visual/olfactory (AVO) monitoring program for odorous compounds with intensive-directed maintenance**
- **Area organic vapor analyzer (OVA) monitoring program for odorous compounds with intensive-directed maintenance**
- **Good work practices (GWP)**

Leakless components and audio/visual/olfactory (AVO) monitoring were eliminated as technically infeasible control options under Step 2. PRVs are critical safety devices for which "leakless" designs currently are not available in the same way that leakless designs are available for conventional valves.

Under Step 3, CCG ranked the remaining technically feasible control options, identifying routing PRVs to add-on control device such as a flare as the top ranked control for PRVs, over LDAR, area OVA monitoring, and good work practices. As such, CCG committed to selecting the top available control technology for reducing emissions from PRVs by routing all PRVs in CO and VOM service to a flare which will achieve 98% DRE for these compounds. [See Condition 4.1.2-1(a)(v) in the permit for the related requirements for design and operation of the flare.] CCG also performed a full top-down analysis for emissions from the flare under Section 6.1 of the Application, and the hourly and annual BACT limits for CO and VOM set in Condition 4.1.2-1(d)(ii) based on this analysis include any emissions attributable to routing process gas from PRVs to the flare. With PRVs routed to the flare header, any emissions from PRV leaks or releases will be discharged into the flare header and controlled by the flare. No emissions from PRVs routed to the flare header will be discharged directly to the atmosphere as fugitive emissions, but instead will be routed to another emission point for which a separate BACT analysis is conducted. For this reason, TCEQ provides for a 100% control credit for PRVs routed to a control device,[318] since under this configuration, PRVs are eliminated as a direct source of emissions to the atmosphere. The provision for a 100% control credit does not suggest that a 100% control efficiency for PRV leaks or releases will be achieved by the control device, but simply that any emissions from the PRVs should be accounted for at the control device and not as a fugitive equipment leak component.

Notwithstanding, this analysis, the comment asserts that BACT for PRVs is not adequate for a number of reasons: 1) Rupture disks were not considered; 2) A work practice to immediately replace rupture disks after a flare event was not considered; 3) The analysis is silent on control options for the 11 PRVs not routed to the flare, and 4) The emissions inventory does not address PRVs that routed to the flare.

As related to use of rupture disks, they were not considered in the BACT analysis because it would not have changed the BACT determination. Rupture discs aid in leak monitoring for PRVs, signaling when a PRV has experienced a release or gone above a

[318] TCEQ, Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000, Draft. See page 17.

set pressure. The usefulness of rupture discs is primarily limited to PRVs at existing facilities that relief to the atmosphere and are not equipped with any other type of monitoring device to indicate when a leak or release has occurred. The comment does not show that rupture disks act as a control device or would act to directly control emissions. In fact, adding rupture disks to the PRVs routed to the flare header at the TEC would provide no reduction in emissions. Furthermore, even if rupture disks were assumed to have some level of control, rupture disks would not result in a 98% reduction in emissions achieved by routing emissions to a flare.

USEPA and TCEQ consider routing PRVs to a control device and equipping PRVs with a rupture disc and pressure sensing device to be entirely separate practices. Pursuant to 40 CFR 63.165(b) of NESHAP Subpart H (commonly referred to as the HON), USEPA requires PRVs to be returned to a non-emitting condition as indicated by an instrument monitoring reading of less than 500 ppm above background, as soon as practicable after each pressure release to the atmosphere. Follow-up monitoring to ensure the PRV remains seated is required within 5 days after the release [refer to 40 CFR 63.165(b)(2)]. Pursuant to 40 CFR 63.165(c), any PRV that is routed to a process or fuel gas system or equipped with a closed-vent system capable of capturing and transporting leakage from the PRV to a control device is exempt from the instrument monitoring requirements of 40 CFR 63.165(b). Through an entirely separate requirement, USEPA also exempts PRVs equipped with a rupture disk from the requirements of 40 CFR 63.165(a), provided that a rupture disk is installed upstream of the PRV as soon as practicable after each pressure release. USEPA does not require sources to route PRVs to a control device and equip these same PRVs with rupture discs as MACT for organic HAP emissions. In a similar manner, in its permitting guidance for equipment leaks, TCEQ states that "BACT guidelines generally require that all relief valves vent to a control device" for new facilities over the alternative option of equipping PRVs with a rupture disc and pressure sensing device. TCEQ provides for a 100% control credit for rupture discs equipped with a pressure sensing device under their equipment leak guidance not because these systems actually reduce emissions to the atmosphere when a PRV is leaking or releasing, but only because they provide operators with an indication that a PRV leak or release has occurred. USEPA's regulatory scheme for addressing PRV releases and TCEQ's BACT guidance for the top PRV control option at new facilities clearly indicate a general preference to route PRVs to a control device over using a rupture disc and pressure sensing device.

As a separate requirement from the flare flow monitoring provisions in Condition 4.1.8-2(a)(i)(A), Condition 4.1.8-2(a)(i)(C) requires operational monitoring to determine the date, time, and duration of each occurrence of venting process gas to the flare header. Each occurrence of venting process gas would include any emissions from PRVs vented into the flare header. In light of this permit requirement, the comment's suggestion that a PRV could leak and send a large and continuous flow rate of process gas to the flare without CCG's knowledge is unsupported and incorrect. The continuous monitoring system required by Condition 4.1.8-2(a)(i)(C) will be just as effective at identifying PRV leaks and releases as rupture discs equipped with a pressure sensing device. Thus rupture disks would be redundant monitoring systems and did not need to be considered in the BACT analysis.

As to the comment's claims that the permit should require immediate replacement of rupture disks after a flare event, rupture disks are not BACT for the PRVs, as already discussed above. Rather rupture disks would generally be a redundant form of operational monitoring indicators given other continuous monitoring that will be in place to identify PRV leaks and releases. Although CCG plans to implement other more accurate measures for identifying PRV leaks or releases, the permit does address the use of rupture discs and pressure sensing devices in the unlikely event that they are an element of the engineering design for certain PRVs routed to the flare.[319] These relevant permit conditions include the same work practice standard requirements that the comment suggests should be included in the permit.

As to the comment's claims the 11 PRVs not routed to the flare should be routed to the AGR vent and subject to BACT level controls, the BACT analysis is not "silent" on control options for these 11 PRVs. The 11 PRVs not routed to the flare are in GHG-only service. As such they are addressed in the GHG BACT analysis in Volume 3 of the Application. In Volume 3, CCG expanded upon the BACT approach applied to CO and VOM emissions from PRVs in Volume 1 of the Application. In the GHG BACT analysis, CCG again identified all available control technologies, consistent with the list delineated previously. However, for the 11 PRVs in GHG-only service, routing emissions to an add-on control device such as an oxidizer or flare was eliminated as a technically infeasible CO_2 option because GHG emissions would not be effectively controlled. CCS was eliminated as technically infeasible, as will be discussed in response to other comments.

Of the expected 11 PRVs that are not routed to the flare, two are in compressed CO_2 service for use in steam turbine maintenance and nine are in natural gas service for supplying fuel to the combustion turbines. For the PRVs in CO_2 service routing emissions to a flare would not provide any additional control, so this option was appropriately excluded from the GHG BACT analysis for ELC.

For the PRVs in natural gas service, the potential methane emissions are 9.04 tpy and 189.8 tpy on a CO_2e basis. At this low uncontrolled emission rate, routing PRV emissions to the flare would not be practical or cost effective. To route the emissions from these PRVs to the flare, CCG would have to install a complex network of piping which would include additional equipment leak components in methane service (such as additional flanged connectors for joining the necessary pipe segments for the new flare header piping). Each individual PRV would have to have its own dedicated pipeline to the flare header because they are likely to be spaced large distances apart. The approximate distance from the center of the power block to the closest anticipated location of the flare header is approximately 600 feet. Based on this distance, the combined piping distance for each of the 9 PRVs would be at least 5,400 feet. Section 3.2 Chapter 1 of USEPA's *Air Pollution Control Cost Manual* (6th edition) provides a methodology for estimating the annualized control cost of installing transport piping to

[319] **Where rupture discs are implemented at the CCG's discretion, Condition 4.9.6(c) requires a pressure-sensing device to be installed between the PRV and the rupture disc to monitor disc integrity and requires all leaking discs to be replaced at the earliest opportunity but no later than the next process shutdown. In instances where the pressure reading of a pressure sensing device is not continuously monitored and recorded, Condition 4.9.6(d), requires a check of the reading of the pressure-sensing device to verify disc integrity on a weekly basis.**

route process gas to a flare header.[320] CCG developed an analysis based on the default assumptions in this guidance manual to determine the annualized control cost of routing these natural gas PRVs to the flare header. CCG would have to incur costs of $6,880 per year to reduce emissions from natural gas PRVs by 163.6 tpy CO_2e, which translates to an annualized control cost of $42/ton removed, as CO_2e. The IEPA considers this cost to be excessive for control of these GHG emissions,[321] independent of other possible adverse impacts.[322] The cost for routing PRV emissions from natural gas piping to the flare would be more than two times higher.

As already discussed, rupture discs are not a BACT control option but are simply a means to identify PRV leaks and releases. CCG must continuously measure the pressure and flow rate of natural gas in the fuel lines serving the combustion turbines as the fuel gas pressure and flow rate are critical operating parameters for ensuring the proper operation of the combustion turbines [Condition 4.2.9-2(a)]. By measuring these parameters, CCG would be immediately aware of any natural gas piping PRV leaks or releases and would implement the appropriate corrective action to ensure the PRV venting episode was remedied as soon as practicable to avoid impacting the operation of the combustion turbines.

As related to this comment's assertion that the application's emissions inventory does not include any emissions for PRV releases, except those from the PRVs that are not vented to the flare, CCG specifically addressed potential emissions from the flare in Section C-3 of Appendix C to Volume 1 of the Application. These potential emissions calculations estimated maximum hourly and per event off-specification process gas flow rates and compositions expected to be routed to the flare during cold plant startups, total plant shutdowns, and single gasifier startups and shutdowns. These process gases will be routed to the flare header through control valves identified as PRVs in the component counts. Although CCG did not quantify malfunction emissions in the application for reasons that have already been discussed, the flare BACT limits in Condition 4.1.2-1(d)(ii) apply at all times. To demonstrate compliance with these BACT limits, CCG is required to maintain records of the date, time, duration, and emissions for each flaring episode including any emissions resulting from PRVs routed to the flare that occurs during a malfunction [Condition 4.1.10-2(b)]. Therefore, the flare BACT limits include all emissions that could be due to PRVs routed to the flare header. In this regard, the comment incorrectly indicated that flaring was assumed to control 100% of PRV emissions. CCG appropriately applied a

---

[320] **USEPA, Air Pollution Control Cost Manual - Sixth Edition (EPA 452/B-02-001), Section 3 VOC Control, Section 3.2 VOC Destruction Controls, Chapter 1 – Flares, September 2000, available at http://www.epa.gov/ttn/catc/products.html.**

[321] **For example, in the Responsiveness Summary for Universal Cement, IEPA referred to a cost threshold for GHG controls of $20/ton. IEPA, Responsiveness Summary for Public Questions and Comments on the Construction Permit Application for Universal Cement, LLC for a Portland Cement Manufacturing Plant in Chicago, Illinois, December 2011.**

[322] **Beyond the adverse economic impacts from routing natural gas PRVs to the flare, this GHG control measure would pose adverse environmental impacts from increasing criteria pollutant emissions from the flare. To accommodate the additional piping required to route the PRV emissions to the flare, CCG would have to increase the purge gas flow rate to the flare header. Additional purge gas flow could require larger flare pilots and more supplemental natural gas flow to the flare to ensure compliance with Condition 4.1.2-1(b)(vi) of the Draft Permit. Higher process gas, purge gas, pilot gas, and supplemental fuel gas flow rates to the flare would cause an increase in CO, NOx, and VOM emissions from the flare that would offset the environmental benefit of reducing GHG emissions by only 163.6 tpy CO_2e (i.e., less than 0.25% of the GHG major modification threshold** and less **than 0.2% of the major source threshold). Therefore, routing natural gas PRV emissions to the flare can be readily eliminated as a BACT control option on the basis of adverse economic and environmental impacts.**

98% flare DRE for control of CO and VOM emission found in the off-specification process gas that will be routed to the flare from PRVs. In addition, Condition 4.1.8-2 of the Draft Permit requires CCG to monitor: 1) the total flow rate of process gas sent to the flare on a continuous basis, 2) the CO content of the process gas sent to the flare on a continuous basis, and 3) the date, time, and duration of each occurrence of venting of process gas to the flare. In conjunction with VOM composition estimates derived from the periodic sampling required by Condition 4.1.9(b), the flare monitoring requirements in the permit will ensure that CCG can generate accurate emission data for all process gas flaring that occurs at the TEC, as required by Condition 4.1.10-2(b) including any emissions that are attributable to PRV leaks or releases.

The comment also suggests PRVs contribute to significant potential emissions based on the printed webpage the comment refers to as *Flare Loss Monitoring*. This is not a cited reference to a peer-reviewed study, or even literature, but only to a company's marketing webpage for their services. The comment refers to this webpage to suggest that a single PRV can leak 140,000 lbs/year. The webpage referenced by the comment presents a diagram and emission estimate for an "example of a leak" which cannot be confirmed as a report of emissions measured by USEPA reference methods or more likely a fabricated diagram for marketing purposes. Furthermore, the quoted leak rate is described as a "gate valve" which is not a PRV. This reference is not relevant to the BACT analysis for PRVs.

The final element of the comment's assertion that the BACT analysis was insufficient for PRVs refers to AP-42, Chapter 13.5 "Industrial Flares." The comment cites a quote from AP-42 that notes flares at refineries could see flow rates ranging from 100 – 200 pounds per hour for relief valve leakage. The comment incorrectly states that PRVs and their connection to the flare are exactly the same at a refinery as they will be at TEC. The many differences between the TEC and a refinery have been thoroughly described in responses to other comments, as well as the reasons it is inappropriate to compare refineries to TEC (as discussed elsewhere). The comment and AP-42 do not expand upon the basis for the cited flare loading of 100 – 200 pounds per hour from PRV leakage. Since this statement in AP-42 does not provide a basis for the number of PRVs leaking and the composition of the process streams associated with the leaking PRVs, it cannot be determined if the emission rate referenced is applicable to TEC given the differences between TEC and refineries that were previously noted.

In comparison, the TCEQ emission factor for PRVs for SOCMI without ethylene facilities of 0.2293 lb/hr/source would suggest a potential flow of less than 27 lb/hr from the TEC facility's 115 PRVs routed to the flare – an order of magnitude different than the refinery example utilized by the comment. As such, the comment's assertion that PRV leaks to the flare are equivalent to AP-42's general estimate for refinery flares is inaccurate and inappropriate.

In conclusion, a thorough and appropriate top-down BACT evaluation was conducted for PRVs and accurately estimated emissions to the atmosphere for both the 11 PRVs in GHG-only service as well as the controlled emissions from the flare for the PRVs in CO and VOM service. The BACT determination made by the IEPA for PRVs using

this information is consistent with how PRVs are addressed in USEPA LDAR programs and in permits for other chemical plants.

BACT WAS NOT REQUIRED FOR THE FLARE

75. During normal operation of the gasification block, the only emissions from the gasification block would be from the natural gas fired pilot in the flare, exhaust from the SRU thermal oxidizer and incidental operations, such as storage and handling of sulfur. However, during non-normal conditions, such as startups, shutdowns, and malfunctions, raw and partially treated gases would be vented to the flare.

A major flaw in the BACT analyses is that IEPA failed to evaluate or require the use of cleaner fuels, such as lower sulfur coal or biomass, to reduce emissions of SO_2 and other pollutants during flaring. This use is distinguishable from the use of clean fuels as the feed to the gasifier, as discussed above. Similar gasification projects routinely specify the use of low sulfur coal during planned startup and shutdown events.[323] The BACT analysis for the TEC concluded that the use of low sulfur subbituminous coal is not a technically feasible control option for reducing SO_2 emissions from the flare. The BACT analysis argues that the gasifiers and syngas gas conditioning train are specifically designed for the moisture content, ash content, and heating value of Illinois bituminous coal and the flow rate and composition of syngas the gasifiers produce using this feedstock.[324] However, none of these parameters are reported anywhere in the record or required as permit conditions.

This is incorrect as a technical matter. First, Siemens literature indicates that the subject gasifiers can burn a wide range of feedstocks.[325] Second, the majority of the emissions occur during the period when the raw syngas is sent directly to the flare without any treatment. In other words, it bypasses the syngas gas processing train so that the design basis of this train is irrelevant. Also, the design of the coal handling system is not a constraint in processing a different coal for the short periods of time involved during planned startups and shutdowns. Any critical portion of the material handling system could have a parallel train designed for the alternate fuel. Thus, the BACT analysis must evaluate the use of low sulfur subbituminous and other low sulfur coals during non-routine operation.

Further, even assuming design constraints during portions of non-routine events, I note that there is a wide range of similar Illinois Basin coals with lower sulfur than the design coal assumed in the emission calculations that have similar physical properties.[326] The BACT analysis failed to consider other similar, lower sulfur Illinois Basin coals to reduce SO_2 emissions from flaring during startups, shutdowns, and malfunction. Other gasification projects routinely use a low sulfur coal pile to control non-routine flaring emissions.

The Clean Air Act requires that BACT limits be established based on the emission reductions achievable using cleaner fuels. 42 U.S.C. § 7479(3); 40 CFR 52.21(b)(12). The

[323] *See, e.g.*, West Virginia Department of Environmental Protection, Division of Air Quality, Permit to Construct, TransGas Development Systems, LLC, R13-2791, February 25, 2010, Cond. 4.1.5.5.c, p. 24 ("Coal gasified during start-up shall not contain sulfur in excess of 0.5% by-weight.") ("TransGas Permit"). (Commenter's Exhibit 72)
[324] Ap., v. 1, p. 6-10.
[325] Siemens Fuel Gasifier; http://www.energy.siemens.com/hg/en/power-generation/fuel-gasifier/. (Commenter's Exhibit 73)
[326] *See, e.g.*, USGS Report, *supra* n. 3.

Application, IEPA Project Summary, and Draft Permit, however, all fail to include any evaluation of lower-sulfur coal as part of the BACT analyses for the TEC. As such, the IEPA must require CCG to submit such an evaluation, and can allow the TEC to avoid using lower sulfur coal only if CCG can demonstrate, and the IEPA can independently confirm, that the cost of pollutant removal from using such fuel is "disproportionately high when compared to the cost of control for that particular pollutant and source in recent BACT determinations."[327]

As previously discussed, a BACT evaluation must generally include the consideration of clean fuel alternatives. However, in some circumstances, a clean fuel may warrant elimination as a control option under Step 1 of the Top-Down BACT Process on the basis that its use would effectively redefine the proposed source. In addition to other considerations relating to technical feasibility and cost-effectiveness, this legal construct carries over into the BACT analysis for the flare emissions, as the TEC project and its integral process components have been specifically designed for use of high sulfur bituminous coal.

Notwithstanding these circumstances, CCG included in the Application a BACT evaluation for utilizing low sulfur feedstocks during startup as a means for reducing SO_2 emissions from the flare (refer to Section 6.1.1. of Volume 1 to the Application). Potential control measures evaluated in this portion of the flare SO_2 BACT analysis included both the use of sulfur-free liquid feedstocks (such as methanol) and lower-sulfur solid feedstocks (such as subbituminous coal from the Powder River Basin). Starting up the gasifiers using a liquid was not considered to be "available" for the TEC because Siemens does not offer the patented gasifier burner technology to accommodate liquid feedstocks. Utilizing low sulfur subbituminous coal was eliminated based on technical infeasibility. The gasifiers and the syngas processing train at the TEC are specifically designed for the moisture content, sulfur content, ash content, and heating value of the design feedstock (i.e., Illinois Basin bituminous coal) selected for the project to satisfy the requirements of the CCPSL. These coal feedstock properties can significantly influence the flow rate and composition of the syngas produced by the gasifiers which must be considered in the design of each individual process unit within the syngas conditioning train including the raw syngas scrubbers, CO shift unit, AGR unit, SRU, and methanation unit. Once a specific feedstock is chosen and the plant is developed for this specific feedstock, alternate feedstocks with significantly differing properties cannot be accommodated. Therefore, even though the gasification technology is feedstock flexible and may be able to use lower-sulfur feedstocks such as PRB coal or biomass/coal mixtures, nearly all of the process equipment in the coal drying, grinding, and feeding trains, gasifier trains, and syngas conditioning trains would not be compatible with such feedstocks.

The IEPA reviewed the BACT analysis for utilizing low sulfur feedstock for startup presented in the Application and developed additional details for the Project Summary to support the technical infeasibility determination for low sulfur subbituminous coal (refer to Project Summary, pages 38 and 39). This analysis is distinct from the

[327] NSR Manual, pp. B.31 - B.32.

completely separate discussion for feedstock selection in the Project Summary (Project Summary pages 24 and 26), as the comment suggests it should be. The permit record supports the conclusion that utilizing low sulfur feedstocks (such as sulfur-free liquid feedstocks, subbituminous coal, or a coal/biomass blend) during startup is not the BACT level control option to reduce SO_2 emissions from the flare at the TEC.

As previously discussed, the comment has incorrectly characterized the feedstock flexibility of the Siemens gasification technology selected for the project. Siemens gasifiers can accommodate subbituminous coal (and possibly coal/biomass mixtures) if the entire gasification system is designed from the outset to handle these feedstocks. A Siemens gasifier system designed to use Illinois Basin bituminous coal cannot utilize subbituminous coal or coal/biomass mixtures without causing potentially serious and frequent disruptions of the syngas supply to downstream processing equipment (such as the raw gas treatment unit, shift unit, AGR unit, and methanation units for the TEC) as well as in the gasifier feed system. Any alternative feedstock with properties that differ significantly from the normal variations in feedstock properties associated with Illinois Basin coal would pose the same operational challenges whether these are different ranks of coal or entirely different low-Btu feedstocks like biomass.

The comment correctly points out that the majority of the SO_2 emissions from the flare during gasification block startups and shutdowns occur when raw syngas is flared and the syngas is not being processed by equipment in the syngas conditioning train. However, it fails to consider the relevance of the syngas processing train design when evaluating the use of alternate startup feedstocks despite the clear discussion of this topic in the Project Summary (refer to page 38 of the Project Summary). Since the syngas processing train can only accommodate syngas produced by the design feedstock, an additional step would have to be added to the startup process whereby the gasifiers switch from the low-sulfur startup feedstock to the design feedstock. Assuming this complex transition could practically be accomplished, the additional feedstock transition step of the startup procedure would increase the length of time during which off-specification process gas streams would have to be flared and thus would likely increase the emissions of other pollutants, particularly CO and NO_X. The requirement to transition back to the design feedstock before the raw syngas could be fed forward into the process would also result in some period of time when raw syngas derived from the higher sulfur design feedstock would have to be flared. Depending on the magnitude of the differences in key properties between the design feedstock and a lower-sulfur startup feedstock, the duration of raw syngas flaring when utilizing the design feedstock in a "low-sulfur" startup may be nearly as long (and potentially longer in certain circumstances) as the 3 to 10 hour period required for a conventional startup on the higher sulfur design feedstock.

Additionally, the minimum turndown capacity of the SRU influences the ability to transition back to the design feedstock prior to completing a gasifier startup. To avoid an unplanned shutdown or the derating of the gasification block, the SRU must be designed to handle the maximum sulfur content of the feedstock. Based on the design capacity of the SRU (190 tpd) and the minimum turndown capacities of the gasifiers and the SRU trains (70% and 30%, respectively), the minimum acceptable coal sulfur

content required to achieve normal steady-state operation of the SRU during a gasification block startup is approximately 1.9% by weight on a dry basis (or at least 43% of the worst-case design coal sulfur content of 4.4%).[328] This minimum acceptable coal sulfur content is well above the average coal sulfur content for low sulfur subbituminous coal from the Powder River Basin (0.67% by weight), and therefore, low sulfur subbituminous coal could not be utilized during gasification block startups to reduce SO_2 emissions from the flare without negatively impacting the operation of the SRU.[329]

Based on a combination of technical issues, operational issues, and questionable emissions reductions, the IEPA appropriately concluded that use of low sulfur subbituminous coal or a coal/biomass mixture during gasifier startups is not a technically feasible control option for reducing SO_2 emissions from the flare.

The comment also suggests that a parallel milling, drying, and gasifier feed system train could be used to accommodate a low-sulfur, startup feedstock, thus alleviating concerns regarding the ability of the existing coal milling and drying system and gasifier feed system to handle alternate feedstocks. The Project Summary acknowledges that such a parallel feed system could be constructed and operated, but having dual feed systems does not alleviate the fundamental problem described above of having to switch back to the design feedstock before raw syngas could be fed forward into the syngas conditioning train.

The technical feasibility of utilizing low-sulfur alternate feedstocks during a gasifier shutdown is even more questionable than using these alternate feedstocks during a gasifier startup. To achieve any emissions reductions from utilizing low-sulfur feedstocks during the raw syngas flaring that occurs at the very end of a gasifier shutdown, CCG would have to begin feeding the alternate feedstock to the gasifiers long before the shutdown process was initiated so that this feedstock made it through the entire gasifier feed system (which has a capacity of approximately 8,000 tons, or two days of coal feed to the gasifiers). CCG does not expect that it could maintain a stable supply of syngas in terms of flow rate and composition when using any feedstock that differs significantly from the design Illinois Basin coal, so an emergency shutdown of the entire gasification block is likely to occur before CCG could implement a planned shutdown using low-sulfur subbituminous coal or a coal/biomass mixture.

The comment's claim is incorrect that other gasification projects routinely use a low sulfur coal pile to control non-routine flaring emissions, and the only support they provide for this statement is a reference to the permit for a single project (TransGas) that did not go through PSD review for SO_2 emissions from its flare. TransGas will not have a "low-sulfur coal pile" that will be used to control flaring SO_2 emissions, but

---

[328] **Per Condition 4.1.5-1(a), the combined maximum coal feed to the gasifiers, on an as-received basis, is 5,100 tpd. This feed rate is based on a maximum coal moisture content of 17%. The coal drying system is designed to lower the moisture level to 2%, so the maximum coal feed on a dry basis is 4,319 tpd (i.e., 5,100 tpd x (100% - 17%)/(100% - 2%) = 4,319 tpd). At the minimum turndown capacity of the gasifiers (70%), this coal feed rate corresponds to 3,024 tpd. The minimum sulfur feed rate needed to keep the SRU online is 57 tpd (i.e., 190 tpd design sulfur feed rate x 30% turndown capacity = 57 tpd). Therefore, the minimum acceptable coal sulfur content to achieve steady-state operation of the SRU during gasifier startups (including both a cold plant startup and single gasifier startup) is 1.9% by weight, dry basis.**

[329] **USGS, Rocky Mountain/Great Plains Coal Assessment, Regional Coal Quality Data, available at http://energy.usgs.gov/Coal/AssessmentsandData/CoalAssessments/RockyMountainGreatPlainsCoalAssessment.aspx**

instead will utilize local, low-sulfur bituminous coal as its design feedstock and will simply have to ensure that the sulfur content of the coal fed to the gasifiers during a startup remains below 0.5%.[330] As discussed below, it is not cost effective for TEC to use Appalachian coal as the design feedstock; nor would it be consistent with the purpose of the facility to satisfy the requirements of the CCPSL.

CCG does not have the ability to readily and consistently obtain low sulfur bituminous coal from the local Illinois Basin suppliers that it is most likely to use. As discussed previously, USGS samples for Herrin coal that have lower sulfur content than the proposed design coal do not indicate that this coal would be readily available. The overall goal of this USGS study (Commenter's Exhibit 17) is to provide an overview of the geologic setting, distribution, resources, and quality of Pennsylvanian coal in the Illinois Basin. The sulfur content and other chemical properties for Illinois Basin coals presented in the USGS report is a compilation of data that were collected over the last 50 years by the USGS, Illinois State Geological Survey (ISGS), Indiana Geological Survey (IGS), and Kentucky Geological Survey (KGS). As such, this study includes sulfur content data from mines that have long been abandoned or mines whose reserves will be depleted within the lifetime of the TEC. The USGS study entitled *The National Coal Resource Assessment Overview Chapter H: Production and Depletion of Appalachian and Illinois Basin Coal Resources* cited previously provides a much more comprehensive analysis of the sulfur content of Illinois Basin coal in the current market and the sulfur content and production rate of Illinois Basin coal in the future. This study reflects the current scarcity of low-sulfur Illinois Basin coal. Therefore, due to the lack of certainty in future availability of low sulfur Illinois coal, it should not be required for use during gasifier startups. Less than 5% of the coal produced in the Illinois Basin contains 2.0% sulfur or less and more than 90 percent of the coal produced in Illinois contains 3% sulfur or higher.[331] According to SNL Energy's Physical Market Report, the lowest sulfur coal available from the Illinois Basin that can be purchased currently on the open market as a commodity product is 2.5%.[332] Over the 30 year life of the plant, the already scarce low-sulfur coal resources in the Illinois Basin are expected to become scarcer as the demand for low-sulfur coal increases to supply the numerous coal-fired power plants in the Midwest with ever tightening SO_2 emission limits. The flare SO_2 BACT limits established for the TEC must be achievable on a continuous basis over the lifetime of the plant, so CCG appropriately used a sulfur content of 4.4% to estimate emissions, demonstrate compliance with the NAAQS, and establish the flare BACT limits.

---

[330] The TransGas facility will use Udhe PRENFLO™, dry-feed, entrained flow gasifiers with direct syngas quench. (from West Virginia DEP, Engineering Evaluation/Fact Sheet for TranGas Development, LLC, available at http://www.dep.wv.gov/daq/permitting/Pages/default.aspx.) While the gasifier systems at TEC and TransGas are similar and would share the same difficulties with accommodating feedstocks that vary significantly from the design feedstock, the main difference between the TransGas and TEC projects is the proximity to low-sulfur bituminous coal resources. The TransGas plant will be located in Mingo County, West Virginia which is located in the heart of the Appalachian coal basin that produces much higher quantities of low-sulfur coal than the Illinois Basin. In fact, West Virginia has more low sulfur bituminous coal reserves than any other state in the Appalachian or Illinois Basins. Nearly 40% of the coal reserves in West Virginia have a sulfur content of less than 0.60 lb S/mmBtu (i.e., 0.72% at a representative bituminous coal heating value of 12,000 Btu/lb, as received). In contrast, less than 1% of the coal reserves in the Illinois Basin have a sulfur content of less than 0.60 lb S/mmBtu. (from USGS, The National Coal Resource Assessment Overview Chapter H: Production and Depletion of Appalachian and Illinois Basin Coal Resources, 2009, available at http://pubs.usgs.gov/pp/1625f/downloads/ChapterH.pdf.)

[331] USGS, The National Coal Resource Assessment Overview Chapter H: Production and Depletion of Appalachian and Illinois Basin Coal Resources, 2009, available at http://pubs.usgs.gov/pp/1625f/downloads/ChapterH.pdf, p. 8.

[332] SNL Energy Coal Report, Volume 8 Issue 14, April 2, 2012.

Due to the scarcity of low sulfur coal in the Illinois Basin, CCG's only option for using low-sulfur bituminous coal as the design feedstock would be coal from the Appalachian Basin. For TEC, this coal has a significantly higher delivered price (projected at $88.35 to 91.28/ton in 2013) than the cost of high-sulfur coal from the Illinois Basin ($45.88/ton in 2015).[333, 334] Based on the difference in coal costs alone, the following cost analysis demonstrates it would not be cost effective for CCG to change the design coal for the project from Illinois Basin coal to low-sulfur Appalachian Basin coal (obtained from the same area of West Virginia that the TransGas project will obtain its coal) for the purposes of reducing the SO_2 emissions of the TEC by 412.6 tpy.[335]

---

[333] **The costs for low sulfur Eastern bituminous coal from the Central Appalachian Basin, at the mine, undelivered, are taken from the April 2, 2012 SNL Energy Physical Market Report, and the delivery costs for rail transport ($20/ton) are based on an estimate from project engineers with past experience procuring coal contracts for industrial facilities. The costs for the design coal are taken from Exhibit 6 of the Facility Cost Report (available at http://www.icc.illinois.gov/electricity/tenaska.aspx) entitled *Wood Mackenzie Study The Delivered Price of Coal to the Taylorville Energy Center*. The only future calendar year available in the SNL Energy Report is 2013, and the earliest calendar year available in the Wood Mackenzie study is 2015. Using the earliest future calendar year available in both documents should result in a conservative cost analysis since it does not reflect any cost escalation over the life of the plant due to inflation.**

[334] **One factor in the cost of low-sulfur bituminous coal may the various regulations pursuant to the Clean Air Act that are focusing on reducing SO_2 emissions from coal-fired power plants,**

[335]

Cost Analysis for Using Eastern Bituminous Coal as the Design Feedstock

Feedstock Characteristics

Feedstock	Heating Value, HHV (Btu/lb, as received)	Sulfur Content, as received (wt%)	SO_2 Emissions Potential[3] (lb/ton)	SO_2 Emissions Potential[4] (lb/MMBtu)
Illinois Basin Bituminous Coal[1]	11,800	4.4	176.0	7.5
Low Sulfur Eastern Bituminous Coal[2]	12,500	1.9	76.0	3.04

[1] Heating value and sulfur content of Illinois Basin coal based on anticipated coal properties from local supplier.

[2] Low-sulfur Eastern bituminous coal heating value is taken from the Thacker/Kenova 1.5% sulfur coal product listed on the April 2, 2012 SNL Energy Physical Market Report. Low-sulfur Eastern bituminous coal sulfur content is set to the minimum acceptable coal sulfur content for the TEC.

[3] Calculated from coal sulfur content using the molecular weight ratio of SO_2 to sulfur.

[4] Calculated from the SO_2 emissions potential on a lb/ton basis using the coal heat value.

Annual Feedstock Costs

Feedstock	Annual Feedstock Usage (ton)	Delivered Cost ($/ton)	Total Feedstock Cost ($)	Difference in Fuel Cost vs. Baseline ($)
Illinois Basin Bituminous Coal[1]	1,860,000	45.88	$ 85,336,800	Baseline
Low Sulfur Eastern Bituminous Coal[2]	1,757,256	89.40	$ 157,098,686	$ 71,761,886

[1] Annual feedstock usage is based on Condition 4.1.5-1(a) of the Draft Permit. Delivered coal cost of Illinois Basin coal for the TEC in 2015 is taken from page 8 Exhibit 6 to the Facility Cost Report (available at http://www.icc.illinois.gov/electricity/tenaska.aspx).

[2] Feedstock usage for low sulfur Eastern bituminous coal is determined based on the total coal heat input to gasifiers on an as received basis required for the Illinois coal case (5,015 MMBtu/hr) divided by the heating value of Eastern bituminous coal (25 MMBtu/ton, as received) and multiplied by 8,760 hr/yr assuming continuous operation. Delivered cost for low sulfur Eastern bituminous coal is based on coal cost for Thacker/Kenova 1.5% sulfur coal product listed on the April 2, 2012 SNL Energy Physical Market Report ($71.28/ton in Calendar Year 2013) plus the estimated rail delivery costs ($20/ton).

SO_2 Emissions Fuel Cost Comparison

Feedstock	SO_2 Emissions Potential[1] (tpy)	Controlled SO_2 Emissions[2] (tpy)	Sulfur Recovery Efficiency[2] (tpy)	Average Cost ($/ton)	Incremental Cost ($/ton)
Illinois Basin Bituminous Coal	163,680	696.9	99.6%	524	-
Low Sulfur Eastern Bituminous Coal	66,776	284.3	99.6%	2,363	173,938

[1] Product of SO_2 emissions potential in lb/ton multiplied by the annul feedstock usage assuming all sulfur in the feedstock(s) is emitted to the atmosphere without the benefit of the sulfur recovery process.

[2] Controlled emissions from the Illinois Basin coal case are equivalent to the plant-wide annual potential emission from the TEC. The controlled SO_2 emissions for the low sulfur Eastern bituminous coal case are based on the SO_2 emissions potential and the sulfur recovery efficiency for the Illinois coal design case assuming the sulfur recovery efficiency for the plant will be similar under both feedstock cases.

To further address the comments regarding use of a lower sulfur bituminous coal during startup and shutdown of the gasification block, CCG evaluated the feasibility and practicality of such a requirement for single gasifier startup and shutdown events and cold plant startup and total plant shutdown events. Assuming that CCG could routinely obtain low-sulfur bituminous coal for use during single gasifier startups and shutdowns, the operational issues associated with transitioning feedstocks from the low sulfur startup feedstock contained in one coal storage and handling system to the design feedstock contained in a separate coal storage and handling system would still be present. The active storage pile has a 30-day capacity and the silos and bunkers within the gasifier feed system also have significant storage capacity. During these single gasifier events, the only equipment affected is the gasifier planned to be taken out of service or returned to service while the other gasifier and the rest of the equipment in the gasification block must continue to operate normally. Since both gasifiers share a single active storage pile, crusher, and crusher surge bin (refer to Figure 2-3 of Volume 1 to the Application), the single gasifier planned for startup or shutdown must use the same coal as the gasifier that remains online. To utilize low sulfur coal during these single gasifier events, CCG would need to design, construct, and operate a separate coal pile, crusher, and conveyor system to serve the gasifier feed system for each gasifier. For a single gasifier startup to be successful, CCG would have to seamlessly transfer from the low sulfur coal feed train to the design coal feed train without disrupting the operation of the syngas processing train. For a shutdown, CCG would have to switch from the main coal feed system to the alternate, low-sulfur feed system as much as 48 hours ahead of the planned single gasifier shutdown to ensure that low-sulfur coal was being fed to the gasifier before the shutdown was initiated. Requiring this complex feedstock transition process to potentially reduce SO_2 emissions during a brief period of single gasifier startups and shutdowns is not practical or feasible. Use of low sulfur Illinois Basin coal during single gasifier startups and shutdowns is also not practical in light of the uncertainty regarding the long-term availability of low-sulfur coal from the Illinois Basin. In addition, CCG projects as many as 12 single gasifier startups and 12 single gasifier shutdown events per year (total 24 events), which means that a startup or shutdown could occur as frequently as semimonhly. Given this number of annual single gasifier startup/shutdown events, requiring CCG to use lower-sulfur bituminous coal to reduce SO_2 emissions from the flare would essentially require CCG to use this lower-sulfur coal as the design feedstock, which has been determined to be cost ineffective.

During the once-per-year total shutdown the gasification block, with subsequent cold startups of both gasifiers, CCG could theoretically utilize the existing coal feed system to supply low-sulfur Eastern bituminous coal to the gasifiers. Since handling Eastern bituminous coal in the existing coal feed system would not pose as many technical challenges as the parallel feed system, CCG prepared a cost analysis to evaluate whether the use of low sulfur Eastern bituminous coal during these events is a cost effective control option for reducing SO_2 emissions from the flare.[336] The annual SO_2

336

emissions from the flare during total plant shutdowns and subsequent cold startups are 76.2 tpy as compared to the total annual SO_2 emissions from the flare of 550.8 tpy. Therefore, the SO_2 emissions reduction that could be achieved with low-sulfur bituminous coal during and total plant shutdowns and startups is only 45.1 tpy (or less than 10 percent of the annual potential SO_2 emissions from the flare when utilizing the design coal). Based on the difference in coal costs alone, the following cost analysis demonstrates it would not be cost effective for CCG to utilize low sulfur Eastern bituminous coal during cold plant startups and total plant shutdowns for the purposes of reducing the SO_2 emissions from the flare by 45.1 tpy.[337]

Cost Analysis for Using Eastern Bituminous Coal during Cold Plant Startups and Total Plant Shutdowns

Feedstock Characteristics

Feedstock	Heating Value, HHV (Btu/lb, as received)	Sulfur Content, as received (wt%)	SO_2 Emissions Potential[3] (lb/ton)	SO_2 Emissions Potential[4] (lb/MMBtu)
Illinois Basin Bituminous Coal[1]	11,800	4.4	176.0	7.5
Low Sulfur Eastern Bituminous Coal[2]	12,500	1.9	76.0	3.04

[1] Heating value and sulfur content of Illinois Basin coal based on anticipated coal properties from local supplier.

[2] Low-sulfur Eastern bituminous coal heating value is taken from the Thacker/Kenova 1.5% sulfur coal product listed on the April 2, 2012 SNL Energy Physical Market Report. Low-sulfur Eastern bituminous coal sulfur content is set to the minimum acceptable coal sulfur content for the TEC.

[3] Calculated from coal sulfur content using the molecular weight ratio of SO_2 to sulfur.

[4] Calculated from the SO_2 emissions potential on a lb/ton basis using the coal heat value.

Annual Feedstock Costs

Feedstock	Annual Feedstock Usage during Cold Plant Startup and Total Plant Shutdown (ton)	Delivered Cost ($/ton)	Total Feedstock Cost ($)	Difference in Fuel Cost vs. Baseline ($)
Illinois Basin Bituminous Coal[1]	12,500	45.88	$ 573,500	Baseline
Low Sulfur Eastern Bituminous Coal[2]	11,810	89.40	$ 1,055,771	$ 482,271

[1] Annual feedstock usage during cold plant startup and total plant shutdown events is based on the per event coal usage (i.e., 4,500 ton/event for a cold plant startup and 8,000 ton/event for a total plant shutdown) and the annual number of events used in the flare annual potential emission calculations (i.e., 1 cold plant startup and total plant shutdown per year). The cold plant startup coal throughput rate is based on the period from introduction of coal to the first gasifier to stable steady-state production of on-spec SNG from both gasifiers and does not include any additional low-sulfur coal throughput to accommodate for the switch back to the design coal. The total plant shutdown coal throughput rate is based on the capacity of the gasifier feed system from the outlet of the coal crusher to the gasifier burner since the feed system would have to be purged of design coal to allow for low sulfur coal to be fed to the gasifiers during the shutdown. Delivered coal cost of Illinois Basin coal for the TEC in 2015 is taken from page 8 Exhibit 6 to the Facility Cost Report (available at http://www.icc.illinois.gov/electricity/tenaska.aspx).

[2] Feedstock usage for low sulfur Eastern bituminous coal is determined based on the ratio of the annual Eastern bituminous coal usage presented in the design feedstock change cost calculations (1,757,256 tpy) to the annual design coal throughput used in these same calculations (1,860,000 tpy) multiplied by the design coal throughput for cold plant startups and total plant shutdowns. Delivered cost for low sulfur Eastern bituminous coal is based on coal cost for Thacker/Kenova 1.5% sulfur coal product listed on the April 2, 2012 SNL Energy Physical Market Report ($69.40/ton in Calendar Year 2013) plus the estimated rail delivery costs ($20/ton).

337

While this cost analysis provides sufficient justification for eliminating the use of low sulfur Eastern bituminous coal during cold plant startups and total plant shutdowns, it does not address the use of low-sulfur Illinois coal during these events. For a startup, CCG would have to purge the raw coal silos, pulverizers, coal milling and drying baghouse, coal bunker, and lockhoppers in the gasifier feed system of the design coal before the startup, low-sulfur bituminous coal could be fed to the system. The limiting factor in this case would be the availability over the 30-year life of the facility of a sufficiently large quantity of low-sulfur bituminous coal to ensure that the gasifier could transition back to the design coal before the low-sulfur coal supply ran out during a cold startup, as well as a sufficiently large quantity of low-sulfur coal to supply the gasifiers over the entire duration of the total plant shutdown. Based on the capacity of the active storage pile and all of the equipment in the gasifier feed system, CCG would likely have to obtain up to a one week supply of low-sulfur bituminous coal (up to 35,700 tons) to accommodate either the cold plant startup or total plant shutdown feedstock transition process. Given the scarcity of low-sulfur Illinois Basin coal, it is infeasible to impose this type of operational constraint on TEC to theoretically reduce the flare SO_2 emissions by a relatively small amount during cold startups and total plant shutdowns. In addition, any mine that has low sulfur Illinois coal would likely be reluctant to contract with a facility that will only be purchasing their coal for a once per year event. Without a mine under contract, CCG would be left to obtain coal from the open market. Low sulfur Illinois coal may not be available on the open market in the requisite quantities and at the necessary times for use as an alternate feedstock during cold plant startups and total plant shutdowns over the life of the TEC. BACT limits must be achievable on a continuous basis over the lifetime of the source, so these limits cannot be premised on the use of a feedstock which may not be available at all times.

76. The Draft Permit would not actually require Flare Minimization. The Draft Permit would require operation according to detailed procedures to minimize emissions (Condition 4.1.5-1(e)), flare minimization planning (Condition 4.1.5-3), and root cause analysis (Condition 4.1.5-3d). However, these conditions do not actually require that flaring be minimized and do not satisfy BACT. Elements of an effective, enforceable flare minimization plan include those discussed below, which are missing from both the BACT analysis and the resulting Permit conditions.

Cost Analysis for Using Eastern Bituminous Coal during Cold Plant Startups and Total Plant Shutdowns

SO_2 Emissions Fuel Cost Comparison

Feedstock	SO_2 Emissions Potential[1] (tpy)	Controlled SO_2 Emissions[2] (tpy)	Average Cost ($/ton)	Incremental Cost ($/ton)
Illinois Basin Bituminous Coal	1,100	76.2	560	-
Low Sulfur Eastern Bituminous Coal	449	31.1	2,528	10,694

[1] Product of SO_2 emissions potential in lb/ton multiplied by the annul feedstock usage assuming all sulfur in the feedstock(s) is emitted to the atmosphere without the benefit of the sulfur recovery process.

[2] Controlled emissions from the Illinois Basin coal case are equivalent to the sum of the annual potential SO_2 emissions from the flare during cold plant startups and total plant shutdowns (i.e., 35.28 tpy + 40.89 tpy = 76.2 tpy, refer to Tables C-3.3 and C-3.4 of Volume 1 to the Application). The controlled SO_2 emissions for the low sulfur Eastern bituminous coal case are based on the annual potential SO_2 emissions from the flare during cold plant startups and total plant shutdowns multiplied by the ratio of the SO_2 emissions potential for low sulfur Eastern bituminous coal to the SO_2 emissions potential for Illinois Basin coal.

Limits should be set on the amount of time equipment is permitted to operate during a malfunction. The BACT analysis did not discuss such limits and the Draft Permit does not establish any. Gasifiers are able to shut down in a matter of hours, and should be required to do so within a short period of time if they are the source of gas that is being flared. A permit issued to Power Holdings requires shutdown within 3 hours of a malfunction that would cause emissions to be exceeded, unless the malfunction is expected to be repaired within 3 hours, or such shutdown could threaten the safety of personnel or equipment.[338]

Root cause analyses should be performed on all malfunctions or a certain subset thereof (*e.g.*, those releasing over a certain threshold of emissions). The Draft Permit limits eligible events to only those with higher emissions than a cold startup. Condition 4.1.5-3d.[339] A much larger subset of events should be subject to root cause analysis. The South Coast Air Quality Management District flare regulation requires root cause analysis for any flare event emitting greater than 500 lbs/day SOx, but also for any flare event with greater than 100 lbs/day of VOCs.[340] The Draft Permit would only require a root cause analysis if emissions were orders of magnitude higher.

The permit should require that prior to being flared, process gas pass through as much of the syngas cleanup system as feasible, even during a malfunction. For instance, the recently reissued permit for Southeast Idaho Energy requires upset gas to pass through the sour water scrubber, the activated carbon beds, and an amine scrubber to reduce the sulfur content prior to being flared.[341]

The BACT analysis and permit should require a preventative/predictive maintenance plan. Some malfunctions are the result of insufficient maintenance and could be prevented with a routine schedule of preventative maintenance (rather than waiting until something is broken). A predictive maintenance plan monitors certain parameters and helps to anticipate where maintenance is most likely to be needed.

The BACT analysis and permit should require evaluation and procurement of backups for key pieces of equipment (optimization of redundancy where appropriate). For example, Eastman's Kingsport gasification facility has significantly decreased its forced outage rate through detailed reliability and redundancy modeling. The Application and Draft Permit are silent as to redundancy.

The BACT analysis and permit should require a flare monitoring plan detailing the monitoring equipment discussed below and operating procedures for the monitoring equipment, provided in advance of approval of the project. Without accurate feedback about flare emissions, flare minimization planning is not effective. Without rigorous monitoring,

[338] Power Holdings Permit, at 1-99.
[339] Condition 4.1 .5-3.d requires root cause analysis only for "flaring incidents." A "flaring incident is defined as a flaring event that produces excess emissions above permit limits and accompanies the unscheduled shutdown of the gasification block or a malfunction of a process unit that results in process gas being routed to the flare." The subject permit limits at Condition 4.1.6.b are the limits for a cold startup. Thus, many lesser, though still very large, malfunctions could occur repeatedly without triggering a root cause analysis. Further, the Draft Permit does not contain sufficient monitoring to determine when these limits are exceeded. *See* Comment --.
[340] SCAQMD Rule 1118 at 1118-5.
[341] Southeast Idaho Energy Permit.

flaring events can go undetected, unreported, or underestimated. A root cause analysis requirement would not be triggered for events that go undetected.

The Power Holdings Flare Minimization Plan, for example, is detailed and lengthy. All of these detailed requirements in the Power Holdings flare minimization plan set the BACT standard and must be required for the TEC. These include the requirements for procedures for preventative maintenance; procedures for periodic evaluation of flaring activity generally and specific evaluation of flaring incidents; and an evaluation of preventative measures to reduce the occurrence and magnitude of flaring for the gasification block.

The comment acknowledges that the permit contains detailed procedures for flare minimization and root cause analysis, but identifies additional elements of an effective flare minimization strategy that it believes should have been considered. At the outset, it should be noted that the permit establishes enforceable numeric BACT limits for the flare for all operations, including startup, shutdown and malfunction. The flare minimization and root cause analysis are additional requirements to further minimize emissions.

The comment suggests that the permit should include limits on the duration of malfunctions. The comment does not demonstrate how such limits on duration would actually result in lower emissions given the requirements that are already in the permit to minimize emissions. Condition 3.4(c) imposes the definition of malfunction in 40 CFR 63.2 which matches the USEPA malfunction criteria established in the Boiler MACT. Conditions 3.5, 4.1.5-1(e) and 4.1.5-2(b) require good air pollution control practices to be implemented at all times. These provisions include preventative maintenance and repair requirements and good monitoring practices to ensure that malfunctions are prevented to the greatest extent practicable and when they do occur that they are identified as quickly as possible. Consistent with Illinois' State Implementation Plan, Condition 4.1.3 only allows continued operation of the gasification block when the opacity of flare emissions exceeds 30 percent and/or the SO_2 emissions exceed 2000 ppm if: 1) such continued operation is necessary to prevent risk of injury to personnel or severe damage to equipment, provided however, that operation shall not continue solely for the economic benefit of the owner or operator of the plant, and 2) CCG repairs the unit(s) that are responsible or remove unit(s) from service as soon as practicable in accordance with the good air pollution control practice requirement in Conditions 3.6 and 4.1.5-1(e). For all gasification block BACT limits, Condition 4.1.5-1(e) requires CCG to identify and address likely malfunction events with specific programs of corrective actions. If the malfunction is expected to result in excess emissions above the permit limits in Condition 4.1.2 and 4.13, CCG is required to repair the affected equipment, reduce the operating rate of the gasification train or remove the gasification train from service as soon as practicable so that excess emissions cease. Continuing to operate malfunctioning equipment on a normal steady-state basis is only allowed if this is the best course of action to comply with the good air pollution control practice requirements of the permit (i.e., if attempting to repair the equipment while it is malfunctioning will produce less emissions than shutting down the entire process).

Specifying the maximum duration of malfunction events also is not an approach that USEPA has ever endorsed in any of its NSPS or NESHAP rules. Instead, USEPA relies on the requirement to operate in accordance with the "general duty" to minimize emissions during malfunctions in accordance good air pollution control practices, and requires sources to provide an affirmative defense that the malfunction event was not caused by poor maintenance or careless operation and that the corrective actions implemented to address the event complied with the "general duty" clause.

An example of this approach is found in the recently proposed Boiler NESHAP (40 CFR 63 Subpart DDD). Although this rule would not be applicable to the gasification block at the TEC, a comparison of the regulatory approach taken by USEPA in the Boiler NESHAP to the structure for addressing flaring during malfunction events in the permit reveals that the permit is consistent with USEPA's most recent recommendations for the best approach to address emission limit exceedances during malfunction events.[342]

The comment refers to a permit requirement for the Southeast Idaho Energy (SIE) facility as the basis for recommending that the permit should require process gas treatment prior to flaring during a malfunction. By requiring CCG to conduct good air pollution control practices at all times, the permit would inherently require process gas generated during a malfunction to pass through as much of the syngas cleanup system as feasible prior to being flared. Furthermore, Condition 4.1.10-2 requires CCG to record the amount and nature of the process gas sent to the flare, with a detailed explanation if partially cleaned syngas was flared. Finally, the use of a low pressure, amine-based absorption system (similar to the system proposed at SIE) as a backup control device for reducing SO_2 emissions from raw or sour syngas flaring was addressed explicitly as an available control option in the BACT evaluation conducted for the flare. As discussed on page 38 of the Project Summary, an amine-based absorption system was eliminated on the basis of both technical infeasibility and the minimal control effectiveness that is expected. This same conclusion would apply to the use of such a system during malfunction events that required venting of raw syngas downstream of the raw gas treatment system or sour syngas upstream of the AGR unit.

Although an amine scrubber is not technically feasible, in the event of a SRU malfunction, CCG is required to route acid gas emissions to the SRU thermal oxidizer and caustic scrubber for reducing SO_2 emissions, where possible, rather than routing it to the flare [refer to Condition 4.1.2-1(b)(iv)]. Avoiding acid gas flaring in this manner will drastically reduce the SO_2 emissions that would otherwise occur if acid gas was flared without the benefit of control. To maintain compliance with the annual flare SO_2 BACT limits that include emissions from malfunctions, CCG will have to properly

---

[342] **In contrast to the malfunction requirements included in the permit which allow continued operation of malfunctioning equipment only if certain prerequisites are met, Condition 4.4.5(a)(iii)(B) of the Power Holdings permit only requires a shutdown of gasifiers within 4 hours, unless the malfunction is expected to be repaired within 6 hours.[342] Power Holdings included in its application a Form 204-CAAPP which provides applicant's with the opportunity to "Request to Continue to Operate During Malfunction or Breakdown" under the requirements of 35 IAC 201.262. Pursuant to 35 IAC 201.262, permission to operate during a malfunction can only be granted if the applicant submits proof to the IEPA that: 1) continued operation is necessary to prevent injury to persons or severe damage to equipment; or 2) continuing to operate is required to provide essential services (economic benefits to the source cannot be cited as ground for seeking permission to continue to operate during a malfunction). CCG did not complete this form as part of the Application, and is not seeking permission to continue to operate during a malfunction unless such continued operation is consistent with good air pollution control practices.**

operate and maintain the plant so as to avoid flaring significant quantities of process gases during malfunctions since such unplanned flaring events could compromise the ability of the plant to demonstrate compliance with the flare BACT limits.

The comment next suggests that root cause analyses should be required for all malfunction events or at least certain malfunction events that cause emissions over a specific threshold (which should be established at a level that is below the current permit limits). The permit appropriately requires a formal root cause analysis, including a formal incident investigation and detailed reporting requirements [Condition 4.1.5-3(d)], for flaring events that produce excess emissions above the permit limits. Smaller malfunction events which do not cause exceedances of emission limits are more appropriately addressed through more general flare minimization and corrective action program requirements. For example, Condition 4.1.5-3(a)(vii) of the permit requires a detailed description of CCG's procedures for periodic evaluation of flaring activity generally and specific evaluation of flaring incidents, including identification of the causes of flaring, assessment of measures to eliminate or reduce flaring, and implementation of feasible measures to reduce flaring. In conjunction with the requirements to monitor the date, time, and duration of each occurrence of process gas venting to the flare (Condition 4.1.8-2) and to record the emissions, the probable cause, and corrective actions from each flaring event (Condition 4.1.10-2), the flare minimization requirements of the permit will ensure emissions are minimized in accordance with good air pollution control practices for all flare events regardless of the emissions they produce or when they occur. Detailed records are required for each event when process gas is flared.[343]

With no emissions threshold for triggering these recordkeeping requirements, the permit is more stringent than the SCAQMD root cause analysis requirements cited by the comment. SCAQMD Rule 1118 for control of emissions from refinery flares requires investigations into the cause of a flaring event only if it produces more than 500 pounds of SO_2, 100 pounds of VOC, or 500,000 scf of flare gas flow rate. The permit, however, requires CCG to document the probable cause for all flaring events.[344] A comparison of the other, relevant flare minimization requirements in Rule 1118 reveals that the permit contains nearly all of the same monitoring, recordkeeping, reporting, and plan development requirements as the SCAQMD rule. Therefore, the presence of this rule and IEPA's supposed failure to address it did not lead to a deficient BACT analysis for the flare.

---

[343] **For each event when process gas is flared, Condition 4.1.10-2 requires recordkeeping for the following:**

1. **Date, time and duration of flaring.**
2. **Description of the event, a discussion of the cause(s) and probable cause(s) of the event.**
3. **Confirmation that established operating procedures were followed.**
4. **Confirmation that the flare functioned properly, i.e., a flame was present and any visible emissions that occurred were in compliance with 40 CFR 60.18(f)(1).**
5. **The amount and nature of the process gas sent to the flare, with detailed explanation if partially cleaned syngas was flared.**
6. **The amount of CO, H_2S and VOM contained in the gas sent to the flare and the amount of CO, H_2S, SO_2 and VOM emitted, pounds/event, with supporting calculations.**
7. **Whether SO_2 emissions of the flare(s) may have exceeded the standard of 35 IAC 214.301, i.e., 2000 ppm, on an hourly average.**
8. **Corrective actions taken during the event.**
9. **A description of any actions taken to prevent or reduce the likelihood of similar future occurrences.**

[344] **SCAQMD Rule 1118(c)(1)(D)**

The comment ignores many of the permit conditions addressing preventative maintenance when citing deficiencies in the permit for ensuring that adequate maintenance is performed to avoid malfunction emissions from flaring. Condition 3.6 requires CCG to conduct routine inspections and to perform appropriate maintenance and repairs to facilitate proper functioning of equipment and to minimize or prevent malfunctions. The good air pollution control practices incorporated as BACT requirements in Condition 4.1.2-1(c)(iii) require CCG to conduct inspections, maintenance, and repairs of units in accordance with written maintenance procedures required by Condition 6.2(b). These conditions are only a few of the primary examples of the maintenance requirements in the permit.

The comment cites reliability and redundancy modeling conducted at Eastman's Kingsport facility as a means for reducing the forced outage rate at a coal gasification facility and presumably also reducing the emissions that occur during these outages. No reference is provided to document the experiences of Eastman's facility, so neither the IEPA nor CCG cannot definitively evaluate whether the redundancies in place at this site are even relevant or applicable to the TEC.

Consistent with the comment's recommendation, Condition 4.1.8-2(g) does require a flare monitoring plan. Moreover, as the comment claims that the flare minimization plan requirements in the Power Holdings permit should "set the BACT standard" for the TEC.[345] Condition 4.1.5-3 of the Power Holdings permit entitled *Flare Minimization Planning* is nearly identical to the equivalent section of the permit (refer to Condition 4.1.5-3 of the TEC Permit). Both permits require the following: 1) development of a Flare Minimization Plant (FMP) containing the same information [Conditions 4.1.5-3(a) and (b) in both permits], and 2) root cause analyses for each flaring incident based on the same incident investigation and reporting requirements [Condition 4.1.5-3(d) in both permits], 3) a flare monitoring plan [Condition 4.18-2(e) in the Power Holdings permit and Condition 4.1.8-2(g) in the TEC permit], 4) identical recordkeeping requirements for each flaring event, [Conditions 4.1.10(c) in the Power Holdings permit and Condition 4.1.10-2(b) in the TEC permit], and 5) identical preventative maintenance requirements [Conditions 3.5(b) and 5.2(b) in the Power Holdings permit and Conditions 3.6(b) and 6.2(b) in the TEC permit]. A more careful comparison of the permits for Power Holdings and the TEC shows that they have all of the same elements which the comment suggests are necessary as part of BACT determination for the flare. If the Power Holdings permit "sets the BACT standard" as contended by the comment, then the permit for the TEC meets that standard.

77. Alternative flare technology was not adequately considered. The flare for the TEC is currently designed as an elevated flare. Flare exposure to wind significantly reduces combustion efficiencies. In addition, direct monitoring of an elevated flare is not as feasible as with a ground flare. This could be remedied by the use of an enclosed ground flare for the expected periodic events associated with gasifier startup. The application eliminated a ground flare as not an available control option due to noise, heat, and other objectionable

[345] **Sierra Club/Natural Resources Defense Council, Comments, p. 76.**

attributes.[346] However, no support is provided for these speculations. Further, they are inconsistent with experience elsewhere.

The Bay Area Air Quality Management District ("BAAQMD") in California, where five petroleum refineries are located, identifies use of an enclosed ground flare as BACT for flare emissions. The BAAQMD also assigns an assumed VOC destruction efficiency of 98.5% to an enclosed ground flare, higher than the assumed destruction efficiency of 98% assumed by the BAAQMD for all other flares. This VOC destruction efficiency is valid under all wind conditions, as the enclosed ground flare is completely protected from crosswinds.

A single enclosed ground flare could readily accept a maximum gasifier startup flare gas flow. An additional backup elevated flare may also be required to handle much larger malfunction events, not disclosed in the Application. Flares, either enclosed ground flares or elevated emergency flares, are relatively inexpensive pieces of equipment. The capital cost of an enclosed ground flare capable of handling 100 tons per hour of VOCs is approximately $4 to $5 million. An elevated flare capable of handling ten times this heat input under force majeure emergency conditions costs approximately $1.5 to 2 million.

Flare BACT would be an enclosed ground flare to combust gasifier startup off-gases and an elevated flare, for all unplanned flaring events that exceed the capacity of the enclosed ground flare. The addition of an enclosed ground flare, while costing several million dollars, must be considered in the context of this multi-billion dollar project.[347] The BACT analysis did not evaluate a ground flare, but rather dismissed it as not available, without any explanation. The Application argues that "[a]n elevated flare is required to prevent the potential for excessive radiative heat and harmful concentrations of certain pollutants if the flare were to malfunction. Furthermore, with an elevated flare, the products of combustion can be dispersed above working areas to reduce the effects of noise, heat, and other objectionable attributes."[348] No support for these claims is provided.

This is contrary to the experience and findings of the BAAQMD, reported above.[349] Further, it is contrary to USEPA analyses[350] and vendor experience, who report no visible flame, virtually no radiation (refractory-line combustion chamber), very low noise (enclosed), high destruction rates, and long service life.[351]

In an enclosed flare, the burner heads are located inside of an internally insulated shell. This shell reduces noise, luminosity, and heat radiation and provides wind protection, contrary to the unfounded allegations in the Project Summary. Further, stable combustion can be

---

[346] Ap., v. 1, p. 6-3.
[347] Kentucky NewGas Project Overview, ConocoPhillips, Peabody, available at http://www.kentuckynewgas. com/wp-content/uploads/2008/12/ProjectFactSheetl.pdf (stating that "Kentucky NewGas is a multi-billion dollar project in Western Kentucky"). (Commenter's Exhibit 74)
[348] Ap., v. 1, p. 6-3.
[349] *See* also San Joaquin Valley Air Pollution Control District Rule 4311, which sets VOC limits on unassisted enclosed ground flares of 0.0013 mmBtu, which is four times lower than VOC emission rate assumed for the elevated flare or 0.0054 lb/mmBtu (Ap., v. 1, p. C-7).
[350] USEPA, Benefits of an Enclosed Gob Well Flare Design for Underground Coal Mines, Addendum to: Conceptual Design for a Coal Mine Gob Well Flare, Report EPA 430-R-99-012, August 1999, http://www.epa.gov/cmop/docs/022red.pdf. (Commenter's Exhibit 75)
[351] John Zinc, Flare Systems, http://www.johnzink.com/wp-content/uploads/flar_SYSTEMS1.pdf (Commenter's Exhibit 76); John Zinc, Refining & Petrochemical Flares, p. 10, http://www.johnzink.com/wp-content/uploads/refiningpetrochemical-flares.pdf (Commenter's Exhibit 77); Charles E. Baukal, Jr. (Ed.), The John Zink Combustion Handbook, CRC Press, New York, 2001, pp. 241, 622-623 (Commenter's Exhibit 78); Stone and others, Chapter 7, Flares, http://www.gasflare.org/pdf/Flare_Type.pdf; Callidus Technologies, Flares, http://www.premac.co/pdf/Callidus_Flare.pdf. (Commenter's Exhibit 79)

obtained with a lower Btu content gas, such as raw syngas, due to isolation from wind effects. An enclosed flare, for example, includes the John Zinc ZTOF system, which encloses the flame in a refractory lined combustion chamber, effectively eliminating any visible emissions. No thermal radiation is emitted, contrary to the Project Summary's claim. In addition to providing a non-visible flame without thermal radiation, the ZTOF significantly reduces noise levels, again contrary to the unsupported claim in the Application. Full-load noise of less than 85 dBA adjacent to the flare is typical. Special acoustical wind fences can achieve 70-75 dBA. These flares can burn anywhere from a few hundred pounds per hour to as high as several hundred thousand pounds per hour.[352]

Enclosed ground flares are not appropriate for the TEC. The decision to use an elevated flare, rather than an enclosed ground flare, depends on a number of factors. Flares are often elevated to avoid the possibility of nearby ignition sources and minimize objectionable noise, heat, and odors in the working environment. Flares are also elevated for other practical reasons primarily including process gas flow rate capacity, process gas flow rate variability, and overall design complexity of an enclosed ground flare system including multiple ground flares. Enclosed ground flares generally have much lower capacities than open elevated flares and are typically used at landfills to control low volume, continuous, constant flow vent streams (as opposed to the high flow, variable streams at the TEC).[353] Because the maximum capacity of individual ground flares is far less than that of elevated flares, to accommodate the maximum design flow rate for the TEC, a number ground flares.

Enclosed ground level flares also can result in poor dispersion of combustion products near the ground which may pose a health hazard to workers, especially in the event of losing a stable flame within the complex network of burner tips typically included in an enclosed ground flare. During stable meteorological conditions with low wind speeds, the plumes from enclosed ground flares may be trapped near ground level further exacerbating the problem of poor dispersion posed by ground level sources with short stacks. Elevated flares are by far the most common type of flare used to control emissions from startups, shutdowns, and malfunctions at coal gasification facilities. CCG has indicated that it is not aware of ground flares being employed or proposed for controlling emissions from process gas generated during SSM events at any gasification facility. In addition, the comment did not identify any such facilities that use ground flares.

Although the comment did not provide a citation for the reference to the 98.5% DRE proposed as BACT for a refinery in the BAAQMD, this statement apparently relies on BAAQMD BACT guidelines dating back to 1995 and a staff report issued in 2003 in conjunction with the proposed *Regulation 12, Rule 11: Flare Monitoring at Petroleum Refineries*.[354][355] The BAAQMD BACT guideline indicates enclosed ground flares may

---

[352] John Zinc, Zink Thermal Oxidizer Flare, http://www.johnzink.com/wp-content/uploads/zink-thermal-oxidizer.pdf. (Commenter's Exhibit 80)

[353] **USEPA, Clean Air Technology Center, Air Pollution Technology Fact Sheet - Flare, Research Triangle Park, North Carolina, July 2003, available at http://www.epa.gov/ttn/catc/products.html**

[354] **BAAQMD, BACT Guideline, Section 3: Petroleum Industry, Flare-Refinery, June 30, 1995, available at http://hank.baaqmd.gov/pmt/bactworkbook/default.htm**

[355] **BAAQMD, Proposed Regulation 12, Rule 11: Flare Monitoring at Petroleum Refineries, Draft Staff Report, March 2003, available at http://hank.baaqmd.gov/pln/ruledev/12-11/2003/1211_sr_march2003.pdf**

be a technically feasible/cost effective control option for petroleum refineries, but the only flare design option which has been achieved in practice is an elevated flare. None of the refineries in Illinois use enclosed ground flares to control emissions from refinery process gas venting. In addition, CCG has indicated that none of the five refineries in the BAAQMD have enclosed ground flares.

Pursuant to the California Environmental Quality Act (CEQA), the BAAQMD prepared this staff report to summarize the findings of an initial study to determine the potential environmental impacts of proposed Regulation 12, Rule 11. This proposed BAAQMD rule would require refineries to monitor the volume and composition of gases burned in refinery flares, to calculate flare emissions based on this data, to determine the reasons for flaring, and to report certain information to the BAAQMD. The staff report contains 41 pages, yet has only has two references to ground flares. The reference presumably cited by the comment states the following with respected to flare DRE:

> **Within the District, a new emission source or a modified existing source must meet the District's New Source Review (NSR) requirements. The NSR program requires the use of Best Available Control Technology (BACT) for new or modified sources that have the potential to emit 10 pounds per day or more of VOC, carbon monoxide, oxides of nitrogen, particulate matter, or sulfur dioxide. For flares, BACT requires a control efficiency of 98% for elevated flares and 98.5% for ground flares. Other permit conditions are imposed on some flares. These conditions may include throughput limits and record keeping to document compliance.**
>
> **The proposed rule would require continuous monitoring for volume and sampling or the use of continuous analyzers for vent gas composition. Recording of video images of flares would be required. Monthly reports of flow, composition, and other data would be required. For larger releases (over 1.2 million standard cubic feet per day), a report on the time, cause, duration, and reason for the flaring would be required.**

The staff report contains no citations or references to support the 98.5% DRE for ground flares that would allow the IEPA to discern whether this control effectiveness is applicable to process gas combustion at a coal gasification facility. Without more information about the process gases associated with the claim of 98.5% control efficiency for enclosed flares, there is no way to determine whether this would be transferable to or achievable at the TEC. In no way does this lone statement indicate that multiple enclosed ground flares are a superior control option to a single elevated flare for a gasification facility, particularly as TEC is required to have a flare designed to achieve at least 98% DRE for CO and VOM and 99% for methanol and methane.

The comment makes the following incorrect statement regarding the use of ground flares at the TEC: "a single enclosed ground flare could readily accept a maximum gasifier startup flare gas flow." As shown in Table C-3.7 of Appendix C to Volume 1 of the Application, the maximum process gas flow to the flare during a single gasifier

startup is 8.73 million scf/hr. Using the appropriate molar volume conversion factor (379.5 lbmol/scf, at 1 atm and 60 °F) and the molecular weight of the raw syngas (19.3 lb/lbmol), the maximum volumetric flow rate of raw syngas to the flare during a single gasifier startup equates to a mass flow rate of 443,976 lb/hr. The actual capacity of a single John Zink ZTOF enclosed ground flare is not "several hundred thousand pounds an hour" as the comment suggests, but, based on a review of the reference cited in the comment, is actually only 6,000 scfm (360,000 scfh and approximately 15,200 lb/hr based on the molecular weight of methane which is the main constituent of landfill gas).[356] Based on this corrected capacity, CCG would need more than 24 individual enclosed ground flares to accommodate the process gas generated by a single gasifier during a startup. Similarly, the flare selection flow chart provided by John Zink referenced by this comment, clearly shows that the ZTOF system is not appropriate for the TEC. [357] John Zink is a leading flare manufacturer internationally and the selection criteria that it has established for enclosed ground flares should be representative of the selection criteria that any flare manufacturer would use.

Since enclosed ground flares can clearly be eliminated on the basis of availability and/or technical infeasibility, the unsupported costs presented by comment for an enclosed ground flare are not relevant to TEC's flare BACT determination. Even assuming a single enclosed ground flare was a feasible control option, the comment's costs are misleading for several reasons and do not demonstrate this hypothetical control option would be cost effective. With a cost per enclosed ground flare that is between 2 and 3.3 times higher than an elevated flare, this control option would not be cost effective considering the negligible increase in control efficiency that the comment claims is achievable (0.5% DRE). Based on the example provided by the comment of an enclosed ground flare capable of receiving 100 ton/hr of process gas and using the costs and anticipated DRE for enclosed ground flares and elevated flares cited by the comment, the cost effectiveness for reducing CO emissions of installing a single ground flare to replace a single elevated flare would be:[358]

- **Controlled CO Emissions from Enclosed Ground Flares: Based on the uncontrolled off-specification process gas CO emissions provided in Section C-3 of Appendix C to Volume 1 of the Application and using a 98.5% DRE, the controlled annual potential CO emissions from the enclosed ground flare would be 183.2 tpy [i.e., (1,559 tpy from cold plant startup + 1,022 tpy for total plant shutdown + 3,990 tpy for single gasifier startups + 5,641 tpy for single gasifier shutdowns) = 12,211 tpy x (1-98.5%) = 183.2 tpy].**
- **Controlled CO Emissions from an Elevated Flare: Based on the same uncontrolled potential CO emissions and a 98% DRE, the controlled annual potential CO**

---

[356] **http://www.johnzink.com/products/landfill-biogas/ztof%C2%AE-enclosed-flare/**

[357] **TEC must dispose of a waste process gas. There is no acceptable or available use for the off-specification process gas that must be flared so a flare gas recovery system is not feasible. The waste gas is not biogas. The heating value of the off-specification process gas is greater than 200 Btu/scf. Smokeless burning is required. The process gas pressure is high. Ample space is not available for an unenclosed ground flare, and the flow rate of process gas is not continuous. These criteria would require an elevated LRGO2 flare. The ZTOF enclosed ground flare is only suitable for low pressure process gas, and is therefore not even applicable to the process gas streams generated at the TEC.**

[358] **The uncontrolled CO emissions from flare during startup and shutdown events is more than 250 times higher than the uncontrolled VOC emissions during these same events, so the annualized control cost of reducing CO emissions using an enclosed ground flare is much more likely to be cost effective than annualized control cost of reducing VOC emissions.**

emissions from an elevated flare would be 244.2 tpy [i.e., 12,211 tpy x (1-98%) = 244.2 tpy].

- **Reduction in CO Emissions from an Enclosed Ground Flare: The reduction in emissions achievable with a ground flare is 61.1 tpy [i.e., 244.2 - 183.2 = 61.1 tpy].**
- **Cost Effectiveness: The smallest cost difference between an enclosed ground flare and an elevated flare cited by this comment is $2 million. On an annualized basis, this increase in capital cost equates to $219,600 [i.e., $2 million x 0.1098 capital recovery factor[359] = $219,600]. In conjunction with the CO emissions reduction, this annualized control cost equates to $3,596 per ton CO removed [i.e., $219,600 / 61.1 tpy = $3,596/ ton CO removed]. Based on the SCAQMD cost effectiveness thresholds referenced by this comment, which it recommends should be used for the TEC, the control cost for installing an enclosed ground flare to reduce CO emissions from the TEC's flare is more than 10 times higher than the $300/ton SCAQMD cost effectiveness threshold.**

If this same analysis were duplicated for VOM emissions, the annual control cost would be more than $900,000 per ton of VOM removed which is an order of magnitude higher than the $10,000/ton cost effectiveness threshold recommended by the comment in other comments. Even this overly simplified and grossly conservative cost estimate for using enclosed ground flares at the TEC, demonstrates that it is not a cost effective control option for CO and VOM emissions from the flare at the TEC. In fact, a recently issued BACT determination by BAAQMD for the No. 50 Crude Unit flare at the Tesoro refinery concluded that the cost for installing an enclosed ground flare was $98,500 per ton of VOC removed based on a cost of $44 million.[360]

While the previous discussion demonstrates enclosed ground flares are not a practical control option for the TEC, based on both technical feasibility and cost, the comment makes several additional errors in references to information available on enclosed ground flares. First, the comment cites the San Joaquin Valley Air Pollution Control District (SJVAQMD) Rule 4311 as setting a more stringent VOC emission limit for enclosed ground flares (0.0013 lb/mmBtu) than the "VOC emission rate assumed for the elevated flare" at the TEC (0.0054 lb/mmBtu).[361] The SJVAQMD enclosed ground flare limit is included in Rule 4311, but this limit does not apply to any refineries in the SJVAQMD. A September 2008 BACT determination for a new flare at Big West's refinery in the SJVAQMD concluded an enclosed ground flare was not a feasible control option for reducing VOC emissions from the proposed flare. Big West held discussions with the multiple vendors regarding the suitability of enclosed ground flares for the refinery, and SJVAQMD summarized these discussions as follows:

> **The applicant discussed flaring requirements with Bekart, a provider of enclosed burners that are being offered as a potentially "cleaner" alternative to traditional flares, and John Zink and Callidus, who offer enclosed ground level**

---

[359] **USEPA, Air Pollution Control Cost Manual - Sixth Edition (EPA 452/B-02-001), Section 3 VOC Control, Section 3.2 VOC Destruction Controls, Chapter 1 – Flares, September 2000, available at http://www.epa.gov/ttn/catc/products.html.**

[360] **BAAQMD, Permit Evaluation and Statement of Basis for Renewal of Major Facility Review Permit for Tesoro Marketing Company Facility # B2578 and B2579, May 24, 2010, pg. 310.**

[361] **Sierra Club/Natural Resources Defense Council, Comments, January 3, 2012, pg. 78. fn. 242.**

flares. Bekart indicated that the enclosed burner they offer would not be a good choice, as it is not well suited for emergency flaring and that up to 15 individual units would be required to accommodate the Clean Fuels Project flaring requirements. John Zink and Callidus have confirmed that the enclosed, ground level flares that they offer are not expected to have any better performance or lower emissions of VOC or NOx than the non-enclosed flares they offer. In fact, Callidus indicated that enclosed flares are expected to have higher combustion temperatures and higher NOx emissions than non-enclosed flares. As with the Bekart enclosed burner, the enclosed, ground level flares from either John Zink or Callidus are not ideally suited for burning emergency releases of gas, and given the project's projected flaring requirements, several individual enclosed, ground level flares would be required.[362]

While the comment's stated total VOC emission rate from the TEC's flare of 0.0054 lb/mmBtu is incorrect, the VOC emission rates do exceed the SJVAQMD Rule 4311 limit. To achieve compliance with the SJVAQMD VOC limit for enclosed ground flares based on the low heating value of TEC's process gases, the enclosed ground flare would need to have a DRE of more than 99.3%, which is much higher than 98.5% The comment's claim is achievable citing BAAQMD .[363] The comment pointed to nothing supporting that such a high DRE would be achievable, so the only option for TEC to comply with the provisions of the SJVAQMD would be to use an elevated flare which does not have strict emission limits in Rule 4311. The elevated flare requirements in Rule 4311 include a flare minimization plan and various monitoring, recordkeeping, and reporting requirements which are similar to the requirements for the TEC's flare in the permit. Rule 4311 does not require the use of enclosed ground flares, but if they are used, it establishes emission limits and testing requirements for VOC or NO_X.

The comment's final reference to enclosed ground flares is a USEPA document entitled *Benefits of an Enclosed Gob Well Flare Design for Underground Coal Mines*. This document contains data which further supports the conclusion that enclosed ground flares are not practical for the TEC. First, the maximum flow rate of gob gas (methane in air vented at atmospheric pressure from underground coal mines) to an enclosed ground flare referenced by USPEA is 2 million scfd or 83,000 scfh. At this capacity, more than 100 enclosed ground flares would be necessary to control the process gas from a single gasifier startup. Second, USEPA states that "one of the biggest drawbacks of the enclosed flare is cost" and "the total cost of a complete installed enclosed flare system is approximately twice that of the open flare. Operation and maintenance of the enclosed flare is also marginally higher than the open flare (Table 2)." These observations based on a review of the USEPA gob well enclosed flare study support the determinations in the application regarding the availability and feasibility of enclosed ground flares for the proposed plant.

BACT WAS NOT REQUIRED FOR THE POWER BLOCK

---

[362] **SJVAPCD, Authorization to Construct Application Review for Big West of California, LLC, September 3, 2008, pg. 136.**

[363] **Uncontrolled VOC emission rate from the TEC flare during a cold plant startup is 0.185 lb/mmBtu (i.e., 0.0037 lb/mmBtu /(1 - 98% DRE) = 0.185 lb/mmBtu). At a controlled VOC emission rate for a enclosed ground flare, the DRE would be 99.3% (i.e., 1.0 - 0.0013 lb/mmBtu/0.185 lb/mmBtu = 99.3%).**

78. The limit in the Draft Permit for NOx emissions from the combustion turbines in the power block is not BACT. The power block will generate electricity from two combined cycle combustion turbines. It is expected that one turbine will operate as a baseload unit and the second as an intermediate load unit. The intermediate load unit would run depending upon relative revenue from generating electricity versus selling SNG. The application concludes that BACT for nitrogen oxides ("NO_x") during normal operation is a NO_x limit of 2 ppm at 15% O_2 based on a 3-hour rolling average, achieved using selective catalytic reduction ("SCR").[364] The top-down BACT analysis does not contain any support for these choices, such as a conventional ranking or hierarchy table,[365] supported by stack tests, other permit limits, vendor literature, etc. The limit simply appears.[366] In fact, the record contains no evidence that IEPA considered any other emission limit save the unsupported limit put forth by the applicant as BACT. The NSR Manual requires that "the most-effective control option not eliminated in step 4 is selected as BACT."[367] There is no evidence that the proposed BACT limit is the most-effective control option. Certain information in the application indicates that it is not. In this regard, I agree with the technology choice of SCR and the numerical value of the BACT limit, 2 ppm at 15% O_2, but disagree that a 3-hour rolling average satisfies BACT.[368] Neither the application nor the Project Summary provides any basis for the selection of a 3-hour rolling average rather than a more stringent 1-hour average.

The averaging time is part of the BACT determination.[369] For a set value for an emission limit, the shorter the averaging time, the more stringent the emission limit. CCG must demonstrate that the BACT limit is the emission rate based on the maximum degree of reduction that is achievable. This demonstration has not been made and, in fact, is refuted by information in the record. Appendix D of the application summarizes BACT determinations for other similar facilities. This summary includes 36 BACT determinations for NO_x for similar gas turbines at 2 ppm. Of these, 14 are based on a 1-hour averaging time.[370] There are also other similar facilities have been permitted with a NOx emissions limit of 2 ppm at 15% O_2 and a 1-hour averaging time. The application does not explain why these more stringent BACT determinations for similar turbines firing natural gas are not NOx BACT for the turbines at the TEC.

Regardless, a 1-hour averaging time must be established to protect short-term ambient standards, in particular the 1-hour nitrogen dioxide ("NO_2") NAAQS.[371] The modeling made specific assumptions about the maximum NO_x emissions that occur during any one hour period to demonstrate compliance with this standard. Thus, there must be a 1-hour limit in the permit to protect the NAAQS, either the BACT limit or another 1-hour limit. The Draft Permit contains no 1-hour limits on emissions of NO_2 from the gas turbines. The

[364] Ap., v. 1, p. 7-4 and Project Summary, p. 41.
[365] NSR Manual, Sec. IV.C.3 and Table B-2.
[366] *See*, e.g., Ap., p. *7-5*.
[367] NSR Manual, p. B.53.
[368] The averaging time is the time period over which a limit is averaged. A 3-hour rolling average averages the data in 3-hour chunks, moving forward 1-hour at a time. A moving average smoothes out short-term fluctuations in the data. The shorter the averaging time, the more stringent the emission limit as there is less time to average out short-term spikes.
[369] NSR Manual, p. B.56.
[370] Ap., v. 1, Appx. D, Table D-3, pp. D-26 to D-28.
[371] *See, e.g.*, NSR Manual, p. B.56; *In re Mississippi Lime*, slip op. at 42.

separate startup and shutdown limits discussed later in my comments are not based on a 1-hour average but rather are expressed on a per-event basis. The Draft Permit does not limit the duration of these events, but the Application indicates that the expected duration of a cold start, which has the highest emissions, is 2.4 hours.[372]

A 3-hour average can mask shorter-term emission spikes that would violate the 1-hour NO_x NAAQS. A 3-hour average, for example, would allow all of the emissions to occur during one hour, effectively tripling the mass emission rate assumed in the 1-hour modeling. This type of event is hidden by a BACT limit based on a 3-hour average. Thus, the averaging time for the BACT limit must be no longer than the shortest NAAQS averaging time, which is 1 hour for NOx.[373]

Consistent with of the NSR Manual, Section IV.C.3, A table ranking the control efficiency of all technically feasible NO_X control options is provided in Table 7-2 of the Application. This table lists technically feasible control options and ranks the options from the control efficiency that would result in the lowest emission rate to the control efficiency that would result in the highest emission rate. The comment indicates there is no evidence that the proposed BACT limit is the most-effective control option" but goes on to state that it agrees with the technology choice, i.e., SCR, and the numeric BACT limit, 2 ppm at 15% O_2. As SCR was selected as BACT, the application shows that the most effective control option was selected, as the ranking provided in Table 7-2 clearly indicates that SCR achieves the highest level of control. Furthermore, since the comment states agreement with the technology choice and the numeric portion of the BACT limit, there is no need to provide further justification that SCR is the best performing control option for the TEC. The proposed BACT limit is based on the turbine vendor's estimates for the uncontrolled NO_X emission rate from the turbines based on extensive experience designing and testing modern F-class turbines, paired with the anticipated performance of the proposed SCR under normal steady-state operation (defined as CT loads at or above 60%).

With respect to the BACT emission limit, an appropriate averaging period is certainly important. The NOx BACT limit of 2 ppm at 15% O2 is based on a 3-hour rolling average to address variability that may occur during a single hour. Moreover, as compared to the Draft Permit, in the issued permit, the 2 ppm limit for NOx would also apply during malfunctions. The 3-hour averaging period is appropriate to enable upsets and malfunctions that would otherwise result in exceedances to be corrected in accordance with good air pollution control practice, avoiding shutdowns and subsequent startups that might otherwise be necessary with a 1-hour averaging period and leading to higher emissions. In this regard, the 3-hour averaging period provides for more consistent operation of the turbines, as is desirable for consistent operation of the associated emission controls.[374, 375]

---

[372] Ap.,c. 1,pp.7-14 to 7-15.

[373] *See, e.g., In re Mississippi Lime Company, slip op. at 42-45; In re NMU slip op. at 50-51.*

[374] **When setting NOx limits for combustion turbines under NSPS Subpart GG and NSPS Subpart KKKK, USEPA determined that averaging times longer than one hour were appropriate and adopted standards for combined cycle turbines based on 4-hour and 30-day rolling averages (40 CFR 60.334(j)(1)(iii)(A) and 40 CFR 60.4350(h). respectively.) There is not a regulatory requirement that a BACT emission limit must be selected with the shortest possible averaging time.).**

In addition to the 2 ppm BACT limit, the permit includes BACT limits in lb/event for startup and shutdown events.[376] As emissions during startup and shutdown are higher than emissions during other normal operations, these BACT limits (specifically, the limit for cold startup events) were used in the modeling to demonstrate compliance with the 1-hr NO2 NAAQS. CCG demonstrated compliance with the 1-hour NO_2 NAAQS based on a cold startup scenario NOx emission rate of 184.8 pounds per hour.[377] This emission rate was calculated based on the cold startup emission rate indicated in the application and listed in the permit, as well as the corresponding event durations in the application. The definitions of startup and shutdown were included in the issued permit.

It is also noteworthy that compliance with the pound per event emission limit will ensure compliance with the 1-hour NO_2 standard, even without an hourly NO_2 emission limit. The "cause and contribute analysis" in Section 5.3.1 of Volume II of the application indicates that the maximum 1-hour NO_2 impacts were dominated by low level releases from units other than the turbines (i.e., the fire pump engines at the plant and nine natural gas-fired compressor engines at an existing source operated by Natural Gas Pipeline Of America's (NGPA)).[378] The plant-wide impacts can easily accommodate variability in NOx emissions from the combustion turbines over a 3-hour time period without exceeding the 1-hour NO_2 NAAQS. With regard to the comment's suggestion that a 3-hour average could allow all of the emissions to occur during one hour, effectively tripling the mass emission rate assumed in the 1-hour modeling, the maximum turbine emission rate at which CCG demonstrated compliance with the 1-hour NO_2 NAAQS was the cold startup scenario emission rate of 184.8 pounds per hour, well over three times the 16.14 pound per hour emission rate modeled for normal operation at 100% load. This cold startup modeling case provides more than ample assurance that any variability in the 1-hour NOx emission rate during normal steady-state operation at or above 60% load that may be seen over a 3-hour averaging period will not negatively impact compliance with the 1-hr NO_2 NAAQS.

In addition, as discussed on page 7-1 of the GHG BACT evaluation for the power block in Volume 3 of the Application, CCG states its intention to operate one combustion turbine as a baseload unit and the second combustion turbine as an intermediate load unit that will cycle on and off (up to 232 hr/yr combined for startups and shutdowns, refer to Section C-8 of Appendix C to Volume 1 of the application) based on an assessment of the relative revenue from power generation and sale of SNG. Despite this intended dispatch for the combustion turbines, CCG conservatively assumed in the

---

[375] **In this regard, as observed by this comment, "similar" facilities have been permitted with a NOx emission limit of 2 ppm at 15% O_2, 1-hour averaging, and, due to the case-by-case nature of BACT determinations, other "similar" facilities have been permitted with a NOx emission limit of 2 ppm at 15% O_2, with an averaging period greater than 1-hour. Moreover, many of the facilities in this second group were permitted more recently than those facilities identified by this comment and after the promulgation of the final 1-hr NO_2 NAAQS in April 2010. Table 1 below provides a list of similar facilities with NO_X emission limits based on averaging periods greater than 1-hour.**

[376] **Limits with shorter averaging periods are now necessary for protection of the 1-hr NO_2 NAAQS than had previously been required with the annual NO_2 NAAQS. However, NAAQS compliance demonstrations and BACT analyses can be addressed as separate aspects of the PSD permitting process, in which case BACT limits may be set to address the performance of emission control technology and other permit limits may be set to protect air quality. In this regard, for combustion turbines, modeling emission limits are established on a mass basis for protection of air quality, while BACT emission limits are often concentration or heat input rate based limits determined on a case-by-case basis using the most stringent control option available that is technically and economically feasible.**

[377] **Application Volume II, Appendix B, Table B-2.1, page B-5.**

[378] **Application Volume II, page 5-9 of Section 5.3.1.**

1-hr NO_2 NAAQS modeling that both turbines would operate as intermediate load units. Based on this assumption, CCG modeled the worst-case hourly emissions from turbine cold startups assuming both turbines started up in the same hour and assuming that the turbines were operated continuously in a cold startup mode throughout all hours of each year in the 5-year meteorological dataset used in the modeling. If USEPA's current guidance were followed, intermittent combustion turbine startup and shutdown emissions would not need to be addressed in the NAAQS modeling since they are not expected to "occur frequently enough to contribute significantly to the annual distribution of daily maximum 1-hour" actual impacts from the turbines. Therefore, CCG's 1-hr NO_2 NAAQS analysis likely significantly overpredicted impacts from the TEC as compared to the results of an analysis following current USEPA guidance.[379]

79. The Draft Permit fails to satisfy BACT for Startup and shutdown of the combustion turbines. Condition 4.2.2 of the draft permit would exempt startups, shutdowns, and malfunctions from BACT limits for NOx, CO, VOM, and CO_2. Separate limits are set in Condition 4.2.6(a) (Attachment 1, Table I) for startups and shutdowns. The draft permit is silent as to BACT for malfunctions. However, this table does not identify these limits as BACT limits or as satisfying BACT. The Project Summary at 55 suggests these are BACT limits,[380] but the application does not contain a BACT analysis for them, rather only an unsupported assertion that they are BACT.

---

[379] **Furthermore, recent 1-hr NO_2 NAAQS guidance from USEPA suggests that the approach utilized by CCG to demonstrate compliance with the NAAQS was extremely conservative in that it assumed maximum hourly NOx emissions from intermittent sources like the firewater pump engines and startup/shutdown events from the combustion turbines would occur continuously. The 1-hr NO_2 NAAQS modeling conducted by CCG for the TEC was completed prior to the issuance of USEPA's March 1, 2011 guidance document entitled *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hr NO_2 National Ambient Air Quality Standard*.[379] The following statements by USEPA in this guidance memo clearly indicate that peak 1-hr NO_2 emissions from intermittent operating modes of units like emergency generator engines, firewater pump engines, and baseload power plants do not need to be considered in NAAQS analyses and thus, do not require modeling-based emission limits to ensure compliance with the NAAQS. "EPA's guidance in Table 8-2 of Appendix W involves a degree of conservatism in the modeling assumptions for demonstrating compliance with the NAAQS by recommending the use of maximum allowable emissions, which represents emission levels that the facility could, and might reasonably be expected to, achieve if a PSD permit is granted. However, the intermittent nature of the actual emissions associated with emergency generators and startup/shutdown in many cases, when coupled with the probabilistic form of the standard, could result in modeled impacts being significantly higher than actual impacts would realistically be expected to be for these emission scenarios. The potential overestimation in these cases results from the implicit assumption that worst-case emissions will coincide with worst-case meteorological conditions based on the specific hours on specific days of each of the years associated with the modeled design value based on the form of the hourly standard...Given the implications of the probabilistic form of the 1-hour NO_2 NAAQS discussed above, we are concerned that assuming continuous operations for intermittent emissions would effectively impose an additional level of stringency beyond that intended by the level of the standard itself. As a result, we feel that it would be inappropriate to implement the 1-hour NO_2 standard in such a manner and recommend that compliance demonstrations for the 1-hour NO_2 NAAQS be based on emission scenarios that can logically be assumed to be relatively continuous or which occur frequently enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations...We recognize that case-specific issues and factors may arise that affect the application of this guidance, and that not all facilities required to demonstrate compliance with the 1-hour NO_2 NAAQS will fit within the scenario described above with clearly defined continuous/normal operations vs. intermittent/infrequent emissions. For example, a large baseload power plant may experience startup/shutdown events on a relatively infrequent basis whereas as a peaking unit may go through much more frequent startup/shutdown cycles. It may be appropriate to apply this guidance in the former case, but not the latter."**

Under this USEPA guidance, CCG would not have modeled the two firewater pump engines at their peak hourly emissions, but rather would have modeled only weekly readiness testing emissions (similar to the approach used for the emergency generator engines), or alternatively, the annual potential emissions averaged over the number of hours in a year as recommended in USEPA's guidance document. Furthermore, if intermittent units are not required to be considered in 1-hr NO_2 NAAQS modeling because of the low likelihood of causing or contributing to violations of the probabilistic NAAQS on an actual impacts basis, then permitting authorities are not required to establish modeling-based 1-hr emission limits for these types of units.

[380] Project Summary, p. 55 ("The BACT limits for periods of startup and shutdown which are expressed in pounds per event, are also imposed to protect air quality. They set a cap or ceiling on allowed emissions, consistent with USEPA guidance for setting BACT for periods of startup, shutdown and malfunction.")

The application justifies setting these separate limits "in order for CCG to propose limits that are both "achievable" and keep the CCCTs under a high degree of control during normal steady-state operation..."[381] However, the origin of these "secondary BACT limits" is unknown. There is no information on how they were derived, *e.g.*, through a top-down BACT process, to avoid exceeding air quality standards, as turbine vendor guarantees, etc. They are simply stated as permit conditions with no support.

Periods of startup and shutdown are part of normal operating procedure. As such, they must be included in the BACT analysis. *See, e.g., In re Tallmadge Generating Station,* PSD Appeal No. 02-12, slip op. at 24 (EAB May 21, 2003) ("BACT requirements cannot be waived or otherwise ignored during periods of startup and shutdown."); *In re Louisville Gas & Electric Co.*, slip op. at 10 (Sept. 10, 2008) ("A PSD BACT limit must apply at all times, unless the permitting authority determines the need to establish alternative BACT limits for periods of startup or shutdown, and justifies such limits as part of a complete BACT analysis.")[382]

Exemption of a source "from any *concentration* limits during startup and shutdown," including short-term limits, is "potentially a... serious concern."[383] An applicant cannot avoid BACT emission limits during periods of startup and shutdown through weak and improper secondary limits.

There is no evidence in the record that these startup and shutdown limits are BACT limits, which must represent the maximum degree of reduction achievable at all levels of operation, as indicated by the requirement that the limits be met on a continual basis. If an applicant is seeking secondary limits for startup/shutdown, certain demonstrations must be made and a specific process must be followed in setting such secondary limits as set out below.

As required with all BACT limits, IEPA must provide an explanation of how it arrived at the limits. Here, the limits provided for startup/shutdown are completely arbitrary because there is no explanation how they were determined. There is no linkage between the limit set, the relevant control equipment, the extent to which they will be operational during startup and shutdown, and the degree to which it will effectively control for the relevant pollutant. There must be a discussion regarding each piece of control equipment that identifies its relevant design parameters, their limitations, the pollutants impacted, and accommodations of those limitations. The Draft Permit does not meet these BACT requirements because there is no discussion relating to startup and shutdown sequence for any of the control equipment, *i.e.*, the low NOx combustors and the SCRs. For each of these pieces of control equipment the Draft Permit is deficient because it does not provide the following:

The comment incorrectly concludes that the draft permit "exempts startups, shutdowns, and malfunctions" from BACT limits for NOx, CO, VOM, and CO_2.[384] The

[381] Ap., v. 1, p. 7-14.
[382] *See also* Memorandum from John B. Rasnic, USEPA Stationary Source Compliance Division, to Linda M. Murphy, USEPA, Region 1, Automatic or Blanket Exemptions for Excess Emissions During Startup, and Shutdowns Under PSD (January 28, 1993) ("Rasnic 1993 Memorandum") (Commenter's Exhibit 81); Memorandum from Kathleen M. Bennett to Regional Administrators, Re: Policy on Excess Emissions During Startup, Shutdown, Maintenance, and Malfunctions, (Feb. 15, 1983) ("Bennett 1983 Memorandum") (Commenter's Exhibit 82). I note that BACT covers periods of so-called malfunction to the extent that the malfunction could have been anticipated and avoided through proper maintenance.
[383] *In re Indeck-Niles Energy Center, PSD Appeal No. 04-01, 13 E.A.D. 126*, 170-181 (E.A.B. Sept. 27, 2006).
[384] **Comments from Sierra Club and National Resources Defense Council, January 3, 2012, page 81.**

draft permit is not exempting these scenarios from BACT. On the contrary, the draft permit provides different BACT limits for different operating conditions, consistent with the statutory and regulatory requirements for BACT. The draft permit provides secondary BACT limits for startup and shutdown periods in Attachment 1, Table of the draft permit. As discussed in the application, permitting with separate secondary limits for these periods is consistent with what has been proposed and accepted for other power generating facilities.[385] This approach is appropriate here given that combined cycle turbines using dry low-NOx combustion technology and equipped with SCR are being addressed, as further discussed below. The permit further requires implementation of a startup, shutdown and malfunction plan for the power block. (Condition 4.2.5-2) that requires the source to minimize emissions during startup, shutdown and malfunction events.

The comment goes on to state that the origin of the secondary BACT limits proposed in the application is unknown. However, table footnotes in Volume I of the application clearly states that startup and shutdown emission rates were provided by the manufacturer.[386] For combustion turbine, emissions data from the vendor is generally the best available source of emissions data for emissions during startup and shutdown periods and establishment of secondary BACT. Due to the transient and site-specific nature of emissions and efficiency of control devices during these periods, establishing startup/shutdown BACT emission limits through direct comparison to startup and shutdown BACT limits for other facilities is not appropriate.

As the comment suggests that periods of startup and shutdown are part of normal operating procedure and must be included in the BACT analysis, they were. As a consequence, secondary BACT limits are included in the permit to address startup and shutdown periods. However, while startup and shutdown are routine phases in operation of the turbines, they are not "normal operation" of the turbine because of the transitional operating condition during these periods. As such the BACT limits for "normal operation" are not transferable to these periods, nor do similar BACT limits have to be established for such periods. In this regard, the IEPA does not agree with the comment's assertion that concentration based limits are needed during startup and shutdown periods as a consequence of the decisions in the Indeck-Niles Energy Center PSD Appeal No. 04-01.[387], [388]

---

[385] For example, for Prairie State Generating Company (Peabody), outside Marissa, Illinois, certain modes of operation were permitted with secondary BACT limits. This permit, issued April 24, 2005 by the IEPA, was reviewed by the EAB. The EAB did not dispute the use "secondary" BACT limits, stating that "…adoption of an alternative method during these periods [startup and shutdowns] "reflects Illinois EPA's experience with industrial boilers, which found that the rate-based compliance methodology of the NSPS* is problematic when applied to stringent BACT limits. IEPA stated further that, "[w]ithout this provision for an alternative compliance methodology, the BACT limits for SO_2 and NOx could not be extended with the necessary confidence that compliance is reasonably achievable with the BACT limits." *Reference from quoted material states: "The Permit uses the NSPS's methodology as the primary method for determining compliance with the BACT limits at issue during periods that do not include startup or shutdown."
Section II.C.2 of PSD Appeals No. 05-05 (pages 118-119), decided August 24, 2006.
Although this statement referred only to SO_2 and NOx limits, the EAB concurred with the IEPA's decision on lb/hr startup/shutdown BACT limits for CO, were also addressed in Section II.C.3 of the EAB's decision.

[386] Application Volume I, Appendix C, Table C-8.2, footnote 1, page C-36, and Application Volume III, Appendix A, Table A-5.2, footnote 1, p. A-20.

[387] *In re Indeck Niles Energy Center,* PSD Appeal No. 04-01, (E.A.B. September 30, 2004).

[388] Furthermore, the cited appeal does not support argument made in the comment. Although the referenced footnote in this appeal indicates that the lack of concentration limits during startup and shutdown is potentially a concern in this particular case, a lack of concentration based startup and shutdown emission limits was not raised as an issue during the appeal; therefore, no decision was made by EAB to indicate

The comment also requests an explanation of how the IEPA arrived at the startup and shutdown BACT limits. These limits were established from data supplied in the application. CCG has confirmed that it obtained this data from the vendor, who considered HRSG/steam turbine heat load requirements for these periods based on the following factors:

- **During startup, the combustors operate in diffusion flame mode until approximately 50-60 percent load, when they changeover to lean premix mode.**
- **During shutdown, the combustors changeover from lean premix mode to diffusion flame mode at approximately 50-60 percent load.**
- **During startup, ammonia may not be introduced into the SCR until the turbine exhaust gas temperature uniformly reaches approximately 550 °F, which occurs towards the end of the startup sequence when the turbines have been switched to lean premix mode.**
- **During shutdown, ammonia is no longer introduced into the SCR once the turbine exhaust gas temperature falls below approximately 550 °F, which occurs towards the beginning of the shutdown sequence prior to switching to diffusion flame mode.**

As shown above, both the combustor operating mode and temperature in the SCR play an important role in emissions during startup and shutdown periods. While the inability to use the SCR initially is part of the reason for higher emissions, the higher pre-control emissions generated under these conditions is also an important factor.[389]

---

that concentration based limits were in any way required. Furthermore, this editorial comment made by EAB with regard to the startup and shutdown BACT limits at the Indeck-Niles Energy Center is not applicable to the TEC, as there is a significant difference between the startup and shutdown BACT limits proposed in these cases. In this regard, it is noteworthy the EAB approved startup and shutdown limits that were not concentration-based in the later Peabody Prairie State case, a decision which was two years after the Indeck-Niles decision.

[389] More detail regarding the basis of startup and shutdown emissions and control device efficiency follows in response to the four specific areas of identified by the comment.

(i) A list of key design parameters that affect the control device and its efficiency;

SCR operation and efficiency is affected by the turbine exhaust gas temperature reaching the SCR catalyst, the SCR catalyst temperature, the ammonia vaporizer system temperature, the length of time required for startup and shutdown sequences, the level of NOx emissions and the split between NO and NO_2 entering the SCR, and the exhaust gas flow rate. These parameters were identified in Section 7.7 of Volume I of the TEC permit application. (Application Volume I, Section 7.7, pp. 7-13 through 7-14.)

DLN combustor efficiency is affected by the operating mode of the combustor. The combustors operate in diffusion mode at low loads (e.g., <50 percent load) and in a premixed mode at higher loads. Once in lean premixed mode, the fuel is injected in the premixer, and combustion air is mixed with fuel in premix tubes. The air and fuel mixture then enters the combustion zone, where low NOx combustion occurs.* Until the lean premixed mode is reached, the combustors will emit NOx at levels comparable to those of higher emitting diffusion flame turbines, which contributes most significantly to the need for separate emission limits during startup periods. Similarly, at the beginning of shutdown, the turbines are switched from lean premixed mode to diffusion mode, resulting in increased NOx emissions during shutdown periods.

*** For further information, review to U.S. Department of Energy, National Energy Technology Laboratory. *The Gas Turbine Handbook*. 2006, Chapter 3.2.1.2-5, page 218. http://www.netl.doe.gov/technologies/coalpower/turbines/refshelf/handbook/3.2.1.2.pdf.**

(ii) How these key design parameters vary or change during startup and shutdown;

A detailed description of changes in design parameters for combined cycle turbines during startup are provided in "Issues Related to Gas Turbine Startup Emissions" presented in the Journal of EUEC, Volume I. The first turbine is ramped up through a series of speed and load conditions from a state of no fuel input to normal operating conditions with fuel supplied at full rates. During this ramp-up period, the HRSG, steam drums, steam turbine, steam piping, and control equipment are heated to normal operating temperatures using a controlled process specified by the equipment manufacturers to reduce thermal stress and avoid equipment damage. Typically, one turbine is ramped up in stages to a state of full speed no load and is then maintained in a low load state (20-30%) until the turbine, HRSG, and steam system have reached the specified temperatures. The turbine then continues to ramp up load in diffusion flame mode until changeover to lean premix combustion mode.* This generally occurs near 50-60 percent load, depending upon the turbine. Ammonia is introduced to the SCR at the end of the startup sequence, once it reaches a uniform minimum temperature of approximately 550 °F. Therefore, the SCR does not provide any control until the end of the startup sequence when the turbine is in lean premix mode.

During shutdown, the gas turbine is switched from lean premix mode to diffusion mode and ramped down to a state of no load and ultimately shut off. The ammonia feed to the SCR is shut off prior to cooling the catalyst to allow time for all of the remaining ammonia to be reacted or purged from the catalyst. Therefore, the SCR provides minimal control during the shutdown sequence.

*** For further information refer to "Issues Related to Gas Turbine Startup Emissions." *Journal of EUEC*, Volume 1, 2007. Available at http://www.euec.com/getattachment/euecjournal/Paper_3.pdf.aspx.**

(iii) Critical levels of each of the design parameters, below or above which, the device cannot be operated without damage:

The comment concludes with the following statement: "Without following this process and including such a discussion, the secondary limits do not meet BACT requirements." However, further information to support the secondary BACT, as potentially sought by this final comment, is not necessary. As explained, due to the nature of startup and shutdown, emissions from the turbines are greater and the control technology that is normally present is not effective. It is not possible to pinpoint precise emission rates, exact times when controls become effective, or precise descriptions of how design parameters vary during startup and shutdown sequences. These will likely vary depending upon ambient conditions, as they affect the temperature and moisture content of combustion air. They will also be affected by the procedures recommended by the vendor, which may evolve over time based on operational experience with these turbines and similar turbines at other facilities. The analysis presented by CCG is consistent with other approved startup and shutdown BACT determinations and is adequate to support the determination of BACT for these turbines for these periods.

80. All feasible control options were not considered for the combustion turbines. Conditions 4.2.2(d) and 4.2.5-1(c) in the Draft Permit would require that the "secondary BACT limits" be achieved using "good air pollution control practices" without explaining what this means or why other more effective controls were not selected. There is no evidence in the record demonstrating that IEPA considered ways to eliminate or reduce excess emission during startup and shutdown to meet compliance obligations under the CAA.[390]

The plan that would presumably address these options, the "startup, shutdown, and malfunction plan" required by Condition 4.2.5-2 would be submitted in the future. This plan is outside of the four corners of the permit and therefore is not enforceable. Further, it is not available to the public and will be developed after the permitting process, therefore violating public participation requirements.

CCG and the IEPA failed to consider ways to reduce emissions during startup and shutdown as part of the permitting record.[391] It is feasible, for example, to preheat the SCR catalyst using an auxiliary boiler to allow NOx control before 60% operation.

The pollutants for which secondary BACT limits are set are NOx, CO, VOM, and CO_2e. As demonstrated in Section 7 of the application, the selected controls for these pollutants are SCR with dry-low NOx burners for NOx, good combustion controls for CO and VOM, and turbine design with firing of SNG or natural gas (i.e., not firing cleaned syngas). Conditions 4.2.2(d), 4.2.5-1 and 4.2.5-2 and Attachment 1, Table I provide for short term secondary BACT limits, annual BACT limits, and startup and

---

The transient nature of the turbine operation and its interaction with the downstream HRSG and steam turbine components make it infeasible to define critical levels of the combustion design parameters until the system has been fully designed.
(iv) Options for how the design of the control device can accommodate a wider range of safe and effective operations:
SCRs are well understood within the electric power industry and are optimized to be as effective as possible over a wide range of operating conditions. CCG is not aware of any available control device alternatives to allow SCR operation over a wider range of conditions. Further, as previously stated, SCR design is only one factor contributing to emissions from the turbines during startup and shutdown periods, and higher pre-control emissions generated under these conditions are equally if not more important. It is in CCG's best interest to minimize overall NOx emissions as well as startup and shutdown durations due to USEPA's Clean Air Markets Division trading programs, which together will result in good faith efforts to minimize NOx emissions during startup and shutdown periods.

[390] *See, In re* Tallmadge Generating Station, slip op., pp. 26-27.

[391] *See In re RockGen Energy Center*, 8 E.A.D., p. 553.

shutdown operating requirements and require a startup/shutdown and malfunction plan. There is evidence in the record showing consideration of ways to eliminate or reduce emissions during startup and shutdown, as required by the Clean Air Act. The decision in *In re Tallmadge Generating Station*, slip op., pp. 26-27), as cited in this comment is not as applicable to the TEC, due to distinctly different circumstances that are present. That case dealt with a permit that would have completely exempted the permittee from complying with BACT and other emission limits during startup and shutdown events as long as a plan, approved by the permit issuer, was prepared to minimize emissions during those events.[392] As previously stated, the permit for the TEC contains both short-term and long-term BACT limits, as well as a requirement to develop startup/shutdown operating procedures. In addition, the EAB's decision with regard to PSD Appeal No. 04-01 *In re Indeck-Niles Energy Center* supports rejection of this reference. "Since Indeck's PSD permit does not completely exempt startup/shutdown from BACT limitations, the basis for invoking *Tallmadge* and *RockGen* must be declined." [393] Therefore, *Tallmadge* is not applicable to the TEC.

The comment also expressed concern that the startup and shutdown plan required by Condition 4.2.5-2 would be "outside of the four corners of the permit and therefore is not enforceable." This is because this plan "is not available and will be developed after the permitting process, therefore violating public participation requirements." This plan, in conjunction with the permit's other enforceable terms and limits applicable to the turbines, will effectively ensure that these emission units remain in compliance and operate in accordance with good air pollution control practice. Startup and shutdown procedures are necessarily based, to a large degree, on manufacturer specifications. Since facilities typically have not purchased specific equipment prior to issuance of a permit, as a practical matter the detailed information necessary for preparation of this plan is not available for inclusion in the application or draft permit. Condition 4.2.5-2(c)(i) instead specifies that this plan shall be developed prior to initial startup of the combustion turbines. The plan is considered a required element of operating practices for the turbines, thus the public has the opportunity to review the plan, including any amendments, upon its completion (Condition 4.2.5-2(c)(ii)). This is consistent with the approach taken by other permitting agencies ((*see e.g.*, Power Holdings PSD Permit at 17; Hydrogen Energy California PSD Draft Permit at 133) and expressly approved by the EAB. *See, e.g., In re Indeck-Niles Energy Center*, PSD Appeal No. 04-01 (EAB Sept. 30, 2004) (upholding permit that contained SSM limits where elements to be included in an SSM plan were set forth); *see also In re Power Holdings of Illinois, LLC*, PSD Appeal No. 09-04, slip op. (EAB 2010) (same for Flare Minimization Plan). As discussed in *In re Indeck-Niles Energy Center*, "when delineating the contours of such a plan during the permit-writing phase, i.e., before construction has commenced, the permit writer's task is circumscribed by the fact that many of the plan's details will not be knowable until the facility is actually constructed and put into an operational mode."[394] The combination of short-term and long-term BACT limits for startup and shutdown and a detailed framework for a startup, shutdown, and malfunction plan

[392] *In re Tallmadge Generating Station*, PSD Appeal No. 02-12, pages 26-27.
[393] *In re Indeck Niles Energy Center,* PSD Appeal No. 04-01, (E.A.B. September 30, 2004). p. 15.
[394] *In re Indeck Niles Energy Center,* PSD Appeal No. 04-01, (E.A.B. September 30, 2004). Page 17.

adequately satisfy BACT for these periods. The EAB's decision in the *Indeck - Niles Energy Center* Appeal No. 04-01 supports this conclusion.

Ways to reduce emissions during startup and shutdown were considered. The result of this consideration is directly reflected in the permit, as it requires CCG "to operate and maintain all emission units at this plant, including associated air pollution control equipment, in a manner consistent with good air pollution control practice" and to "at all times, including periods of startup, shutdown, malfunction or breakdown, operate as practicable to minimize emissions (Condition 3.6)." Furthermore, the SSM plan provided for in the permit is not the same as the SSMP plan rejected by the EAB for the RockGen facility. *See In re RockGen Energy Center*. The RockGen permit exempted startup and shutdown from the BACT limits in the permit instead relying solely on a plan that could be developed up to 4 months after initial operation of the facility. By contrast, the permit for the TEC includes numeric BACT limits applicable during startup, shutdown and malfunction with the related plan serving as a means to further reduce emissions, not relax established emission limits. (*See* Condition 4.2.5-2).

The suggestion that the auxiliary boiler be used to preheat the SCR to allow NOx control before 60% load is purely theoretical and patently impractical. The IEPA is not aware of this technique in practice and CCG has confirmed that it is not aware of it ever being used for combined cycle applications. Initializing operation of the SCR catalyst system primarily depends on the temperature of the SCR catalyst, temperature of the ammonia vaporizer system, and temperature of the combustion turbine exhaust gas passing through the catalyst. Use of the auxiliary boiler, by presumably injecting steam or heated air into the HRSG, is not a feasible means of uniformly warming the catalyst. The use of the auxiliary boiler will also consume fuel which, in turn, will generate emissions of the very same pollutants the comment is proposing to be decreased by its use. Moreover, it is in CCG self-interest to minimize the duration of startups and shutdowns, while fulfilling vendor recommendations for operation during these periods so as to maintain equipment guarantees. This is because turbine operation during these periods is inefficient, with only small amounts of power generated relative to the amount of fuel is being consumed.

The comment inappropriately focuses on just SCR catalyst operation during startup when there are other contributing factors that influence NOx emissions during these events. Turbine operation during startup periods results in higher NOx emissions not only because the SCR catalyst is not up to temperature but also because the turbine combustors do not operate in dry-low NOx (DLN) mode. Even with a preheated SCR, the turbines would be unable to achieve the proposed BACT emission rates for normal steady-state operation due to the lack of DLN combustion. Second, the energy content or enthalpy of the steam from the auxiliary boiler, which would have a capacity less than 300 mmBtu/hr based on the relevant considerations for its sizing, would not be sufficient to heat the SCR catalyst to the needed reaction temperature given its small size relative to the combustion turbine exhaust gas flow rate and temperature. Even if the SCR catalyst was preheated, once the combustion turbine exhaust gas was fed through the SCR, the catalyst temperature would immediately be reduced to the equilibrium temperature determined by the relatively cool high flow rate turbine

exhaust gases generated at loads below 60%, thus eliminating any benefit in terms of NOx control efficiency that the preheating may have initially achieved. Third, operation of the auxiliary boiler to reduce startup emissions is not cost effective, even with the assumptions that: 1) the SCR would achieve a 90% SCR control efficiency, which is well above the feasible control efficiency in these scenarios, 2) the auxiliary boiler would only operate one hour per hour of startup for the combustion turbines, which is an underestimate, and 3) the auxiliary boiler size is sufficient to heat the SCR catalyst, which is not the case. A brief cost analysis, assuming the approach could be implemented and including only natural gas costs for the auxiliary boiler and excluding the additional operating costs for the SCR associated with the additional hours of operation as compared to the base case indicates the cost-effectiveness of this approach would be in excess of $40,000/ton of NOx. This is clearly excessive, further confirming that preheating of the SCR is a viable BACT control option.[395]

81. The averaging time and duration of the startup and shutdown events covered by these limits are not stated. Even assuming they are BACT limits, the limits are incomplete as they include no averaging time. This is critical, for example, for pollutants with NAAQS and PSD increments with 1-hour averaging times, such as the NAAQS for NO_2, SO_2, and CO.

The startup and shutdown emission limits do not include an averaging time as the actual time over which the limit will apply will vary based on the actual duration of a startup or shutdown event. Expressing a startup and shutdown limit in this way inherently limits the total quantity of emissions during a startup and shutdown event and requires CCG to conform to the preliminary startup/shutdown procedures that were the basis of the emission limits. An alternate 1-hour average lb/hr limit that applies during startup and shutdown would on the other hand allow CCG to emit at the worst-case rate expected for a startup or shutdown for an unspecified duration as

[395] **Auxiliary Boiler SCR Preheat Cost Analysis:**

Cost Information		
Aux Boiler Heat Input	279	MMBtu/hr
Industrial Price of Natural Gas	$7.15	per MMBtu
Annual Hours of SU Events	142	hrs/yr
Annual Natural Gas Cost	$282,388	dollars
Emissions Information		
Turbine SU Uncontrolled NO_X	7.58	tpy
Assumed Control Efficiency	90%	
Turbine SU Tons of NO_X Removed	6.82	tpy
Aux Boiler NO_X during Turbine SU	0.21	tpy
Tons of NO_X Removed less Aux Boiler NO_X	6.61	tpy
Control Cost		
Control Cost per Ton NO_X Removed	$42,750.78	dollars/ton

Cost Information		
Aux Boiler Heat Input	279	MMBtu/hr
Industrial Price of Natural Gas	$7.15	per MMBtu
Annual Hours of SU Events	142	hrs/yr
Annual Natural Gas Cost	$282,388	dollars
Emissions Information		
Turbine SU Uncontrolled NO_X	7.58	tpy
Assumed Control Efficiency	90%	
Turbine SU Tons of NO_X Removed	6.82	tpy
Aux Boiler NO_X during Turbine SU	0.21	tpy
Tons of NO_X Removed less Aux Boiler NO_X	6.61	tpy
Control Cost		
Control Cost per Ton NO_X Removed	$42,750.78	dollars/ton

Assumes that the auxiliary boiler could preheat one SCR at a time. Natural gas price based on average industrial price in Illinois in 2010 assuming a heating value of 1,000 mmBtu/million scf. Available at http://www.eia.gov/dnav/ng/ng_pri_sum_dcu_sil_a.htm.

long as the CCG could continue to demonstrate compliance with the annual emission limits for the turbines. To ensure that CCG cannot claim the turbines are in startup or shutdown mode beyond the expected durations provided in the application, the startup and shutdown definitions provided in the footnote to Attachment 2 Table 2 of the Project Summary have been included in the issued permit. The use of 1-hour average startup/shutdown limits is not supported in this particular case, as the emissions vary throughout the duration of the startup and shutdown events, and 1-hour average emission limits based on the worst-case hourly emission rate during startup and shutdown events would be less stringent than emission limits averaged over the duration of the events, and, given the effective stack height of the turbines, such limits are not needed to protect air quality.

BACT WAS NOT REQUIRED FOR EQUIPMENT LEAKS

82. Emissions from equipment leaks can be controlled by eliminating them at the source with leakless components, such as welded connectors. They can also be reduced by using various leak detection and repair ("LDAR") programs that monitor each component or group of components for leaks and repair them when found. The application evaluated several technically feasible control options for equipment leaks using the top-down BACT process.

The application concluded that leakless components would not be cost-effective for any components in any service. The Application also concluded that an LDAR or other monitoring program was not cost-effective for any component or groups of components that it evaluated. These conclusions are based on numerous erroneous assumptions, which, when untangled, reveal that the top technology is in fact cost-effective for all components in all services, except heavy liquid service. Instead, CCG proposed to implement a "MACT-equivalent" LDAR program for components in high VOM or H_2S service without performing a cost analysis.[396] This proposed program addresses about 15% (3,664) of the roughly 25,000 components. CCG also proposed implementing good work practices, the least effective option, for all components, also without performing a cost analysis as it claimed it was infeasible to estimate performance.[397]

While emissions from equipment leak components can be reduced through control technologies such as leakless components or LDAR programs, the BACT analysis demonstrated that leakless components were not cost effective. It also showed that unlike components in regular VOM service, LDAR is not cost effective for components on low VOM process streams. LDAR is proposed as BACT for all regular VOM process streams, as the top remaining control technology. As noted by the comment, the BACT determination results in LDAR control for only approximately 15% of the components. Selection of an LDAR program as the BACT level control option for reducing VOM emissions from ELC on regular VOM process streams is appropriate (as discussed elsewhere), and this selected control option is included in the required by the permit through the LDAR requirements (see Conditions 4.9.6 to 4.9.9).

[396] Ap., v. 1, Sec. 6.6, p. 6.48 to 6-51.
[397] Ap., v. 1, Sec. 6.6, p. 6-49.

For all equipment leak components in low VOM service, the only feasible control option for reducing CO and VOM emissions from ELC identified in the detailed, top-down BACT analysis presented in the application is good work practices. "Good work practices" are also required by the permit through the work practice required by Conditions 4.9.2(b) and 4.9.7(b). Although periodic AVO checks performed as part of implementing good work practices can reduce emissions by up to 30%, CCG conservatively assumed emissions from all low VOM service components were uncontrolled.[398] Even at uncontrolled rates, the annual potential VOM emissions from ELC in low VOM service (i.e., 1.14 tpy) are very small as compared to the annual potential uncontrolled VOM emissions from organic chemical manufacturing facilities (i.e., 66 tpy on average for continuous chemical manufacturing plants).[399] [400] In the comment's own words, the BACT emissions levels are "very tiny."

The comment also includes a copy of Table 6-2 from Volume 1 of the Application, acknowledging the control effectiveness evaluation conducted as part of the top-down BACT analysis for ELC. In a previous comment, this commenter claims that the TEC application included "no support or analysis" for the PRV BACT determination; however, in this comment it provides an example of such support as it refers to Table 13 of the application.

Although the comment now acknowledges the top-down BACT evaluation conducted for ELC, it questions certain conclusions within the analysis including: 1) The determination that leakless components are not cost effective, and 2) The determination that applying a facility-wide LDAR program is not cost effective. Instead, the comment claims that leakless components are cost effective and should be chosen as BACT for all components except those in heavy liquid service. However, the comment does not identify flaws in ELC control cost analyses for leakless components and the facility-wide LDAR program presented in the Application that result in a conclusion that such components are cost-effective. Rather, the commenter's revised control cost analysis is in fact flawed and not credible.

83. All feasible controls were not analyzed for equipment leaks. The key first step in a BACT analysis is to ensure that all potential control options are identified. As the EAB has explained, the goal at this step is to cast as wide a net as possible so that a "comprehensive list of control options" is compiled. *In re Knauf* 8 E.A.D. at 130. The application mentioned LDAR programs in passing but did not explain what they are, how they work, or the factors that determine their effectiveness. Instead, it eliminated plant-wide LDAR based on a cost-effectiveness analysis assuming a "HON-equivalent LDAR program," without ever explaining what that means. The application should have considered a range of LDAR programs that includes the most-effective to satisfy BACT. Some of the additional controls that should be evaluated are discussed below.

---

[398] ***Commonwealth of Kentucky Division of Air Quality Permit Statement of Basis (Draft)*, for Kentucky Syngas, LLC, dated December 11, 2009; p. 89. Cited as footnote 67 in Volume 1 of the TEC application.**

[399] **Sum of uncontrolled VOM emission rates for components in low VOM service not controlled by LDAR is 1.14 tpy, as determined by the potential emissions data in Sections C-24 to C-27 of Appendix C to Volume 1 of the Application.**

[400] **Alpha Gamma Technologies, New Source MACT Floors for Batch and Continuous Chemical Manufacturing Processes Covered by the MON, Attachment 10, Estimated Impacts Associated with LDAR Control Requirements of the MACT Floor Regulatory Option, June 7, 1999 available at www.regulations.gov.**

Contrary to this comment's assertion, Exhibit 391-7 in the application contains the exact LDAR program CCG proposed for inclusion in the permit, which identifies the fundamental principles behind the proposed LDAR program. Additionally, the TCEQ equipment leak permitting guidance document, upon which the ELC emission calculation methodology and LDAR program for the TEC are based,[401] was referenced extensively throughout the application and was available in the permit record; it provides a complete description of the principles behind an LDAR program and how such a program achieves reductions in emissions of air pollution.

The comment goes on to claim that the term "HON-equivalent LDAR program" was never defined in the application. The term "HON-equivalent LDAR program" is used in the footnotes to Section D-2 of Appendix D to Volume 1 of the Application to describe the basis of the facility-wide LDAR cost calculations. In the context of the main reference document utilized in the LDAR program control cost calculations entitled *MACT Floor, Regulatory Alternatives, and Nationwide Impacts for Equipment Leaks at Chemical Manufacturing Facilities* (referenced in Tables D-2.1 and D-2.2), it is clear that a HON-equivalent LDAR program refers to a LDAR program implemented in accordance with NESHAP Subpart H. As described in footnote 11 to the cost calculations in Section D-2 of Appendix D to Volume 1 of the Application, the LDAR control credits used to determine the emission reductions that were achievable by implementing a facility-wide LDAR program were taken from the 28VHP and 28CNTQ control credits in the TCEQ equipment leak permitting guidance[402] to ensure consistency with the controlled potential emission calculations for components in high-VOM components. Through earlier comments that have already been responded to, the comment directly references the basis for the LDAR program evaluated, citing TCEQ's equipment leak guidance document and the specified LDAR requirements under the 28VHP and 28CNTQ LDAR programs. In addition to providing the base reference for this LDAR program, CCG included the detailed requirements of the proposed LDAR program, consistent with 28VHP as Exhibit 391-7 to the 391-CAAPP application form in Appendix A to Volume 1. As discussed previously, the LDAR program selected for the TEC is in all cases equally stringent or more stringent than the HON, so it is appropriate to rely on the TCEQ's LDAR control credits associated with the proposed LDAR program in conjunction with cost estimates from implementing a HON-equivalent LDAR program to determine the annual control cost of implementing a facility-wide LDAR program. Contrary to the comment's assertion, CCG fully described the requirements of the LDAR program evaluated as BACT, as well as provided necessary documentation of the corresponding control credits that could be achieved through the implementation of this LDAR program (see Section C-24 to C-27 of Appendix C to Volume 1 of the Application).

The "HON-equivalent LDAR program" presented in the BACT evaluation, patterned after the stringent 28VHP program from TCEQ represents the most effective program to satisfy BACT. USEPA has previously made determinations that LDAR requirements under HON are representative of BACT:

---

[401] **TCEQ, Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000, Draft.**
[402] **See page 52 of the TCEQ Technical Guidance.**

…compliance with an equipment leak control program (equipment modifications, and leak detection and repair) equivalent to the Hazardous Organic National (HON) Emission Standards for Hazardous Air Pollutants (40 CFR Part 63 Subpart H) would generally represent BACT.[403]

The comment's suggestion that a range of LDAR programs are more effective is incorrect, for the specific reasons discussed in the following responses.

84. A more Effective LDAR Program should be required as BACT. The most basic elements of an LDAR program are the definition of a leak (expressed as parts per million of the leaked substance), the frequency of monitoring, and the timeline in which leaks are repaired once discovered. The Bay Area Air Quality Management District ("BAAQMD") has demonstrated that stricter regulation is feasible than contemplated in the BACT analysis or required in the Draft Permit.

The BAAQMD supervises LDAR programs at 5 refineries with over 200,000 regulated components, as well as chemical plants, bulk plants, and bulk terminals under Regulation 8, Rule 18 (Reg 8-18). This regulation, first adopted in 1998, sets lower leak limits, more frequent inspections, and shorter repair schedules than evaluated in the BACT analysis or ultimately required as "MACT-like" LDAR in the Draft Permit, as shown in the Table 14, provided with my comment. For example, the leak definition for valves in gas/vapor/light liquid service is 100 ppm, with quarterly/annual inspection frequencies, compared to the Condition 4.9.6(a) of the Draft Permit, which would set the leak definition at 500 ppm, with monthly/annual inspection frequencies. Another key aspect of an LDAR program is the scope of any exemptions recognized by the program. The LDAR program evaluated in the BACT analysis exempts leaks that are "unsafe" or "difficult" to monitor. The BAAQMD rule does not recognize such an exemption, as it is not consistent with BACT, given the BAAQMD's experience. The BACT analysis must include all feasible LDAR programs, including one as effective as is currently in use within the BAAQMD.

In particular, in order to avoid the need to monitor such unsafe equipment leaks, components that qualify for difficult or unsafe to monitor or repair should be required to use leakless designs. This should be cost-effective as (1) the cost of monitoring, repairing and re-monitoring devices that are difficult to monitor is substantially higher than components in more convenient locations and (2) the potential emissions from leaking "inaccessible" components is greater since a leak is less likely to be observed visually or by sense of smell and instrumented monitoring only occurs annually.

The BACT analysis also did not consider requiring that "repeat offenders" be replaced. The South Coast Air Quality Management District and the Ventura County Air Pollution Control District each have rules under which components that have been subject to repair more than,

[403] **Memorandum from John S. Seitz to Air Division Directors "BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Sulfur Refinery Projects," January 19, 2001. (EPA-HQ-OAR-2007-0751-0001), available at http://www.epa.gov/ttn/caaa/t1/memoranda/bactguid.pdf.**

e.g., 5 times within a year be replaced with BACT/BARCT or be vented to an approved air pollution control device.[404]

Finally, IEPA must ensure the integrity of any LDAR program. As USEPA's history of enforcement actions demonstrates, this integrity cannot be taken for granted.[405] The USEPA has encountered significant fraud in the conduct of LDAR inspections and in the reporting of results.[406] To avoid this, IEPA must include safeguards in the Permit, including requiring a professional engineer to sign off on all LDAR reports. IEPA must also explore requiring periodic independent audits of LDAR programs, at least for the largest emitters.

The basic criteria that define an LDAR program both in terms of the level of stringency and the potential emissions reductions that are achievable were described by the comment as: the leak definition, the monitoring frequency, and the required repair timeline for identified leaks. Based on these three basic criteria, the comment asserts that the LDAR program required as BACT for the TEC is less stringent than LDAR programs defined in local regulations elsewhere in the country. The comment specifically references the BAAQMD and SCAQMD as having more stringent LDAR programs with aspects that should be incorporated into the permit for the TEC.

The comment claims that the Draft Permit should implement the LDAR programs in the BAAQMD or SCAQMD is misguided. Although the comment presents these nonattainment LDAR programs as "more effective" LDAR programs, they offer no support to demonstrate how these programs would be more effective. According to the 2006 proposed HON rule, USEPA rejected the lower leak definition (<500 ppm) for valves for two reasons: (1) a lack of data to suggest lowering the valve leak standard below 500 ppm would reduce emissions or risks, and (2) a similar lack of data to support the assumption that Method 21 can validly detect leaks at such a low level.[407]

USEPA has specifically evaluated BAAQMD Rule 8-18 and determined that the leak rate definition is not more stringent than the HON, and thus not more stringent than the LDAR program included in the permit, which has leak definitions that are equal to or lower than HON. Furthermore, the LDAR requirements set as BACT in the permit are based on the same quarterly monitoring frequency (Condition 4.9.6(g)) as these nonattainment LDAR programs. The monitoring frequency will be of comparable stringency between the TEC's LDAR program and BAAQMD Rule 8-18.

---

[404] *See,* SCAQMD Rule 1173(g)(3) and Ventura County APCD Rule 74.7. Under the Ventura County rule, for example, if a valve is found to have suffered 5 major leaks in a year it shall be replaced by a valve with a bellows seal, or with graphite, PTE or PTFE stack chevron seal rings, or with BACT technology level components.

[405] For a more recent example, *see* USEPA's recent refinery settlements. *See, e.g* http://www.epa.gov/compliance/resources/cases/civil/caa/oil/index.html. (Commenter's Exhibit 83)

[406] In the late 1990's, EPA discovered flagrant, industry-wide violations of several CAA requirements at the nation's refineries. Among the most significant violations were LDAR rules violations where refiners, and independent contractors hired by refiners, routinely underreported by up to a factor of 10 the number of leaking valves, leading to significant excess emissions. The ensuing enforcement actions led to 29 settlements with operators over 90% of the refining capacity in the country. These settlements required improved LDAR practices, $82 million in fines, and $75 million in Supplemental Environmental Projects. This experience demonstrates a need for detailed independent oversight of LDAR activities, as does the recent Pelican refinery criminal prosecution.

[407] 71 FR 34434, National Emissions Standards for Hazardous Air Pollutants for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry, Proposed Rule, June 14, 2006.

The quoted repair schedule presented in Commenter's Table 14 is also misleading. TEC's LDAR program and the BAAQMD rule do not provide for a direct comparison. For example, the comment insinuates that the BAAQMD-required repair schedule (within 7 days) and re-inspection requirements (within 24 hours of repair/replacement) are more stringent than the requirements of the Draft Permit which only requires repairs to be made and re-inspection to be completed within 15 days [Condition 4.9.6(f)]. However, the permit includes a more stringent first attempt at a repair for valves, pumps, and connectors (within 5 days) than the final repair deadline in BAAQMD Rule 8-18 [Condition 4.9.6(h)]. If the first attempt at repair is successful in eliminating the leak, the components at the TEC would be repaired more quickly than under the BAAQMD LDAR program.

Furthermore, TEC's LDAR program requires that gas or hydraulic testing of new and reworked piping connections be performed prior to returning the component to service [Condition 4.9.6(b)]. This repair verification is a stringent measure required to provide another level of certainty that the repaired component will not leak within 24 hours after being put back into service. In these situations, dictating another re-inspection within 24 hours would be unnecessary. The BAAQMD rules do not require gas or hydraulic testing.

Even as an example of a candidate LDAR program, the requirements of BAAQMD do not meet the definition of BACT in certain instances. For example, the BAAQMD LDAR program contains an allowance for "Non-repairable Equipment" that affords up to five years prior to requiring ELCs to be repaired.[408] This exemption from the repair requirements in the LDAR program lessens the overall stringency as compared to the requirements in permit. The repair requirements of the permit are encompassing and do not include any exemptions except for delay of repair provisions which are not the same as the non-repairable equipment exclusion in the BAAQMD LDAR program. Condition 4.9.6(i) states that "every reasonable effort shall be made to repair a leaking component within 15 days." Furthermore, BAAQMD's non-applicable LDAR program also provides for "Alternate Compliance", which exacerbates the issue of drawing direct comparisons between selected elements of the BAAQMD LDAR program and TEC's LDAR program.[409]

The comment states in reference to Condition 4.9.6(a) of the Draft Permit "The LDAR program evaluated in the BACT analysis exempts leaks that are 'unsafe' or 'difficult' to monitor." Nowhere does the permit exempt leaks from "unsafe" or "difficult" to monitor components. In fact, the cited permit condition specifically provides "If an "unsafe-to-monitor" (as defined in 40 CFR 63.168(h)) component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe-to-monitor times," and "A "difficult-to-monitor" (as defined in 40 CFR 63.168(i)) component for which quarterly monitoring is specified may instead be monitored annually." In contrast to the comment's misrepresentation, the permit specifically includes "unsafe" and "difficult" to monitor components under the LDAR program, only setting alternative monitoring frequencies. Condition 4.9.6(a) also provides that

[408] **BAAQMD Rule 8-18-306.1.**
[409] **BAAQMD Rule 8-18-308.**

"to the extent that good engineering practice will permit, new and reworked valves and piping connections shall be located to be reasonably accessible for leak-checking during plant operation."

The permit requires all components to be accessible for the LDAR monitoring program, where possible. Due to the nature of the processes employed at TEC, which will include vessels that operate at high temperature and pressure that will need to be able to isolated from other process equipment, it may not be possible to have all components easily accessible. As such, the permit reasonably addresses these other components by requiring that unsafe-to-monitor and difficult-to-monitor components be inspected at least annually (or as soon as possible during safe-to-monitor times).

Furthermore, these provisions in the LDAR requirements of the Draft Permit are analogous to specific provisions of even the nonattainment-based LDAR programs used by BAAQMD and SCAQMD. The comment claims that "the BAAQMD rule does not recognize such an exemption, as it is not consistent with BACT, given the BAAQMD's experience."[410] BAAQMD's Rule 8-18 is not BACT, but a nonattainment regulation. Even so, BAAQMD provides similar monitoring relaxation to the LDAR requirements of the Draft Permit, requiring that inaccessible valves and pressure relief devices only be inspected annually (see 8-18-401.3). The SCAQMD takes the relaxation one step further, and specifically exempts unsafe-to-monitor components from routine inspections:

> **(l) Exemptions**
>
> > **(1) The provisions of this rule shall not apply to the following cases, where the person seeking the exemption shall supply the proof of the applicable criteria to the satisfaction of the Executive Officer:**
> >
> > > **(A) Components which present a safety hazard for inspection as documented and established in a safety manual or policy, previously, or with the prior written approval of the Executive Officer except that the operator shall monitor these components for leaks when it is safe to do so. Upon detection of a leak, the operator shall repair or replace the component(s) as soon as the repairs or replacement can be carried out safely.[411]**

Following the comparison to BAAQMD, the comment somehow concludes that leakless components would be cost effective for unsafe to monitor equipment locations. CCG evaluated the annualized control cost of installing and operating leakless components and determined they were not cost effective in any situation. This determination was not based on an incremental cost effectiveness based on controlled emissions from implementing an LDAR program, but reflected a conservative estimate of cost per ton of pollution abated, assuming leakless components controlled 100% of the uncontrolled potential emissions. A response to the comment's inaccurate assessment that the

[410] **Sierra Club/Natural Resources Defense Council, Comments, January 3, 2012, pg. 86.**
[411] **SCAQMD Rule 1173(l)(1)(A).**

potential emissions from "inaccessible" components would be higher than estimated was previously provided. Leakless components would be no more cost effective for difficult to monitor components than elsewhere, as already demonstrated through the top-down BACT evaluation.

In regards to "repeat offenders", the comment cites the SCAQMD requirement which is a unique program, tailored specifically to meet the demands of the local extreme ozone nonattainment designation of its respective air shed. SCAQMD's requirements have not been recognized by the USEPA as a viable option for the rest of the country. Regardless, the issued permit has ELC BACT limits which will require CCG to essentially do what would be required by the SCAQMD rule but with measurable results.

The comment's final suggestion directs the IEPA's attention to USEPA's recent enforcement actions against refineries for LDAR violations and alleges that CCG would submit fraudulent LDAR reports unless they are signed by a professional engineer. The comment does not identify how a professional engineer certification on LDAR reports eliminates fraud, or provides any additional pollution mitigation. Operating permits pursuant to Title V of the Clean Air Act, as will be applicable for the TEC, already require a Responsible Official to certify compliance. As such, appropriate accountability will already be provided for the TEC.

85. Additional leak monitoring Methods must be reviewed as part of the BACT analysis. The USEPA runs a program to help industrial sources identify and implement best practices for reduction of methane emissions, known as Natural Gas Star.[412] Several of the recommended technologies and practices[413] may be applicable to equipment leaks. For instance, one project describes the use of optical imaging in a directed inspection and maintenance program. Handheld infrared cameras are used to identify, in real time, process components that are leaking.[414] Additional imaging technologies, including the use of DIAL (Differential Absorption Light Detection and Ranging), can also be used to identify fugitive sources of VOCs.[415] The existing LDAR program could be expanded to process units not currently covered (*e.g.*, cooling towers).[416] "Smart" LDAR programs are also being implemented as a means of minimizing fugitive process losses. These options must be evaluated as a part of a complete BACT analysis for fugitive VOC emissions from flanges.

Optical scanning programs can be a part of an overall improved LDAR program. Use of optical cameras involves some modest level of investment; however, once purchased, these devices can provide an extremely low cost means of filling the gaps in the LDAR program.

---

[412] USEPA, Natural Gas Star; http://www.eya.gov/gasstar/index.html.
[413] USEPA, Natural Gas Star, Recommended Technologies and Practices; http://www.epa.gov/gasstar/tools/recommended.html.
[414] *See, e.g.*, Technology Transfer: Optical Leak Imaging for the Hydrocarbon Industry, ICF Consulting, available at http://www.icfi.com/Markets/Environment/doc files/optical-leak-imaging.pdf. (Commenter's Exhibit 86)
[415] *See, e.g.*, Refinery Demonstration of Optical Technologies for Measurement of Fugitive Emissions and for Leak Detection, Alberta Research Council, November 2006, available at http://www.arc.ab.ca/areas-of-focus/carbon- conversion-capture-and-storage/cccs-publications-and-resources/dial-emission-reports/ (Commenter's Exhibit 87); see also Fugitive VOC-emissions measured at Oil Refineries in the Province of Vastra Gotaland in South West Sweden, 2003, available at http://www.spectrasyne.ltd.uk/ROSEVOCreport.pdf.(Commenter's Exhibit 88)
[416] CARB, Reducing Greenhouse Gas Emissions from California Refineries, April 2008, available at http://www.capcoa.org/climatechange/upload/documents/Presentation-04-1 1-2008-WorkshopPresentationRefineries4-11.pdf, (Commenter's Exhibit 27); *see also* Texas Environmental Research Consortium, Project H7-A: Compilation of Information on Cooling Towers, Equipment Fugitive Leaks and Flares, November 30, 2003. (Commenter's Exhibit 89)

Daily or weekly scans can identify plant areas containing gross emitters (including "unsafe to monitor" or "difficult to monitor" components) for targeted LDAR inspections. Such inspections could replace scheduled inspections and save operators money by detecting leaks early, while improving the environmental performance of the facility. Use of optical scanning devices, pressure relief valves, monitoring devices and other technical advances can complement existing programs. However, the suite of existing options have not demonstrated the ability to provide the level of emission reductions as can be obtained from well-designed and implemented LDAR programs. For these reasons these options must be considered in addition to and not *in lieu of* existing programs.

The comment references USEPA's Natural Gas Star program recommended technologies and practices and claim these control measures should be included in TEC's LDAR program. The Natural Gas Star Program is described by USEPA as a "flexible, voluntary partnership that encourages oil and natural gas companies – both domestically and abroad – to adopt cost-effective technologies and practices that improve operations efficiency and reduce emission of methane."[417] In addition to being voluntary, the Natural Gas Star program does not include coal gasification facilities. The comment references an optical imaging study used in a "directed inspection and maintenance program" where "handheld infrared cameras are used to identify, in real time, process components that are leaking." However, the cited reference "Optical Leak Imaging for the Hydrocarbon Industry" was not provided with the other exhibits, and the web address included in the citation is no longer accurate.

The comment also asserts that the LDAR program could be improved by additional monitoring methods, specifically optical imaging and Differential Absorption Light Detection and Ranging (DIAL). Optical sensing techniques may assist in broadly and generally identifying ambient concentrations for high level analyses and comparisons, but they are impractical for routine use in an operating facility to identify specific leaking components. The comment's suggestion that an LDAR program complemented by optical sensing would enable expansion of the program to other process units not currently covered fails to correlate this broader sweep with the accompanying benefit. These other process units were independently subjected to a complete BACT analysis. The top feasible control technology is already being utilized across the whole plant. Additional optical sensing of already well-controlled units would only add cost, without measurable benefit.

The IEPA is not aware of any facilities in Illinois that use optical sensing techniques in day-to-practice to identify leaking components. In contrast, the permit requires inspection using USEPA Method 21, which is prescribed in multiple federal LDAR programs and in the previously-referenced BAAQMD and SCAQMD nonattainment LDAR requirements. Method 21 has been extensively studied to identify anticipated effectiveness at reducing emissions, and its use is clearly reasonable and appropriate here. Furthermore, Method 21 was utilized as the basis for the SOCMI without ethylene emissions factors, and aligns the BACT limits, control program, and

[417] **USEPA, Natural Gas Star Program, http://www.epa.gov/gasstar/index.html.**

compliance demonstration methodology, maintaining a uniform basis. Furthermore, the comment provide no data to suggest that optical sensing techniques either alone or in combination with LDAR, such as Smart LDAR, would result in additional emissions reductions than already achieved by the LDAR program included in the permit.

Open path emissions measurement technologies such as DIAL are in the research and development phase. The primary repository of publicly available information from USEPA on this technology is USEPA's Office of Solid Waste and Emergency Response (OSWER) Technology Innovation Program. USEPA's *Measurement and Monitoring Technologies for the 21st Century* (21M^2) program website clearly states that the program's mission is to "research and inventory the state of the art for advanced monitoring technologies" for future commercial and regulatory deployment.[418] DIAL is listed among other open path technologies for future development along with ultra-violet differential optical absorption spectra (UV-DOAS), open path Fourier transform infrared (OP-FTIR), Raman spectroscopy, and tunable diode lasers. Thus, according to the USEPA, optical sensing technology such as DIAL is not yet a demonstrated technology that should be considered feasible for use in conjunction with a BACT limit or for selection as a BACT level control option (assuming this measurement technique could provide quantifiable VOM emission reductions). USEPA also expressed this position in the Emission Estimation Protocol for Petroleum Refineries when they state:

> **These remote sensing techniques are not yet approved by EPA as a method of quantifying emissions from equipment leaks or any other sources. Furthermore, because the measurement is conducted some distance downwind from a source, the techniques alone are not practical for identifying specific leaking equipment components. When appropriate, we will update this document to include methodologies for any optical leak imaging or other remote sensing techniques that develop to the point of being able to quantify equipment leak emissions.[419]**

The use of optical sensing techniques, such as DIAL and solar occulation flux (SOF), has been tested as a tool to identify ambient concentrations downwind of a process area or facility (in some studies at a distance of 1 kilometer from the facility). Of the few published studies, the focus is on VOC emissions from international refineries. These published studies are primarily focused on source types different from that proposed for TEC (refineries not coal gasification plants) with different emissions. Refineries have large amounts of fugitive VOC emissions from pure or nearly pure VOC process streams throughout the entire facility, and the TEC will have only small amounts of fugitive VOC emissions from ELC on a small number of VOC process streams located in very discrete areas of the plant and representing only approximately 15% of the plant-wide ELC. The refineries studied are also regulated by different agencies with different regulations (Canadian and European air agencies and not the IEPA and USEPA who must implement the requirements of the Clean Air Act and PSD program).

---

[418] **USEPA, Office of Solid Waste and Emergency Response, Technology Innovation Program, *Measurement and Monitoring Technologies for the 21st Century (21M^2)*, September 11, 2006. (http://www.clu-in.org/programs/21m2/strategy.cfm)**

[419] **RTI International, *Emission Estimation Protocol for Petroleum Refineries*, Version 2.0, September 2010, available at http://www.epa.gov/ttnchie1/efpac/protocol/index.html.**

In addition, the optical sensing techniques are sensitive to many variables and cannot distinguish in a single broad scan between emissions from plant sources and background concentrations from natural sources. As noted in a study of optical sensing techniques performed by CONCAWE Air Quality Management Group's Special Task Force on remote measurement of VOCs:

> **The two complex techniques (DIAL and SOF) have also been used to determine emissions from oil refinery area diffuse sources. Both provide values for emission flux only over short term scan periods. Although this permits the identification of the 'significant emitters', extrapolation to provide annual average emissions results in large errors….**
>
> **The use of complex optical techniques to determine the emissions from diffuse area sources (e.g. tanks) provides only short term flux data. Extrapolation of these data to provide annual emission estimates results in large errors. Moreover, although these techniques can identify a tank with significant emissions, they cannot pinpoint the equipment components causing them.[420]**

The comment suggests that optical sensing would be a technique that could be used "to identify plant areas containing gross emitters," acknowledging that in actual practice the tool is limited to only generalized evaluations. As well, optical sensing techniques are extremely sensitive to meteorological conditions requiring very expensive equipment, coordination with other monitoring equipment, and highly trained testers. The use of optical sensing techniques is impractical as an application for plant workers to use to identify specific leaking components. Optical sensing techniques cannot identify a specific leaking valve from a single measurement, as the weekly AVO inspections and quarterly monitoring in the LDAR program required by the permit would. The comment provides no data to suggest that optical sensing techniques result in additional certainty of emissions reductions than the LDAR requirements already included in the Draft Permit.

While there have been international field-proofing studies on refineries which concluded that the refinery factors in USEPA's *Protocol for Equipment Leak Emissions Estimates* may underestimate total emissions, these conclusions were narrowly based in each paper on a single refinery, for limited field-proofing scans over a very short time period (only during one month in one season – summer time), and only while the refinery was operating at maximum capacity. These studies did not re-visit the same facility at a separate time in the year, consider effects of varying loads or operating scenarios, include in the comparative data sets the broad differences from multiple refineries, nor include in the data other industry types more relevant to the TEC, such as coal gasification. These studies also would have included VOC emissions from sources located at refineries which will not be present at the TEC.

---

[420] **Optical methods for remote measurement of diffuse VOCs: their role in the quantification of annual refinery emissions (report no. 6/08), prepared by the CONCAWE Air Quality Management Group's Special Task Force on remote measurement of VOCs, June 2008, pages 39 and 40.**

An example of these extremely narrow studies and incomplete analyses leading to premature conclusions is "Direct Measurement of Fugitive Emissions of Hydrocarbons from a refinery," which was published in the Journal of the AWMA, as cited in this comment. This study was limited to a single refinery in Canada using the Spectrasyne Mobile DIAL unit for optical sensing comparisons set to measure methane, C_2+ hydrocarbons, and benzene from the tank storage, delayed coker and coker black water pond, cooling towers, and processing areas for fractionation and upgrading. These emissions and process areas are typical of a refinery producing liquid fuels, but should not be compared to the TEC coal gasification process, which does not use process streams with heavy concentrations of C_2+ hydrocarbons and benzene and does not utilize the production areas for liquid fuels that were the focus of this publication. The paper did acknowledge some of the inherent weaknesses of DIAL surveys:

> **Previous DIAL surveys performed by Spectrasyne Ltd. in Europe have demonstrated that emissions from areas of oil and gas industry plants can vary in response to operational and/or meteorological changes. For this reason, the procedure adopted by Spectrasyne was to measure each target area for 2 to 3 hr and to return to the area on at least one other occasion on a different day. (see page 1049)**
>
> **In this DIAL demonstration project, there was insufficient survey time available to measure all of the tanks under different wind speed conditions and different conditions of tank levels and level movement. (see pages 1052-1053)**

The paper acknowledges the sensitivities of DIAL surveys, and then acknowledges the failure of the study to properly account for these limitations. Because a controlled study conducted at a single refinery operating in the same manner (maximum capacity) in the same month of the same season (August) could not overcome the limitations of the method, it is impractical to conclude that this broad tool is a necessary component of an already comprehensive and stringent LDAR program. Optical sensing is unproven, has never been required as part of a BACT determination for a coal gasification facility, and data is not available to even document if it is effective at additional pollution mitigation. Therefore, it is not appropriate to include this technology as part of a BACT determination for the TEC.

Conclusions that fugitive VOC emissions can be underestimated based on the results of DIAL and SOF studies must be considered alongside other studies which disprove this conclusion. In June 2003, TCEQ commissioned a project team to develop emissions factors and correlation equations for fugitive ELC emissions based on the use of optical gas-imaging devices as a potential alternative or supplement to current organic vapor analyzer monitoring techniques required under TCEQ's LDAR programs. The primary recommendation from this study was stated as follows:

> **The data collected for components in HRVOC service are adequate to develop emission correlation equations specific to this service. The resulting correlation equations are very close to the SOCMI correlation equations that are already available for emission estimating. Both correlation lines fall within the**

confidence intervals of the other correlation. A statistical analysis of the HRVOC and SOCMI correlation equations indicates that they are not significantly different. . .

It is recommended that TCEQ continue to advise facilities to use the SOCMI correlation equations to estimate emissions from HRVOC streams. In the interest of furthering the science of emission estimation, it is also recommended TCEQ forward the HRVOC data to EPA for inclusion in some future update of the SOCMI correlation equations.[421]

This robust study concluded that gas-imaging techniques were no more effective at quantifying emissions from ELC than USEPA's Method 21, and therefore, this alternative ELC monitoring technique should not be pursued by TCEQ or USEPA. Indeed, the comment itself acknowledges that "the suite of existing options have not demonstrated the ability to provide the level of emission reductions as can be obtained from well-designed and implemented LDAR programs."

Because of the limitations of optical sensing as a stand-alone program, and the lack of evidence to indicated additional reductions would be realized with optical sensing in addition to LDAR, optical sensing is not appropriate for further consideration. As such, the permit appropriately identifies the LDAR monitoring requirements selected in the BACT analysis for ELC.

86. The cost-effectiveness analysis for the LDAR program was flawed. The Draft Permit would not require any source controls for any of these components, *i.e.*, leakless components. The application argues that leakless components are not cost-effective[422] and IEPA apparently accepts this conclusion without reviewing its underpinnings.[423] The BACT analysis for leaking components is flawed because it eliminated technically feasible controls, widely used in new facilities, based on a flawed cost analysis.

The cost-effectiveness analysis erroneously rejected the top controls based on a number of errors including the following:

(1) failed to demonstrate costs are unreasonable by comparison to costs borne by other similar sources;
(2) underestimated uncontrolled emissions by using the lowest published emission factors for a non-representative source, as already explained, rather than the maximum, as required for a potential to emit calculation;
(3) underestimated emission reductions for leakless components by assuming LDAR controls in place for highest emitters;
(4) evaluated wrong greenhouse gas pollutant;
(5) failed to include all controlled pollutants in calculating dollars per ton of pollutant removed;
(6) overestimated and unsupported capital cost; and

[421] **"Final Report: Development of Emissions Factors and/or Correlation Equations for Gas Leak Detection, and the Development of an EPA Protocol for the Use of a Gas-imaging Device as an Alternative or Supplement to Current Leak Detection and Evaluation Methods," prepared by ENVIRON for the TCET and TCEQ, dated October 29, 2004, pp. 6-14.**
[422] Ap., v. 1, Sec. 6.6.1.4, p. 6-47 ($733,035/ton).
[423] Project Summary, pp. *72-75.*

(7) excluded connectors.

Finally, the Draft Permit conditions do not assure that the assumptions that were used in the cost-effectiveness analyses are actually realized as it requires no demonstration at all of actual emissions or any of the assumptions that went into the emission calculations.

The thorough top-down BACT evaluation for ELC identified leakless components as the top technically feasible control technology for most equipment leak components (except where technically infeasible – such as PRVs). CCG appropriately analyzed other energy, environmental, and economic impacts of the top control technology under Step 4 of the BACT evaluation. This Step 4 analysis concluded that leakless components were not BACT for TEC due to high annualized control costs which were not considered to be cost effective.

CCG described in detail the site-specific cost evaluation conducted for leakless components in Section 6.6.1.4 of Volume 1 to the Application. CCG also explicitly referenced BACT determinations for similar sources, stating "The use of 'leakless' components has not been demonstrated to be cost effective at any other IGCC or SNG plant, even when evaluating the application of 'leakless' components while relying on very conservative assumptions." CCG also made conservative assumptions to "ensure that the cost summary presented in this analysis will be lower than actual costs that may be incurred."[424] As part of these conservative assumptions, CCG again referenced a similar source, Kentucky NewGas, to identify the difference in capital costs of leakless valves and pumps in gas and light liquid service compared to corresponding conventional components that do not qualify as "leakless." Kentucky NewGas was identified as a similar source for comparison because both facilities will produce SNG using bituminous coal as a feedstock and the types of equipment leak components (both leakless and conventional) will be of a similar design for the similar process streams present at the two facilities.

CCG completed the conservative estimate of the total annual costs for installing and operating leakless valves and pumps by estimating costs for freight, taxes, and installation costs. As is typically recommended by the USEPA's Office of Air *Quality Planning and Standards Control Cost Manual* (herein referred to as the "Control Cost Manual), costs for taxes, freight, and installation are determined based on a multiplier of the equipment cost. Section 2 Chapter 1 for Hoods, Ductwork, and Stacks and Section 3.2 Chapter 1 for Flares (which includes cost calculations for flare header piping, as discussed elsewhere both provide representative estimates for freight costs and sales taxes as a percentage of equipment costs (5% and 3%, respectively).[425] These same values were used by CCG in the leakless component cost evaluation, and thus, this aspect of the cost evaluation follows USEPA guidance on the topic of quantifying total annual costs for similar types of equipment.

---

[424] **Section 6.6.1.4 of Volume 1 of the Application, p. 6-45 and 6-46.**

[425] **USEPA Office of Air Quality Planning and Standards, *Air Pollution Control Cost Manual - Sixth Edition* (EPA 452/B-02-001), Section 2 Chapter 1 pg. 1-49 and Section 3.2 Chapter 1 pg. 1-32, available at http://www.epa.gov/ttn/catc/products.html**

Installation cost calculations in the Control Cost Manual include multiple cost components including both direct and indirect installation costs. Total direct installation costs typically include estimates for foundations and supports, handling and erection, electrical, piping, insulation, and painting. Total indirect installation costs include engineering, construction and field expenses, contractor fees, start-up, performance tests, and contingencies. For flare header piping that would include various types of ELC, USEPA recommends an installation cost multiplier of 1.92 times the equipment cost to account for all of the direct and indirect costs associated with installing a new flare header.[426] For the installation of hoods, ductwork, and stacks which would involve installing piping, fans, dampers, and other equipment similar to ELC on hard piping, USEPA recommends an installation cost multiplier of 1.25 to 2.00 times the equipment costs.[427] As shown in Section D-2 of Appendix D to Volume 1 of the Application, CCG used an installation cost multiplier of only 1.25 times the incremental equipment cost for installing leakless valves and pumps instead of installing conventional components, and therefore, CCG's estimate for installation cost is at the very low end of what USEPA would allow for similar equipment.

While it is true that non-leakless, conventional valves or pumps would also include freight costs, taxes, and installation costs, USEPA clearly considers these costs to be a function of total equipment cost. More expensive leakless components will thus cost more to install than conventional components. Because the capital costs referenced from Kentucky NewGas and used in the TEC leakless component cost evaluation are the *difference* in cost for more expensive leakless components, including the *difference* in freight, taxes, and installation is appropriate.

The Control Cost Manual also notes that indirect annual costs should be considered for control technologies considered as BACT, where annual property taxes, annual insurance costs, administrative charges, and operating, maintenance, supervisory, and overhead labor costs are all included and are calculated as a percentage of total capital costs. Although the difference in cost for leakless components would justify an estimated increase in indirect annual costs, CCG did not include these indirect annual costs in the economic analysis, in order to ensure a conservative and straightforward analysis. Maintaining more complex leakless valves and pumps would certainly cost more than maintaining conventional components, but CCG intentionally left these costs out of the leakless component cost evaluation to ensure the dollar per ton pollutant removed values were conservative.

CCG also described in the Application that a detailed cost evaluation was conducted only for leakless valves and pumps. The TEC Application acknowledged that leakless connectors are available (such as welded flanges in place of bolted fittings), but identified through comparison that because leakless valves and pumps were economically infeasible, leakless connectors would be even more costly per pollutant ton of pollutant removed. The cost ineffectiveness for leakless connectors would be

---

[426] **USEPA Office of Air Quality Planning and Standards, *Air Pollution Control Cost Manual - Sixth Edition* (EPA 452/B-02-001), Section 3.2 Chapter 1 pg. 1-32, available at http://www.epa.gov/ttn/catc/products.html**

[427] **USEPA Office of Air Quality Planning and Standards, *Air Pollution Control Cost Manual - Sixth Edition* (EPA 452/B-02-001), Section 2 Chapter 1 pg. 1-50, available at http://www.epa.gov/ttn/catc/products.html**

exacerbated as the emissions rate for connectors is significantly less than valves (70% less) and pumps (99% less). With a significantly smaller denominator (tons of pollutant abated) and a incremental annual cost increase per component that is expected to be similar to or smaller than that calculated for valves and pumps, the annual control cost for installing leakless connectors would only be higher and less cost effective than installing leakless valves and pumps. Further justification for this conclusion regarding costs for leakless connectors is provided in responses to other comments.

The cost evaluation for leakless valves and pumps in gas and light liquid service was conducted on a pollutant-specific basis. BACT is traditionally conducted on a pollutant-specific basis and the differing compositions of various process streams necessitates a refined approach to the cost calculations. It is not appropriate to base a cost effectiveness calculation on the facility-wide equipment leak component total as many of the process streams will not include all pollutants. For example, the lines in fuel gas service in the gasification block that supply SNG or natural gas to combustion equipment will have negligible concentrations of VOM and CO, and the component counts for the Gasification, Syngas Conditioning, and Methanation process area include more than 1,000 components in fuel gas service. Including the components in fuel gas service within the VOM cost effectiveness calculations for use of leakless components or a facility-wide LDAR program would artificially inflate the annual control cost without providing any measurable reduction in VOM or CO emissions. CCG performed a VOM cost effectiveness calculation only for components in VOM service. Similarly, the CO, CO_2, and methane cost effectiveness calculations were based only on components in CO, CO_2, and methane service, respectively. CCG ensured an appropriate and conservative cost estimate evaluation by considering only the components with potential emissions of the specific pollutant being evaluated, and assuming that the use of leakless components or a facility-wide LDAR program would reduce emissions only from the components in the particular service being evaluated.

CCG determined that the cost effectiveness of installing leakless components would be as follows:

- **$61,077 per ton of CO controlled (Table 6-3 of Volume 1 of the Application),**
- **$81,516 per ton of VOM controlled (Table 6-5 of Volume 1 of the Application),**
- **$13,754 per ton of CO_2 controlled (Table 6-4 of Volume 3 of the Application), and**
- **$65,420 per ton of methane controlled, which is $3,115 per ton on a CO_2e basis (Table 6-6 of Volume 3 of the Application).**

CCG determined that the cost effectiveness of conducting a facility-wide LDAR program would be as follows:

- **$5,403 per ton of CO controlled (Table 6-4 of Volume 1 of the Application),**
- **$115,417 per ton of VOM controlled (Table 6-6 of Volume 1 of the Application),**
- **$961 per ton of CO_2 controlled (Table 6-5 of Volume 3 of the Application), and**
- **$4,352 per ton of methane controlled, which is $207 per ton on a CO_2e basis (Table 6-7 of Volume 3 of the Application).**

The comment also suggests that the Draft Permit is somehow deficient because it does not require demonstration of the assumptions used in the cost effectiveness analysis, specifically that "it requires no demonstration at all of actual emissions or any of the assumptions that went into the emissions calculations." Detail on how this statement represents a misperception of the requirements of the Draft Permit is provided in response to a previous comment. Condition 4.9.5 of the Draft Permit requires CCG to demonstrate compliance with ELC emission limits using an appropriate USEPA methodology. This appropriate methodology could include any of the approaches defined in USEPA's *Protocol for Equipment Leak Emissions Estimates*, which include the Screening Ranges Approach and the Correlation Approach. Using one of these possible approaches would be expected to result in lower emissions estimates for equipment leak components than estimated in the Application and included as BACT limits in the Draft Permit.

87. The cost-effectiveness analyses also failed to show an adverse or excessive economic impact. The top technologies, leakless components and LDAR, were eliminated in Step 4 of the top-down BACT analysis for each PSD pollutant as not cost-effective. In each case, the cost-effectiveness in dollars per ton is estimated and rejected as not cost-effective with no explanation for why the estimated dollars per ton is not acceptable. Rejection language includes: "cost infeasible," (v. 1, p. 6-42), "clearly not economically feasible" (v. 1, p. 6-48), and "not economically feasible" (v. 1, p. 6-49). Rejection of a control alternative as not cost-effective requires comparison with the range of costs normally associated with BACT for similar facilities.[428] The Application does not contain any comparative cost data, even though leakless components and LDAR programs have been required for many similar processing facilities.[429]

The relevant question is whether the cost of the BACT control is disproportionate compared to other plants using the same control. The Application does not disclose the range considered to be cost-effective, but rather rejects all cost-effectiveness values, even those routinely considered cost-effective for other similar sources. If the cost of a technology in dollars per ton is on the same order as the cost previously borne by other sources of the same type in applying that control, the control should initially be considered economically achievable and therefore acceptable as BACT.[430] The Application did not present any cost-effectiveness data for other similar sources, but rather rejected estimated costs with no explanation.

Some of the cost-effectiveness values reported in the Application are clearly cost- effective before any of the corrections recommended in these comments are made. These include the cost of a facility-wide LDAR program estimated to cost $5,403 per ton of CO controlled[431] and $207/ton of methane(as CO_2-e) controlled.[432] Mississippi Lime, for example, reported

[428] NSR Manual, Sec. IV.D.2.c.
[429] *See*, for example, TransGas Permit (Commenter's Exhibit 72) Cond. 4.1.9, p. 32 (e.g., pumps in hydrocarbon service and valves are required to have sealless design; 915 of 1,045 total connectors are required to be welded together.).
[430] NSR Manual, p. B.44. *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, slip op. at ; *In re Masonite Corp., 5* E.A.D. 551, 554 (EAB 1994).
[431] Ap., v. 1, p. 6-49, Table 6-4.
[432] Ap., v. 3, p. 6-39, Table 6-7.

a cost-effectiveness range of up to $5,000 to $10,000 per ton for criteria pollutants and[433] SIE assumed a threshold of $10,000/ton in its cost analysis for a similar gasification project.[434] The Application itself concedes that $10,000/ton is a commonly accepted threshold for non-GHG pollutants,[435] but fails to apply it in its own cost analysis.

A control alternative that has been found to be cost-effective in other similar applications cannot be rejected as BACT unless unusual circumstances exist and are documented in the record. As explained in the NSR Manual, "... where unusual factors exist that result in cost/economic impacts beyond the range normally incurred by other sources in that category, the technology can be eliminated provided the applicant has adequately identified the circumstances, including the cost or other analyses, that show what is significantly different about the proposed source." The record contains no such documentation.

The comment refers to the application to identify where leakless components and LDAR for low VOM streams were addressed as economically infeasible. The comment suggests that a conclusion of economic infeasibility is relative, and cannot be ascertained simply from the cost per ton of pollutant removed, but only in the context of cost borne by similar facilities, basing this claim on the NSR Manual. However, the comment misrepresents the relevant USEPA guidance in the NSR Manual. Section IV.D.2.c. of the NSR Manual actually provides:

> **In essence, if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT. However, unusual circumstances may greatly affect the cost of controls in a specific application. If so they should be documented. An example of an unusual circumstance might be the unavailability in an arid region of the large amounts of water needed for a scrubbing system. Acquiring water from a distant location might add unreasonable costs to the alternative, thereby justifying its elimination on economic grounds. Consequently, where unusual factors exist that result in cost/economic impacts beyond the range normally incurred by other sources in that category, the technology can be eliminated provided the applicant has adequately identified the circumstances, including the cost or other analyses, that show what is significantly different about the proposed source.**
> **NSR Manual, page B.44.**

Considering the reference in its entirety expands upon the comment's restricted suggestion that the only relevant question is whether the cost of the BACT control is

---

[433] IEPA, Project Summary for an Application for Construction Permit/PSD Approval from Mississippi Lime Company for a Lime Manufacturing Plant in Prairie Du Rocher, Illinois, October 4, 2010; http://www.epa.state.il.us/public-notices/2010/mississippi-lime-pdr/project-summary.pdf. (Commenter's Exhibit 90)

[434] Southeast Idaho Energy, LLC, Addendum 1 to the Application for Authorization to Construct the Power County Advanced Energy Center, July 1, 2008, p. 9. (Commenter's Exhibit 91) See also: Memorandum from John S. Seitz, OAQPS, Re: BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Sulfur Refinery Projects, January 19, 2001 and San Joaquin Valley Air Pollution Control District, Final Staff Report, http://www.valleyair.org/busind/pto/bact/May%202008%20BACT%20cost%20effectiveness%20threshold%20update%20staff%20report.pdf. (Commenter's Exhibit 92)

[435] Ap v. 3, p. 6-34.

disproportionate compared to other plants using the same control. Instead, this is not the only relevant question – but just a component of the greater BACT evaluation. The above quote clearly states that certain circumstances could greatly affect the cost controls and therefore the BACT determination for a facility. In another section of the NSR Manual, USEPA states "The BACT determination must take into account all of the factors affecting the facility…The BACT analysis, therefore, involves judgment and balancing."[436]

It was concluded that leakless components were not cost effective following site-specific considerations, which did include a review of relevant similar source determinations. Section 6.6.1.4. of Volume 1 of the Application indicates that other BACT determinations for similar sources were considered, but "leakless" components have not been demonstrated to be cost effective at any other similar gasification facility. The comment claims that the cost values presented in the Application are "routinely considered cost-effective for other similar sources," yet they provide no relevant examples. No BACT determinations have been identified that calculate annual control costs in the range of that calculated for leakless components for any source in any location and that also consider these costs to be cost effective. The comment identifies the annual control cost for CO and CO_2e control through a facility-wide LDAR ($5,403 and $207 per ton pollutant removed, respectively) as cost effective. The comment presents this conclusion in disregard of their own argument – that the cost effectiveness of BACT should be compared to BACT determinations of other *similar sources*.

The source presented in the comment as a comparable source is Mississippi Lime, a calcium lime producer. Mississippi Lime's application and permit do not include a BACT evaluation of equipment leak components because no ELC that emit criteria pollutants are expected to be present at the site.[437] Mississippi Lime and TEC are not in any sense of the word "similar," and therefore, it is not correct to compare the conclusions of control cost calculations for these two very dissimilar sources. On page B.44, the NSR Manual clearly states that the cost effectiveness result should be compared only to "other sources of the same type."

The comment's reference to $5,000 to $10,000 per ton as a cost effectiveness range from Mississippi Lime is not relevant to the ELC cost analysis for CO and VOM emissions at the TEC. The citation is provided as footnote 10 to the last sentence in the following statements in Mississippi Lime's project summary (Commenter's Exhibit 90) regarding the SO_2 BACT evaluation for the lime kilns:

> **An appropriate SO_2 BACT emission limit with the scrubber is 0.645 lbs SO_2 per ton of lime produced, on a daily or 24-hour average basis. This represents a nominal control efficiency of over 97 percent based on the design fuel supply for the kilns, considering only the SO_2 emissions attributable to sulfur introduced with fuel and disregarding any sulfur retained in the lime product. [footnote 8]**

---

[436] **USEPA Responses to Public Comments on the Proposed PSD Permit for the Desert Rock Energy Facility, July 31, 2008, p.41-42, available at http://www.epa.gov/region9/air/permit/desert-rock/administrative.html.**

[437] **The PSD and Title V Greenhouse Gas Tailoring rule was not effective when the Mississippi Lime permit was issued, so the permit does not provide relevant information regarding potential GHG emissions from equipment leak components at Mississippi Lime.**

Given the level of SO_2 removal that would be required to be achieved by natural scrubbing, further add-on control equipment is not warranted for SO_2, both because of cost and because of the uncertainty of any significant further reduction in SO_2 emissions with such equipment. In addition, use of natural gas, which would be an essentially sulfur-free clean fuel for SO_2 emissions, is not warranted.[footnote 8] The associated cost for control of SO_2 emissions would clearly be excessive, as it would be in excess of $20,000 per ton of SO_2 controlled. [footnote 10][438]

The relevant portion of the Footnote 10 states the following:

Assuming that use of natural gas would reduce emissions of SO_2 to essentially zero, the accompanying reduction in SO_2 emissions would be 283 tons per year. This results in a cost-effectiveness from the use of natural gas that would be about $40,000 per ton of SO_2 controlled ($11,560,000/year ÷ 283 tons/year = $40,847/ton). The cost-effectiveness of use of diesel fuel as the principal fuel for the kilns would be over $200,000 per ton of SO_2 controlled, as the cost of diesel fuel per mmBtu is more than five times more than that of natural gas. The cost-effectiveness of the use of lower sulfur and more costly solid fuels is also excessive. The key factor in all these evaluations of the potential use of alternative fuels is that most of the SO_2 emissions theoretically present with solid fuel would be controlled by natural scrubbing and as they are already being controlled without any added cost, would not be affected by the use of an alternative fuel.

Consideration of the reduction in emissions of other regulated pollutants that might accompany use of natural gas would not meaningfully alter this conclusion. This is because it should not be expected that the particulate emissions of the kilns would change if fired on natural gas, given the level of control of required for particulate with most particulate attributable to limestone and lime dust. The only accompanying decrease in particulate emissions would be from elimination of fuel handling, involving emissions of at most a few tons per year.

This conclusion would not be altered if GHGs were a regulated NSR pollutant. This is because the upper bound on reasonable cost-effectiveness values for the control of GHGs is in the range of $10 to $20 per ton of GHG controlled, compared to $5,000 to $10,000 per ton. For example, if one assumes that the use of natural gas would eliminate emissions of 300,000 tons of GHG annually, with a reasonable cost effectiveness of $15 per ton, the value of this reduction would be $4,500,000 per year. The adjusted cost-effectiveness for the use of the alternative use of natural gas would then become $25,000 per ton of SO_2 controlled (($11,560,000 - $4,500,000) ÷283 tons = $24,947/ton, ≈ $25,000/ton).[439]

[438] **Commenter's Exhibit 90, p. 10.**
[439] **Commenter's Exhibit 90, see footnote 10, p. 10.**

The Project Summary for Mississippi Lime simply presents a range of cost effectiveness values for criteria pollutants as a rough comparison to cost effectiveness values that are expected to be commonly applied to GHG. Even if these cost effectiveness ranges applied directly as the comment suggests, the conclusions of the ELC BACT determination would be the same. The annual control costs of installing leakless components for reducing CO and VOM emissions (i.e., $61,077 per ton of CO controlled and $81,516 per ton of VOM controlled) are much greater than even the high end of the $5,000-$10,000 per ton cited by the comment. The annual control cost for installing leakless components to reduce GHG emissions far exceeds $10-$20 per ton regardless of whether or not CO_2 and CH_4 are evaluated individually or on a combined CO_2e basis. The annual control cost for conducting a LDAR program on low-VOM components to further reduce VOM emissions from the already low levels achieved by implementing an LDAR program on high-VOM components is $115,417 per ton of VOM controlled, which is more than 10 time higher than the high end of the cost effectiveness range referenced in the Mississippi Lime project summary. Although the annual control cost for implementing a facility-wide LDAR program to reduce CO emissions ($5,403 per ton of CO controlled) is within the cost effectiveness range referenced in the Mississippi Lime project summary, the cost effectiveness threshold for CO control options is often lower than for other criteria pollutant control options, such that CO annual control costs are not directly comparable to other criteria pollutants. As discussed in Section 7.2.4.1 of the Application, CO has far less health impacts at comparable ambient concentrations than other criteria pollutants, and thus USEPA and state air agencies do not require facilities to bear as high a cost for controlling CO emissions as they would for other criteria pollutants with greater health impacts at lower concentrations (i.e., NO_X and VOM). Even considering this factor, the annual control cost for conducting a facility-wide LDAR program to reduce CO emissions from ELC is above the low end of the cost effectiveness range cited in the Mississippi Lime project summary that is commonly applied to non-CO criteria pollutants. Finally, the annual control cost for conducting a facility-wide LDAR program to reduce GHG emissions from ELC is much greater than the $10-20 per ton range cited by the IEPA in the Mississippi Lime project summary regardless of whether costs are calculated for CO_2 and CH_4 separately or on a combined CO_2e basis.

The comment also points to a "bright-line" cost effectiveness threshold of $10,000/ton cited in the Southeast Idaho Energy, LLC (SIE) Application. This threshold was identified by the applicant as the benchmark for their case-specific BACT determination for a steam superheater and does not represent an agency policy or determination of a widely-applicable threshold.[440] A control cost analysis for a steam superheater BACT evaluation cannot be directly compared to a control cost analysis for a facility-wide LDAR program for equipment leak components at a coal gasification facility. Of relevance, the SIE Air Quality Permit does not require facility-wide LDAR for equipment leak components, only BMP for fugitive CO emissions from the gasifier process streams and the syngas cleanup streams.[441]

---

[440] **Commenter's Exhibit 91.**

[441] **Southeast Idaho Energy, LLC, Air Quality Permit to Construct Number: P-2008.0066, available at http://www.deq.idaho.gov/permitting/issued-permits.aspx/?page=83&records=10&type=all&sort=nameAscending In the footnote reference**

The comment also references BACT cost effectiveness thresholds for pollutant defined by the San Joaquin Valley Air Pollution Control District (SJVAPCD) as specified in a document entitled *Update to Rule 2201 Best Available Control Technology (BACT) Cost Effectiveness Thresholds*.[442] As the title of document indicates, this SJVAPCD staff report updated outdated cost effectiveness thresholds that had been established in 1991 based on a comprehensive review of more recent control cost determinations made by the other air pollution control districts in California and to address the current ozone non-attainment status of large portions of the state. As explained in this document, the previous cost effectiveness thresholds applied by SJVAPCD for CO and VOM were $300 and $5,000 per ton, respectively. Through the analysis discussed in the report, SJVAPCD staff recommended an increase in the VOM cost effectiveness threshold to $17,500/ton of pollutant removed and a change in the control calculation methodology to a new approach that is not aligned with the average cost effectiveness approach recommended by USEPA in the NSR Manual.[443]

A facility-wide LDAR program at the TEC for CO emissions was determined to have an annual control cost of $5,402 per ton of CO removed, and this cost would clearly be considered cost ineffective if the SJVAPCD thresholds were applicable. Similarly, the annual control costs from reducing VOM emissions through installing leakless components and implementing a LDAR program on low-VOM components are both considerably more than even the revised SJVAPCD cost effectiveness threshold. Even based on the information for control cost effectiveness cited in the commenter's exhibits, the costs for installing leakless components and conducting a facility-wide LDAR would not be cost effective for reducing emissions of CO, VOM or GHG.

A control alternative that has been found to be cost-effective in other similar source applications should not be rejected as BACT unless unusual circumstances exist and are documented. However, as documented in Section 6.6.1.4 of Volume 1 of the Application, "The use of 'leakless' components has not been demonstrated to be cost

---

for SIE, the comment also refers to a January 19, 2001 memorandum from John S. Seitz. This memorandum also quotes an upper bound cost effectiveness threshold of $10,000 per ton, but utilizes this upper range only for NO_X for new refinery process heaters. NO_X will not be emitted from the equipment leak components at the TEC. The memorandum does present an additional analysis comparing the cost effectiveness of refinery NSPS and the HON for reducing VOM emissions from refinery equipment leak components. For the reasons discussed previously, the equipment leak components at the TEC will not be similar to a refinery, as is evident by a simple comparison of the uncontrolled baseline VOM emissions from model refineries considered in USEPA's analysis (i.e., 71 to 133 tpy) to the uncontrolled VOM emissions from the TEC (i.e., 29.1 tpy, refer to Section 6.6 to Volume 1 of the Application, page 6-42)

[442] San Joaquin Valley Air Pollution Control District, Final Staff Report, http://www.valleyair.org/busind/pto/bact/May%202008%20BACT%20cost%20effectiveness%20threshold%20update%20staff%20report.pdf.

[443] "IV. Options For Revising The SJVAPCD BACT Policy:
Option #3: Increase the cost thresholds to the highest of the other surveyed Districts and change the methodology used in calculating the emission reduction to that used by most other Districts, i.e. calculate emission reductions as the difference between industry standard emissions (i.e. emissions required by SJVAPCD rules) and emissions with technologically feasible controls.
Option #3 is the recommended approach given the SJVAPCD's extreme non-attainment status. In addition, using SJVAPCD rule limits (or permitted emission limits) as the starting point for calculating emission reductions from installing technologically feasible controls is less subjective and is a better estimate of the actual emission reduction achievable due to installing technologically feasible controls.[443]
V. Proposed Cost Effectiveness Thresholds And Emission Reduction Calculation Methodology
The proposed cost effectiveness thresholds (option #3) to determine if a technologically feasible control technology is cost effective are as follow:

Pollutant	Cost effectiveness ($/ton)
NO_x	24,500
CO	300
VOC	17,500
SO_x	18,300
PM_{10}	11,400

effective at any other IGCC or SNG facility, even when evaluating the application of 'leakless' components while relying on very conservative assumptions." The comment references the TransGas Permit as evidence that LDAR programs and leakless components have been required for many similar processing facilities. First, the TransGas coal to gasoline facility only shares similarities with the TEC in some portions of the gasification block and not on a facility-wide basis. The different process streams required to first convert syngas into methanol and subsequently into gasoline are not similar to the process streams in the gasification block at the TEC (with the possible exception of components in methanol service within the AGR process area). TransGas equipment leak components in the SOCMI portion of the plant used to produce methanol and gasoline are subject to 40 CFR 60 Subpart VVa. In addition, the LDAR requirements of the TransGas permit that will only be applied to equipment in VOC service are not as stringent as those already defined for high-VOM streams at the TEC. TransGas has a 10,000 ppm leak detection threshold for LDAR while the TEC's leak definitions are 500 ppm and 2,000 ppm (Condition 4.9.6(h)).[444]

The comment also references the leakless pump, valve, and connector requirements in Condition 4.1.9.1 of the TransGas permit.[445] The comment has made several errors in how the leakless component requirements of the TransGas permit were referenced. First, only pumps in hydrocarbon service are required to be sealless and not all of the pumps at the facility. Second, only 915 of the 1,045 connectors in the MTG and MeOH synthesis process areas of the plant are required to be welded together, so the thousands of connectors in the gasification and syngas processing areas of the TransGas plant would not be required to be leakless. Instead, these gasification block connectors are subject to the monthly LDAR monitoring requirement in Condition 4.1.9.2 based on a leak detection threshold of 10,000 ppmv. Leakless connector design and a plant-wide LDAR program for connectors was only chosen by TransGas to avoid triggering PSD applicability and no BACT analysis was required for TransGas' equipment leak components (or any other VOM emissions sources).

88. The cost-effectiveness analysis evaluated the wrong regulated greenhouse gas pollutant. The TEC would emit several GHG pollutants, including CO_2, CH_4, and nitrous oxide ("N_2O"). The BACT analysis for component leaks separately evaluated each of these pollutants based on the weight of the compound. These analyses concluded there were no cost-effective controls. However, the regulated pollutant under PSD is GHG, expressed on a CO_2-equivalent basis, so as to take into account the global warming potential of each individual pollutant.[446]

The difference in these metrics is material. The equipment leak CO_2 emissions amount to 177.4 ton/yr and the CH_4 emissions to 51.3 ton/yr. However, the CO_2e emissions are 1,255 ton/yr.[447] These differences matter in the cost-effectiveness analysis used to reject all controls for component leaks. For example, the Application concluded that it would cost

[444] **Commenter's Exhibit 72, pp. 32 and 33.**
[445] **The TransGas facility is a minor source under the PSD program and has not accepted leakless design as part of a BACT determination. The inclusion of leakless components at this site was a voluntary decision to avoid triggering PSD applicability for VOM, and any "synthetic minor" permit requirements derived from this permitting strategy are not relevant to the TEC (which is subject to PSD review for VOM).**
[446] 40 CFR 51.166.
[447] Ap., v. 3, p. 3-4, Table 3-3.

$961 per ton of CO_2 removed to use an LDAR program, which is outside of the proffered range of $3 to $300/ton CO_2e. However, if CO_2e had been used in this cost calculation instead of CO_2, the cost-effectiveness would be $113/ton CO_2e,[448] which is well within the proffered acceptable cost-effectiveness range. Thus, when the correct regulated GHG pollutant is used to evaluate costs, a facility-wide LDAR program is cost-effective.

Conducting the cost analysis for the TEC on a CO_2e basis would not change the conclusions of the analysis. The cost analysis for the TEC was completed on an individual GHG pollutant basis for two main reasons. First, the process streams at the TEC rarely overlap in GHG service. The two GHG pollutants potentially emitted by equipment leak components at the facility have very little overlap in their usage through the facility. The streams containing a significant amount of CH_4 differ completely from the streams having a significant concentration of CO_2. Therefore, conducting a BACT control cost analysis based on a grouped GHG pollutants is not necessary as a practical matter for the proposed plant, as the process streams being evaluated for equipment leak controls such as LDAR would only be achieving reductions in CO_2 or methane, not both simultaneously. Basing a calculation on only the GHG group would inaccurately characterize actual control effectiveness. More importantly, it could subsequently become problematic, when defining what is considered GHG service.

In addition to the common sense approach in addressing individual GHG pollutants to correspond to the single pollutants emitted from a process stream's equipment leak components for the TEC, precedent has been established to use this approach through previously issued permits for other gasification facilities. For example, the South Dakota Department of Environment and Natural Resources (SD DENR) focused only on an individual GHG pollutant in defining BACT for equipment leak components at the Hyperion Energy Center in Union County, South Dakota. In the Statement of Basis for the Hyperion Energy Center, SD DENR narrowed GHG BACT only to the single pollutant methane, as an appropriate determination of GHG service: "As such, DENR is proposing that equipment in greenhouse gas service is a piece of equipment that contains a liquid (gas or liquid) that is at least 5 percent by weight of methane."[449]

The second reason the GHG BACT evaluation for ELC on an individual pollutant basis is appropriate is that in order to have a successful LDAR program the monitoring device must be specifically calibrated to the pollutant for which emissions reductions are required. For the TEC, a facility-wide LDAR program would require that the monitoring equipment be calibrated to detect either methane or CO_2 emissions. Therefore, a separate LDAR program would have to be implemented for each pollutant, which is consistent with how the cost analysis was estimated.

If the annual control cost of implementing a facility-wide LDAR cost to reduce GHG emissions was estimated on a CO_2e basis, the result would be $170 per ton of GHG

[448] Cost-effectiveness = ($142,405/yr)/(1,255 ton/yr) based on Ap., v. 3, p. 6-35, Table 6-5 and p. 3-4, Table 3-3.

[449] **South Dakota Department of Environment and Natural Resources, "Statement of Basis Construction Deadline Extension Request for the Prevention of Significant Deterioration Permit #28.0701-PSD Hyperion Energy Center Near Elk Point Union County, South Dakota," page 58, available at http://denr.sd.gov/hyperionaqrfe.aspx**

removed.[450] This is outside the range of GHG control cost effectiveness deemed cost effective by the IEPA ($10 -$20/ton), which the comment has suggested as an appropriate reference. [451] The comment incorrectly calculates GHG cost effectiveness as $113 per ton CO_2e, assuming that facility-wide LDAR achieves 100% reduction in emissions, which is incorrect. CCG correctly calculated the GHG emissions reductions of a facility-wide LDAR program as 66% on a CO_2e basis.[452]

88. Emission reductions were underestimated. Cost-effectiveness is the annual cost in dollars per year divided by the amount of each pollutant that is removed in tons per year. For a given annual cost, the higher the emission reductions, the lower the cost-effectiveness value, and the more cost-effective the control. When emissions are underestimated, as here, cost-effectiveness in dollars per ton is overestimated. This can result in rejecting an economic control alternative as not cost-effective. This situation has occurred here.

The comment accurately describes the relationship between cost-effectiveness, control costs, and the amount of emissions reduced. Certainly, an underestimation of emissions may results in an overestimation of cost-effectiveness, however. This has not occurred for the TEC, as is explained in the responses to specific comments.

89. Emissions from Components Controlled by LDAR were underestimated. The emissions reported in the Application in Table 3-2 and used to calculate emission reductions from installing leakless components[453] include LDAR on the highest emitters.[454] In other words, in evaluating the cost effectiveness of installing leakless components, the Application erroneously assumed that the emissions to be controlled had already been reduced by 85% to 97% by using LDAR. However, there is no need for LDAR when leakless components are used as there are no leaks. The cost effectiveness analysis should have used the uncontrolled emissions, without LDAR. This would have resulted in higher emission reductions and thus much lower cost effectiveness values.

When performing the cost analysis for leakless components, CCG used uncontrolled SOCMI without ethylene emission factors for all valves and pumps in gas and light liquid service on CO or VOM containing process streams (CO for the CO cost calculation, VOM for the VOM cost calculation). A conservative 100% control efficiency was applied for leakless components. The comment is incorrect in stating that the Application based the cost effectiveness of leakless components on emissions rates already taking into account reduction credits from the application of a LDAR program to high-VOM process streams. In Table D-2.4 of Volume 1 of the Application, CCG estimated a total VOM reduction of 12.1 tpy based on 100% control achieved by the installation of leakless valves and pumps in gas and light liquid service. VOM emissions of 12.1 tpy represent the total uncontrolled emissions from valves and

---

[450] Cost Effectiveness = $170/ton (($142,405/yr)/(835 tons/yr) = $170/ton), based on Ap. B-1

[451] Commenter's Exhibit 90. It is also outside of the range presented in Section 6.4.1.4 of Volume 3 to the Application ($3-150 per ton GHG removed) and quoted correctly elsewhere by this commenter. (The comment misquotes the Application and the CAAAC Climate Change Workgroup Phase I Report.)

[452] { 148.2 tpy CO_2 reduced by LDAR (Section B-1 of Appendix B to Volume 3) + [32.7 tpy CH_4 reduced by LDAR (Section B-1 of Appendix B to Volume 3) x 21 GWP for CH_4] } / { 186.3 tpy CO_2 uncontrolled (p. 6-28 of Volume 3) + [51.3 tpy CH_4 uncontrolled (pg. 6-28 of Volume 3) x 21 GWP for CH_4] = 66% GHG control credit for LDAR (expressed on a CO_2e basis)

[453] Ap., v. 1, Tables 6-3; v. 3, Tables 6-4

[454] Ap., v. 1, Tables C-24.2, C-25.2, C-26.2, C-27.2 and v. 3, Tables A-16.2, A-17.2.

pumps in gas and light liquid service. If CCG had already taken into account LDAR, as the comment suggests, the total VOM emissions would have to be less than 2.44 tpy, the BACT limit under Condition 4.9.5 of the permit (which includes VOM emissions from all ELC at the TEC and reflects the use of an LDAR program on high-VOM process streams).

90. As explained in a previous comment, the application significantly underestimated emissions from leaking components by using an anomalously low emission factor and overestimating the control efficiency. Thus, emission reductions achieved by leakless components and facility-wide LDAR were underestimated and cost-effectiveness overestimated.

The responses to previous comments thoroughly addresses the validity of the emission data for equipment leak component. The equipment leak components BACT emissions limit in Condition 4.9.5 is based on the BACT determination and valid emission estimates. Because the emissions calculation were appropriate, and emissions are limited as such in the permit, the cost effectiveness calculations are accurate.

91. The cost analysis did not consider all pollutants controlled. The application estimates the cost-effectiveness of BACT for equipment leaks on a pollutant-by-pollutant basis. It includes a separate cost analysis for CO, VOCs, CO_2, and CH_4.[455] When calculating the cost of a control option, such as leakless components, which reduce emissions of numerous pollutants at the same time, the cost of that control option must be divided between the overall reductions in all pollutant emissions.

USEPA guidance states that when a control option controls multiple pollutants the costs are to be apportioned to each pollutant before the dollars per ton is figured for cost-effectiveness.[456] Responding to a question by Georgia permitting authorities on how to account for a control device that reduces both VOC and CO, USEPA agreed with the Georgia agency's interpretation that the cost-effectiveness should be calculated by "dividing the annualized cost of the control device by the total of the CO and VOC emissions reduced by said device." *Id.* Thus, in this case, the cost of leakless components and LDAR, which simultaneously reduce all pollutants otherwise emitted, must be divided by the total reduction of all pollutants reduced, *i.e.*, the sum of CO, VOC, H_2S, CO_2, and CH_4. This change alone reduces the dollars per ton of controlling these emissions to within the acceptable range. The IEPA has explicitly recognized this in a number of permitting actions, including for Universal Cement.[457]

[455] Application, CO - Vol. 1, p. 6-48, Table 6-3; VOC - Vol. 1, p. 6-51, Table 6-5; CO_2 - Vol. 3, p. 6-34, Table 6-4; and CH_4 - Vol. 3, p. 6-38, Table 6-6.
[456] Letter from Brian L. Beals, Chief Preconstruction/HAP Section, USEPA Air and Radiation Technology Branch, to Edward Cutrer, Jr., Program Manager, Georgia Department of Natural Resources, March 24, 1997 (Responding to a question by Georgia permitting authorities of how to account for a control device that reduces both VOC and CO, EPA agreed with the Georgia agency's interpretation that the cost-effectiveness should be calculated by "dividing the annualized cost of the control device by the total of the CO and VOC emissions reduced by said device."), (Commenter's Exhibit 93).
[457] IEPA, Project Summary for a Construction Permit Application from Universal Cement, LLC, for a Portland Cement Manufacturing Plant in Chicago, Illinois, September 4, 2011, p. 21 (In discussing clean fuels: "Unlike the examination of an add-on control devices [sic], which commonly is focused on control of a specific pollutant or combined control for multiple pollutants..."); available at: http://www.oole.com/url?sat&rctj&g&esrcs&sourceweb&cd1&ved0CEEQFjAA&urlhttp%3A%2F%2 Fwww.epa.state.il.us%2Fpublic-notices%2F201 1 %2Funiversal-cement%2Fproject-summary.pdf&ei- F8CT8vCNpTaiQKA3oW6D&usAFQjCNGhbJHU8ZK n7Z89r05-spDNGoH. (Commenter's Exhibit 94)

The CO BACT analysis, for example, evaluated the cost-effectiveness of using leakless components on all valves in gas and light liquid service and all pumps in light liquid service, bundled together. This analysis considered only 3,228 components out of a total of 24,979 components, or only 13% of the total. All connectors and all components in heavy liquid service were excluded.[458] Thus, cost-effectiveness is an incomplete basis for rejecting leakless components as BACT for CO.

CCG's cost-effectiveness analysis for CO concluded that it would cost $733,035 per year to remove 12 ton/yr of CO, resulting in a cost-effectiveness value of $61,077/ton.[459] Thus, it found leakless technology was not economically feasible to control CO emissions from the subject components.[460] However, these same 3,228 leakless components also simultaneously control other pollutants, including VOM, H_2S, CO_2, and CH_4.

I revised the cost-effectiveness analysis for leakless components to additionally include only CO_2e, but otherwise using all of CCG's assumptions. The same components that emit 12 ton/yr of CO also emit 69 ton/yr of CO_2 and 12 ton/yr of CH_4.

The regulated PSD pollutant for greenhouse gases is greenhouse gas equivalents or GHGe, calculated as set out in 40 CFR 52.2 1(b)(49)(ii). The mass of each greenhouse gas is multiplied by the gas's associated global warming potential, which is reported in Table A-1 to Subpart A of 40 CFR Part 98. The global warming potential of CO_2 is 1 and of methane, 21. The GHGe emitted from these components is 69 + (12 x 21) or 321 ton/yr GHGe. Thus, the total amount of PSD pollutants eliminated by using leakless technology on these components is at least 333 ton/yr (small amounts of H_2S and VOM are excluded). The cost-effectiveness for these components, based on total pollutants removed, is $2,200/ton.[461] This is well within the range of costs routinely considered to be acceptable for purposes of BACT. The costs would be lower yet if a more realistic estimate of emissions were used and other errors in the cost analysis were corrected.

Similarly, the CO BACT analysis rejected LDAR as BACT based on cost-effectiveness alone. This analysis assumed that all equipment leak components in CO or VOM service - 19,284 components - would be subject to an LDAR program that removed 93% of the CO. This analysis estimated that it would cost $156,526 per year to implement this program and that it would remove 29 ton/yr of CO. The resulting cost-effectiveness, $5,403/ton, was judged not economically feasible.[462] This conclusion is incorrect, as this value is well within the range routinely considered cost-effective.

However, if this calculation had included all controlled pollutants, LDAR would have been found to be highly cost-effective. Emission estimates in the application indicate the following emissions from the subject components, all of which would be reduced by the same 93% assumed only for CO[463]: CO - 30.51 ton/yr, VOM - 2.44 ton/yr, H_2S - 1.41

[458] Ap., v. 1, p. 6-46 and p. D-8.
[459] Ap., v. 1, Table 6-3 and pp. D-9 to D-10.
[460] Ap., v. 1, p. 6-48 and Table 6-3.
[461] Cost-effectiveness of leakless technology on valves in gas and light liquid service and pumps in light liquid service, based on all pollutants removed: ($733,035/ton/333 ton/yr) = $2,201/ton
[462] Ap., v. 1, pp. 6-49 to *6-50,* Table 6-4 and pp. D-2 to D-4.
[463] Ap., v. 1, Table 3-2 (for CO, VOM, H_2S) and v. 3, Table 3-3 (for CO_2 and CH_4).

ton/yr, CO_2 - 177.4 ton/yr, CH_4 - 51.31 ton/yr (or 1,077.5 ton/yr CO_2e) and total GHG 1,289.3 ton/yr, as CO_2e.

I revised the cost-effectiveness analysis for LDAR for CO control to assume that 93% of each of these pollutants would be removed, but otherwise using all of CCG's assumptions. This reduces the cost-effectiveness of a plant-wide LDAR program from $5,403/ton to $131/ton.[464] If CH_4 is included in the calculation as the mass rate rather than GHGe, the cost-effectiveness is still only $640/ton. These costs are at the lower end of the cost-effectiveness range. Actual cost-effectiveness would be much lower as this revised estimate does not address the fact that the Application significantly underestimates emissions from equipment leaks and makes a number of other errors that overestimate costs and underestimate emissions.

The IEPA does acknowledge that certain pollution mitigation options have multi-pollutant reduction potential, specifically in regards to clean fuels. However, the IEPA identifies the evaluation as "more complex" and conducts a qualitative assessment of the multi-pollutant effect. The IEPA does not consider cost effectiveness based on the combined mass of emissions reduced for all pollutants controlled for a multi-pollutant control scheme.[465]

For equipment leak components at the TEC, each process stream and service type results in unique emissions profiles. No single control technology simultaneously mitigates significant quantities of VOM, CO, and GHGs, as these are emitted from different components for different streams. Grouping all components together and considering the sum total of all pollutants reduced is not appropriate for the case-specific considerations necessary for the TEC, and may result in a cost effectiveness calculation that is less conservative and has no relationship to the cost of reducing ELC emissions at TEC. The comment presents an example identifying that the cost analysis for leakless components only considered 3,228 components out of the total 24,979 components at the facility. Although the correct total count of components at the facility is 24,864, not all of these components are capable of being replaced by leakless alternatives. The 3,228 components evaluated for CO BACT represent the total of all valves and pumps in gas and light liquid service on process streams containing CO. If CCG had blindly included all valves and pumps, regardless of the process stream, additional costs would have been calculated, without any additional CO mitigation. It is for this specific reason that CCG separately addressed VOM. Analogous to the CO BACT evaluation, CCG considered only the 3,684 valves and pumps in gas and light liquid service for process streams containing VOM.[466] While there is some overlap for valves and pumps in VOM service that are also in CO service, the difference in component counts analyzed for the different pollutants make it evident that performing a single evaluation using a sum total of all pollutants is not appropriate.

[464] Revised cost-effectiveness for plant-wide LDAR program, based on all controlled pollutants with methane expressed as GHGe: ($156,526/0.93 x 1,289.26 ton/yr) = $130.55/ton. With methane expressed on a mass basis: ($156,526/0.93 x 263.07 ton/yr) = $639.78/ton.
[465] **Commenter's Exhibit 94.**
[466] **Table D-2.4 of Volume 1 of the Application.**

Because BACT is a case-by-case analysis, it is appropriate to evaluate the unique considerations of the TEC in order to make a proper BACT determination. While the single precedent referenced by the comment suggests the cost analysis should consider the total pollutant removed, the USEPA provided this response for that single case-specific BACT determination, which would not share the same emissions characteristics associated with equipment leak components at a gasification facility. A total pollutant cost assessment is not appropriate in the case-specific BACT determination for the TEC.

In addition to the justification presented previously, BACT is completed on a pollutant by pollutant basis because pollutants do not all have the same value or equal weighting. It is not appropriate to combine GHG and other regulated pollutants in a cost analysis to compare to an arbitrarily chosen cost effectiveness threshold. Certain GHGs are emitted at much higher levels than other regulated pollutants and thus adding those into an emissions total for the reduction achieved by a particular multi-pollutant control option (either on a mass basis or a CO_2e basis) would create an unweighted emissions total for the cost effectiveness calculation. The inappropriateness of summing GHGs and other regulated pollutants is evident not just in the different cost threshold ranges discussed in responses to other comments, but also in the PSD major source thresholds. Regulating GHGs under the existing New Source Review thresholds created "absurd results," which drove USEPA to develop the Tailoring Rule that set an initial major source threshold for GHGs of 100,000 tpy, as CO_2e, as compared to the 100 or 250 tpy major source thresholds that otherwise apply.[467] If a separate threshold is necessary for determining PSD applicability, it would follow that a separate cost value is also necessary for BACT cost effectiveness for GHG, less one get the "absurd results" presented by the comment. CCG identified guidance from the CAAAC in Section 6.4.1.4. of Volume 3 of the application noting that GHG cost effectiveness determinations range between $3 and $150/ton. The IEPA and the comment references suggest that the upper bound of GHG cost effectiveness determinations should be no higher than $20/ton.[468]

The consideration of different cost effectiveness thresholds is not unique to GHGs. Based on the comment's referenced BACT guidance from San Joaquin Valley Unified Air Pollution Control District (SJVAPCD), the cost effectiveness thresholds for different criteria pollutants can vary by almost two orders of magnitude, depending on the case-specific evaluation. For example, the SJVAPCD identifies that a control technology for CO is not cost effective unless its costs fall below $300/ton. A control technology for VOC is not cost effective unless its costs fall below $5,000/ton.[469] Directly summing CO and VOC (or VOM for the TEC), as suggested by the comment to compare to either cost threshold would not be appropriate.

The comment re-calculates a total pollutant reduction cost effectiveness on a CO_2e basis for both leakless components and LDAR as $2,200/ton and $131/ton, respectively.

---

[467] **75 FR 31533.**
[468] **Commenter's Comment Exhibit 90, see footnote 10.**
[469] **Commenter's Comment Exhibit 92. p. 3. The older cost effectiveness threshold from SJVAPCD is referenced since it is calculated on the same basis as the control cost calculations for the TEC.**

The comment's approach to re-calculating the cost effectiveness is overly-simplified, and thus is inaccurate. As shown in the facility wide fugitive equipment leak component potential emission calculations presented in Sections C-24 to C-27 of Appendix C to Volume 1 of the Application, a facility-wide LDAR program does not achieve 93% reduction of all pollutants. CO_2 and methane are reduced only 79.5% and 63.8%, respectively. The combined total cost effectiveness is actually significantly higher than the values presented by the comment. Ignoring the flaws in the Comment's calculations, these cost effectiveness calculations are meaningless without a basis of comparison. Because no other similar source or agency has identified a combined pollutant cost effectiveness threshold for the unique distribution of CO, VOM, and GHG emissions from ELC at a coal gasification plant, no cost effectiveness threshold is available for comparison to the $131 per ton CO, VOM, and GHG removed annual control cost incorrectly calculated by the comment.

92. The estimates for capital costs were unsupported and overestimated. The starting point of the cost-effectiveness analyses for leakless components, the additional capital cost per component, is taken directly from the Kentucky NewGas Application, prepared by the same consultant, Trinity Consultants.[470] In fact, the text of the cost analyses in these two applications are nearly identical, indicating cutting-and-pasting. Neither application provides any basis for the claimed additional capital cost for the various control options.

The difference in capital cost of leakless components and non-leakless components utilized in the BACT cost evaluation was referenced from the Kentucky NewGas Application and was described in Section 6.6.1.4. of Volume 1 to the Application. CCG supported this reference in the Application by documenting the similarities between the equipment leak components of the Kentucky NewGas facility and the TEC. This control cost reference and documentation justifying the facilities as similar sources are consistent with the suggestion in a previous comment that TEC is required to consider and compare the costs of BACT control at similar sources, in accordance with the *NSR Manual.* The comment now suggests that considering the costs of BACT control at other similar sources is inappropriate.

Even if site-specific vendor quotes were available for the TEC, it is unlikely that the quotes would have an appreciable difference compared to the similar Kentucky NewGas facility. As explained in the NSR Manual, page B.44, that control cost options that are within ± 20 to 30 percent of each other should generally be considered to be indistinguishable when comparing options. With cost effectiveness calculations that are clearly economically infeasible, even a 20 to 30% change would not impact the conclusions relied upon for the TEC Draft Permit The small difference that TEC-specific vendor quotes may yield would not have changed the conclusion that the installation of leakless components at the TEC is not cost effective.

93. The estimates for Installation Costs were unsupported and overestimated. The cost analyses for leakless components assume that the cost to install leakless valves and pumps is 25% of the capital cost of the components.[471] No basis is provided. This is a common assumption

[470] Ap., v. 1, Appx. D, Tables D-2.3, D-2.4 and v. 3, p. 6-32.
[471] Ap., v. 1, pp. D-9 (CO), D-12 (VOM), Table D-2 and v. 2, p. B-2 (GHG).

for complex add-on pollution control equipment, such as an SCR, that involves site preparation, foundation, erection, painting, etc. However, for leakless valves and pumps, the only relevant installation costs are those that would be incurred in addition to installing a normal valve or pump in the same location. There is no additional installation cost for a leakless component as the seal and other modifications that render the component leakless are internal to the component. The installation costs should be the same. Thus, in my revised cost estimates below, I have set installation costs to zero.

The comment asserts that there is no basis for the installation costs calculated for leakless valves and pumps at the TEC. CCG specifically referenced as footnote 2 to each leakless component cost evaluation table (pages D-9 and D-12 of Volume 1 and page B-2 of Volume 3) the basis for the estimated installation costs as the average installation cost referenced from the Control Cost Manual, or 25% of the capital cost.

As previously discussed, the Control Cost Manual identifies direct installation costs including foundations and supports, handling and erection, electrical, piping, insulation, and painting. Indirect installation costs such as engineering, construction and field expenses, contractor fees, start-up, performance test, and contingencies can also be included in the total capital investment for a control technology. The combined total direct and indirect installation costs can comprise a significant fraction of the purchased equipment cost for similar equipment to ELC at the TEC.[472] Because equipment leak components themselves do not require significant supporting installation services, an average value of 25% for both direct and indirect installation was conservatively selected to capture appropriate charges for cost components such as foundations and supports, handling and erection, engineering, field expenses, contractor fees, and contingencies.

Vendors and contractors will typically bid installation costs as a percent of the purchased equipment costs. This practice is acknowledged through the cost factors presented in the Control Cost Manual. This is a reasonable practice for vendors and contractors to ensure appropriate compensation when installing more expensive equipment. CCG performed the BACT cost analysis for leakless components based on the cost *difference* between leakless components and non-leakless components. It is appropriate to apply to this purchased equipment cost difference a factor for installation costs, which will then account for the difference in installation costs.

The comment acknowledges the difference in purchased equipment costs but ignores a difference in installation costs. Because vendors will bid installation as a function of the total equipment cost, the comment's exclusion of this cost inappropriately underestimates the total capital investment of leakless components.

A comparison of the results of CCG's leakless component control cost evaluations presented in the Application to the results of the calculation if installation costs for leakless valves and pumps were excluded as the comment suggests would be appropriate shows that leakless components still would not be cost effective.

---

[472] **USEPA. Office of Air Quality Planning and Standards. OAQPS Control Cost Manual, Sixth Edition, Research Triangle Park. EPA 453/B-96-001.**

94. The cost analysis for leakless components excluded connectors. The application does not provide any cost estimate to eliminate leaks from the approximately 19,000 connectors projected for the TEC. These leaks could be completely eliminated at a net savings by welding connections instead of using bolted or other flanged connections. This would reduce emissions and the cost per ton by significant amounts. Instead, the Application simply dismisses leakless connectors, without even discussing them, erroneously arguing emission factors for connectors are 70% less than for valves and pumps, which were costed[473] and implausibly claiming they are not available.[474] This argument is wrong and results in rejecting welded connections, the top control that is widely used in new facilities, as not cost-effective without any analysis at all.

In fact, connectors make up the majority of the fugitive components, 18,798 or 75% of the total, and are responsible for 42% of the emissions. Thus, they should not be dismissed as not cost-effective based on the relative magnitude of emission factors and the purported cost of valves and pumps, without any analysis. Welded connections are less costly than flanged connections and if the emissions from these had been included in the cost analyses, the increase in cost would have been zero or negative and leakless technology for all components would have been cost-effective and thus required for all components.

Pipes, valves, pumps and other equipment are commonly connected using flanges that are welded or screwed. Flanged joints are made by bolting together two flanges with a gasket between them to provide a seal. The most commonly used flange types in the petroleum and chemical industry are welding neck flanges, slip on flanges, socket weld flanges, lap joint flanges, threaded flanges and blind flanges.

These joining methods leak, no matter how carefully executed. Further, flanged pipe system need much more space, *e.g.*, pipe racks. Insulation of flanged pipe systems is more expensive due to the need for special flange caps. There are no standards that define whether or not flange connections may be used. In a newly built facility, it is customary to minimize flanged connections, because only one weld is needed to connect two pieces of pipe. This saves on the capital costs of two flanges, the gasket, the stud bolts, the second weld, the cost of nondestructive tests for the second weld, etc. Welded connections, which eliminate 100% of the emissions, generally cost less than other joining methods that do have emissions.[475] However, here, the Application has assumed the old, non-BACT flange joining method, which does not satisfy BACT, I presume because including their emissions would render all leakless components cost-effective.

In sum, the use of leakless connectors does not increase cost, but significantly increase emission reduction. Thus, the inclusion of these components would improve the cost-effectiveness of leakless components. This will be considered in the following revised cost analysis.

[473] Ap., v. 1, pp. 6-46, D-8 and v. 3, p. 6-33.
[474] Ap., v. 1, p. D-8, note 2.
[475] Definitions and Details of Flanges; http://www.wennac.org/flanes/flanges general part1.html, Fundamentals of Professional Welding; http://www.waybuilder.net/free-ed/BldgConst/Welding01/welding01 v2.asp. (Commenter's Exhibit 95)

The comment asserts that the application does not include cost estimates for leakless connectors, but eliminate them from further consideration under Step 4 of BACT "without even discussing them." Section 6.6.1.4. in Volume 1 of the Application does "discuss" leakless connectors and provides a comparative cost assessment to the quantified values for valves and pumps. Regardless of the cost effectiveness of installing welded connectors, CCG may use welded connections to replace the flanged connections assumed in the application, where appropriate based on safety and engineering considerations which may make welded connections the best choice for a particular installation.

The comment claims that through the Application CCG was "erroneously arguing emissions factors for connectors are 70% less than for valves and pumps." The SOCMI without ethylene emission factor for valves in gas service is 0.0089 lb/hr/component, and for connectors in gas service is 0.0029 lb/hr/component. The SOCMI without ethylene for valves in light liquid service is 0.0025 lb/hr/component, and for light liquid connectors is 0.0005 lb/hr/component. The resulting ratio of connector to valve emissions factor for gas/vapor service 0.33 and for light liquid service is 0.14. Therefore, it is accurate to state that emissions from connectors are at least 70% less than emissions from valves. The disparity in emissions between connectors and pumps is even greater. The SOCMI without ethylene emission factor for pumps in light liquid service is 0.0386 lb/hr/component, and for connectors in light liquid service is 0.0005 lb/hr/component, or approximately 99% less.

The annual control cost calculated for installing leakless valves and pumps to reduce emissions from components in CO, VOM, and GHG service ($766,736 for CO components, $1,029,603 for VOM components, and $1,093,660 for GHG components) can be divided by the total number of valves and pumps evaluated (3,228 for CO components, 3,684 for VOM components, and 4,151 for GHG components) to determine annual control cost on a per component basis ($238/component for CO components, $279 for VOM components, and $263 for GHG components) for comparison against the per component costs that are expected for leakless connectors.

The per component cost of installing leakless connectors that would be deemed cost ineffective can be determined using worst-case and overly conservative cost effectiveness thresholds ($1,000/ton for CO, $10,000 per ton for VOM, and $20/ton for GHG) for comparison to the per component costs calculated for leakless valves and pumps. To arrive at this per component cost for leakless connectors, one can multiply the uncontrolled emission rates for connectors by the cost effectiveness threshold to calculate the annual control cost for installing leakless connectors and can then divide by the number of components in each pollutant specific service type to calculate per component cost. At a cost effectiveness threshold of $1,000 per ton for CO, the most CCG could be expected to pay to install and operate leakless connectors to reduce CO emissions would be $13,200 per year (i.e., $1,000/ton CO removed x 13.2 tpy CO removed = $13,200/yr). At a cost effectiveness threshold of $10,000 per ton for VOM, the most CCG could be expected to pay to install and operate leakless connectors to reduce VOM emissions would be $111,000 per year (i.e., $10,000/ton VOM removed x 11.1 tpy VOM removed = $111,000/yr). At a cost effectiveness threshold of $20 per ton

for CO_2e, the most CCG could be expected to pay to install and operate leakless connectors to reduce GHG emissions would be $9,250 per year (i.e., $20/ton CO_2e removed x 462.5 tpy CO_2e removed = $9,250/yr). With a total number of gas/vapor and light liquid connectors in CO service of 12,091, the annual control cost for CO translates to $5.45 per component. With a total number of gas/vapor and light liquid connectors in VOM service of 13,172, the annual control costs for VOM translates to $8.42 per component. Finally, based on 14,448 gas/vapor and light liquid connectors in GHG service, the annual control cost for GHG translates to $0.64 per component. These calculations demonstrate that the lower emissions from connectors on an uncontrolled basis result in much lower per component cost that can be deemed cost ineffective. As discussed further below, CCG fully expects that installing and maintaining tens of thousands of welded connectors at the TEC would cost much more than $111,000 per year (i.e., the maximum annual control cost that could be considered cost effective).

The comment asserts that leakless connectors are actually less costly than a regular flanged connection. In support of this claim, the comment provides a summary of a referenced webpage, from which the comment has seemingly assimilated their entire knowledge base regarding flanges and welded connectors. The accuracy and thoroughness of this comment's only reference is questionable. The reference is a personal website which includes the disclaimer "I can not be held responsibility for any incorrect information on a page from this website [sic]."[476] This is hardly a reliable technical reference to literature when the website contains a disclaimer and the disclaimer is not even grammatically correct.

The comment's assertion that requiring all connections to be welded as a BACT requirement is "less costly" than flanged connections is wrong. The comment, referencing the questionable website, claims that all welded connections would generally cost less than other joining methods because a single weld to connect two pipes saves on the capital costs of two flanges, the gasket, the stud bolts, the second weld, and the cost of non-destructive tests for the second weld. The comment inaccurately assumes all piping components would be custom built on-site.

The comment ignores the additional labor that would be required to weld almost 19,000 connections in the field, and then subsequently blast, paint, and test/inspect those connections. All of this custom, in the field labor is a cost that is above and beyond the cost of a pre-fabricated pipe section, with the flange pre-assembled, pre-painted, and already certified by inspection prior to arriving at the site. The TEC will be engineered to take advantage of pre-fabricated piping and components and purchase standardized equipment to create an economy of scale for significant cost savings. The comment's reliance on a single personal website leads to the inaccurate assumptions and incorrect conclusion that welded connectors are "less costly".

Welded connectors can also introduce operational challenges and difficulties, prohibiting expeditious repairs. A flange is a bolted, gasket-sealed junction used

---

[476] **Commenter's Exhibit 95, http://www.wermac.org/sitemap/about.html.**

wherever pipes or other equipment such as vessels, pumps, valves, and heat exchangers may require isolation or removal. Connectors are all other nonwelded fittings that serve a similar purpose to flanges, which also allow bends in pipes (elbows), joining two pipes (couplings), or joining three or four pipes (tees or crosses).[477] Utilizing welded connectors could delay maintenance and repairs, as physical cutting and re-welding would be required for all connector openings and closings. Due to delays in repair and longer out-of-service time during repairs, welded connectors could lead to longer durations of bypassed equipment being routed to the flare, and thus additional releases of emissions. This potential adverse environmental impact would further justify eliminating leakless connectors as the BACT level control option.

Collectively all of these added costs would comprise much more than a $111,000 per year and would make welded connectors cost ineffective. The added maintenance labor costs alone of having to inspect welded connections to identify any signs of failure would comprise the majority of this amount, as CCG would likely have to hire at least one full-time employee to oversee the safe operation of the welded connectors at the site. Additional costs for downtime in any operating year when weld failures are identified would only add to the cost, as would the increased labor costs required for repairing pipes with failed wells.

In its Permit-to-Install application, Ohio River Clean Fuels, LLC identified welded and soldered flanges as technically infeasible on the basis that they would present the operational complications identified above and they were dismissed from further evaluation in the BACT analysis.[478] This is consistent with the final BACT determination for equipment leak components for all gasification plants as identified in Section 6.6.1.4. of Volume 1 of the TEC Application. Leakless connectors are not technically feasible in many cases and certainly are not cost effective. The comment claims the opposite, that welded connections are "the top control that is widely used in new facilities." However, the comment provides only a single example where welded connectors are used – the TransGas coal-to-gasoline facility. The IEPA previously responded on the inappropriateness of comparing TransGas to the TEC. Based on a review of all recently issued similar source permits, welded connectors are in fact not required as BACT for any similar gasification plant.

95. The top control technology for equipment leaks is leakless components, which control 100% of emissions. These are widely used and have been required at existing refineries in Consent Decrees and at new facilities as BACT.[479] My cost analysis for leakless components corrects the errors in CCG's analysis discussed above. My revised analysis is based on the following: (1) all leaking components will be replaced by leakless equivalents; (2) the increase in capital cost for a leakless connector is zero; (3) installation costs for leakless and non-leakless components are identical; (4) no sales tax on pollution control

---

[477] USEPA, Inspection Manual: Federal Equipment Leak Regulations for the Chemical Manufacturing Industry, Volume I: Inspection Manual, December 1998, EPA/305/B-98/011.

[478] Ohio River Clean Fuels, LLC, Permit-to-Install Application: Ohio River Clean Fuels Facility, Village of Wellsville, Columbiana and Jefferson Counties, Ohio, page 6-23, available at http://www.epa.ohio.gov/portals/27/transfer/ptiApplication/orcf/Module6.pdf

[479] See, e.g., West Virginia Department of Environmental Protection, Division of Air Quality, Permit to Construct, TransGas Development Systems, LLC (Commenter's Exhibit 72), Cond. 4.1.9, p. 32 *(e.g.*, pumps in hydrocarbon service and valves are required to have sealless design; 915 of 1,045 total connectors are required to be welded together.)

equipment; (5) emission reductions for all controlled pollutants based on the EPA refinery emission factors; and (6) emission reductions based on the sum of all PSD pollutants, i.e., VOM, CO, H_2S and GHG (CO_2, and CH_4).

My analysis indicates that leakless components are highly cost-effective. The overall cost effectiveness of using leakless components on all valves, pumps, compressors and connectors is $1,725/ton on a mass basis and $474/ton on a GHGe basis.[480] These values are well within the range of acceptable costs. Further, when the various components are evaluated by type and service, the cost effectiveness is acceptable for all except valves in heavy liquid service ($24,929/ton). All other cost effectiveness values are less than $10,000/ton. Thus, leakless components should be required as BACT at least for all components except valves in heavy liquid service.

The TransGas permit requirements for leakless valves, pumps, and connectors do not indicate that leakless components are widely used at new facilities as BACT. TransGas took limits to be a minor source, so the leakless component requirements in the permit are not BACT. TransGas also produces Fischer-Tropsch fuels, and thus, large portions of the facility would have components that contact pure VOC. With a large number of components in pure VOC service, TransGas chose to implement leakless components in certain areas of the plant to limit VOC emissions to below the PSD major source threshold . One facility's choice to use leakless design on pumps, valves, and connectors in VOC service within certain process areas of a coal-to-liquids plant does not indicate leakless design is BACT for the TEC, which has far fewer components in VOC service.[481]

The comment prepared a revised cost analysis based on each of the claimed errors and also altered the emissions estimates from the uncontrolled equipment leak components consistent with the comment that USEPA's refinery factors are more representative of the TEC. These comments have been responded to elsewhere and shown to be incorrect. The comment's revised calculations are therefore based on incorrect changes to the cost evaluation and do not support a different BACT determination. Leakless components are not necessarily air pollution control equipment subject to the sales tax exemption in Illinois. Regardless, excluding sales tax on leakless components would not change the conclusion that leakless components are not cost effective for the TEC. The cost analysis performed by CCG for leakless components appropriately concluded that leakless components are not cost effective as BACT.

BACT WAS NOT REQUIRED FOR CERTAIN MATERIAL HANDLING OPERATIONS

96. The TEC will include active and inactive coal storage piles. Particulate matter will be emitted from these piles due to wind erosion; loading/unloading; and maintenance operations. The BACT analysis is flawed for each of these fugitive sources, i.e., wind erosion from the inactive storage pile (PIL1), coal transfer points associated with the open

[480] The results of the revised calculation were summarized in Table 15 of these and the detailed calculations were are included in Commenters' Exhibit 19, Tab Cost (2).

[481] **The comment does not cite any specific existing refinery consent decrees. CCG has indicated it is not aware of any existing refinery consent decrees requiring leakless components.**

inactive storage pile (TP1-3), and maintenance of the inactive storage pile (PIL1-3). The application concluded that BACT for the smaller pile is enclosure in a dome controlled by a baghouse. However, the application concluded with no support that it is not feasible to enclose the inactive coal pile due to its large size, about 8 acres with a footprint of 600 feet x 600 feet and a height of 45 feet or about 600,000 cubic yards assuming a cube.[482] Instead, the application concluded that BACT at the inactive pile is wet dust suppression and pile compaction.[483] This is not BACT for the inactive storage pile. As discussed below, the BACT analysis is incomplete and thus reached an erroneous conclusion.

The BACT analyses failed to consider all control options, evaluating only three control options: (1) enclosures; (2) dust suppression; and (3) compaction.[484] There are other demonstrated control options for storage piles that are widely used but were not considered in the Application. These include: pile geometry and orientation to minimize wind erosion emissions, a wind fence system, location of the pile within the facility to minimize emissions and offsite impacts[485]; or modifying the geometry of the pile as required to facilitate enclosure. Many of these are required under some state regulations.[486] Further, combinations of these measures were not evaluated. Combinations of measures achieve a higher control efficiency than one alone.

CCG completed a full BACT analysis considering all reasonably available alternatives for controlling fugitive PM emissions from the inactive piles. See Application at 8-15 through 8-18. The comment proposes a number of additional "control" alternatives but fails to demonstrate how incorporating any of these alternatives would actually lead to a lower fugitive emissions rate from the proposed storage piles.

The comment suggests that the BACT analysis should have included pile geometry and orientation and location of the pile within the facility as two additional control alternatives. As for the design of the pile, the Application provides dimensions based on the amount of material to be stored. See Application at C-46. The methodology utilized to calculate PM emissions from inactive pile wind erosion is based on the active surface area, silt content of the material stored, and percent of time the wind speed is greater than 12 mile per hour. Pile orientation and pile location do not impact the emission rate calculations for the pile. The geometry (the comment appears to be referring to pile size) impacts emissions only as it would relate to surface area. In the case of a storage pile, for a given quantity of material, one large pile has a smaller exposed surface area than two piles each storing half of the quantity. Thus, it is not an emission control technique in itself to create multiple storage piles from a single storage pile. The Permit requires that emissions from this source be minimized to the extent feasible. Permit at 63-64 (Condition 4.3.3-1.e.). Going beyond this to require

[482] Ap., v. 1, Appx. C, Table C-12.3, p. C-46, note 1.
[483] Ap., v. 1, pp. 8-11 and 8-17.
[484] Ap.,v. l,p. 8-16.
[485] *See* discussion of dust emissions from a March 2006 web discussion; available at http://www.bulkonline.com/Forum/showthread.php?t7184, (Commenter's Exhibit 97); California Association of Air Pollution Control Officers, Guidance on Storage Pile Fugitive Dust; available at http://www.caycoa.org/index.yhy?oytioncom content&viewarticle&id24%3Adust-storage-piles&catidl 7%3Aa-clearinhouse-subcateories&Itemid20, (Commenter's Exhibit 98)
[486] Air districts with aggressive fugitive dust control rules, which should be considered in BACT analyses: Districts within California: www.arb.ca.gov/drdb/drdb.htm; Clark County, NV: www.co.clark.nv.us/air quality/regs.htm; and Maricopa County, AZ. *See* also SCAQMD Rule 1158.

CCG to maintain a specific pile shape or orientation as BACT would be impractical and, in any event, is not necessary to limit emissions from this source to BACT levels. And, even if moving the pile towards the center of the facility would lessen offsite impacts directly attributable to the pile, it may at the same time increase haul road emissions as the vehicles transporting the piles materials on site would be forced to travel greater distances.

As for wind fences, this form of control was specifically included in the BACT analysis for the inactive storage piles as a subset of enclosures. See Application at 8-16 ("Enclosures can include structures such as domes or buildings that completely enclose a pile or three sided wind barriers that partially enclose a pile."). In addition, pursuant to 40 CFR 60.254(c)(2), USEPA identifies all of the following control options as equally effective for minimizing PM emissions from open coal storage piles as part of a fugitive coal dust emissions control plan under the Subpart Y NSPS: locating the source inside a partial enclosure, installing and operating a water spray or fogging system, applying appropriate chemical dust suppression agents on the source, use of a wind barrier, compaction, or use of a vegetative cover. Therefore, wind fences would provide no additional control effectiveness beyond that achieved by applying chemical suppressants to the active portion of the inactive pile.

97. Storage domes are feasible for the inactive pile. The BACT analysis eliminated storage domes for the inactive pile, arguing it was too big to enclose, but providing no specific details. However, the BACT analysis did not disclose the shape of the piles, the design of any considered enclosure, and did not consider changing the geometry of the piles and domes to eliminate any perceived size constraints. The pile dimensions were reported as 600 ft by 600 ft by 45 ft high. The websites of dome vendors advertise enclosures up to 1000 feet in diameter.[487] Further, two equal-sized piles could be used instead of one large pile. Further, the inactive pile is sized to hold a 60 day supply of coal or about 310,000 tons. This is excessive. Storage piles are typically designed for a 30 day inventory.

Regardless, enclosure of material storage piles is common. In California, the South Coast Air Quality Management District's ("SCAQMD") Rule 1158[488] requires all new and most existing coal, coke, and sulfur piles to be covered. There is no size exclusion. The SCAQMD implemented this rule in 1999 in response to the failure of its previous fugitive dust rule to adequately control emissions.[489] The BACT analysis did not provide any site-specific reason or point to any unusual circumstances as to why enclosures can be used elsewhere, but not here.

The previous SCAQMD rule only required closed storage for coke piles and allowed an exemption if a facility developed a management plan to control fugitive emissions, as here. The SCAQMD found that "ambient monitoring studies, on-going complaints, and site visits by the [District staff] indicate that the current [rule] is not sufficient to reduce PM_{10}

[487] A diameter of 327 m (greater than 1,000 ft): http://www.cargotransfer.net/pages/products/dome.php, (Commenter's Exhibit 99); Clear span domes over 900 ft. for bulk storage: http://www.cargotransfer.net/pages/products/adr04.php, (Commenter's Exhibit 100)
[488] South Coast Air Quality Management District, Rule 1158 - Storage, Handling, and Transport of Coke, Coal and Sulfur, adopted December 2, 1983, amended June 11, 1999; http://www.arb.ca.gov/pm/pmmeasures/ceffect/rules/scaqmd 1158.pdf, (Commenter's Exhibit 101).
[489] South Coast Air Quality Management District, Agenda No. 28 for Board Meeting, June 11; http://www.aqmd.gov/hb/1999/990628a.html, (Commenter's Exhibit 102)

emissions and the potential for public nuisances."[490] Thus, the SCAQMD adopted an updated rule that mandated enclosed storage for coke piles and broadened the rule to include coal and sulfur piles. This rule has been adopted into the SCAQMD's State Implementation Plan ("SIP"). The SCAQMD's experience is instructive as it shows that the methods proposed for the TEC as BACT do not always provide adequate dust control and that enclosed storage is feasible and the superior control option.

The SCAQMD further found that enclosures are a cost-effective way to reduce particulate emissions. The SCAQMD obtained costs to construct various types of enclosures and found that they ranged from $47/ton to $120/ton of enclosure capacity.[491] Further, enclosing piles reduces or eliminates the need for chemical encrusting agents or dust suppressants, which can be expensive and also have significant non-air quality health and environmental impacts[492] that must be considered in a top-down BACT analysis, but were not. Enclosure options are the top technology as they essentially eliminate storage piles emissions. Numerous examples are listed in the SCAQMD Staff Report for Rule 1158.

Recent permits and BACT analyses have required coal and coke storage to be enclosed. For example, the February 2009 BACT determination for the Southeast Idaho Energy facility, which will gasify coal and petcoke to produce fertilizer products, required coal and petcoke storage to be enclosed in silos vented to baghouses.[493]

The comment references the webpage of the company "Cargo Transfers" (refer to Commenter's Exhibits 99 and 100) in reference to this company's bulk storage dome product offerings which apparently include free-standing domes with diameters of up to 900 feet. An independent search for domes of this size in the United States resulted in a typical dome size ranging from 100-460 feet in diameter. A representative from Geometrica stated that they had never built a dome that spans 900 feet nor are they aware of any domes that large in the United States. A company referred to as "CST" advertises that domes can be built up to 1,000 feet in diameter; however, according to a representative from CST, the largest dome that they have built was less than 500 ft in diameter. CST is also not aware of a 900 ft dome being built for bulk storage. Therefore, it does not appear that a dome of the size required for the inactive storage pile is commercially available for the TEC, and regardless, USEPA has clearly stated in the response to comments for the Subpart Y NSPS that "the cost of requiring open coal storage piles to be enclosed is unreasonable." Based on these prohibitive costs and the small incremental PM emissions reductions that are achievable with storage domes as compared to the other effective control measures identified in the Subpart Y NSPS (including the application of chemical suppressants), USEPA did not determine "that complete enclosures with fabric filters constitute adequately demonstrated control

[490] South Coast Air Quality Management District, Final Staff Report for Rule 1158, p. ES-2; available as an attachment to Agenda No. 28 for Board Meeting, June 11; http://www.aqmd.gov/hb/1999/990628a.html, (Commenter's Exhibit 103)
[491] South Coast Air Quality Management District, Staff Report, Appendix D, p. D-1; available as an attachment to Agenda No. 28 for Board Meeting, June 11; http://www.aqmd.gov/hb/1999/990628a.html, (Commenter's Exhibit 104)
[492] Thomas Piechota and others., Potential Environmental Impacts of Dust Suppressants: "Avoiding Another Times Beach," An Expert Panel Summary, Las Vegas, NV, May 30-31, 2002, USEPA, EPA/600/R-04/031, March 2004, p. v. (Commenter's Exhibit 105)
[493] Idaho Department of Environmental Quality, Final Permit to Construct No. P-2008.0066, Southeast Idaho Energy, LLC, pdf 54, 67; available at http://www.deg.state.id.us/AlRlpermits forms/ptc final/se idaho energy power county ptc 0209 statement part.1.pdf, (Commenter's Exhibit 106)

technologies for open storage piles at this time."[494] As such, installing a storage dome over the inactive pile is not BACT for reducing PM emissions from the pile.

The comment also made the unfounded statement that a 60 day supply of coal for the inactive pile is excessive and that the typical storage quantity is 30 days. A maximum reserve coal supply of 60-days is not unreasonable given the potential for disruptions in the normal supply of coal to the plant due to either operational or labor problems at coal mine. CCG indicates that the design storage quantity for TEC was based on numerous economic and transportation related factors and was determined to be 60 days. A smaller storage pile could threaten interruptions in the coal supply that could also directly lead in a total shutdown of the gasification block. This would result in much larger quantities of PM emissions, as well emissions of other pollutants, from flaring and other units in the gasification block than the small reduction in PM emissions that would accompany a smaller inactive pile located in a full enclosure, as suggested by the comment.

In regards to the comment's reference to the South Coast Air Quality Management District (SCAQMD) rules that require the enclosure of all new coal, coke, or sulfur storage piles for sources in the greater Los Angeles area, the TEC does not fall under the jurisdiction of the SCAQMD rules. Further, a state implementation plan (SIP) requirement for sources in a non-attainment area does not establish BACT for sources located in attainment areas. [495] The referenced SCAQMD document states that the cost ranges from $30,000 per ton of PM_{10} reduced for a facility that needs to construct an enclosure to $3,000 for a facility that needs to improve housekeeping.[496] A cost estimate of $30,000 per ton of PM_{10} reduced for a facility in an area that is attainment for particulate is not considered BACT.

98. The BACT analysis failed to evaluate control effectiveness. The BACT analysis concluded that BACT was satisfied by "wet dust suppression" without assigning any control efficiency. The emission calculations, however, assumes a 50% to 90% control efficiency, depending upon the specific source. The control efficiency achieved by "wet dust suppression" depends upon the design of the program — the specific suppressant and binder, the application rate, the application frequency, the condition and characteristics of the surface to be controlled. These details should have been included in the BACT analysis, together with an estimated control efficiency to satisfy Step 3 of the BACT analysis.

The BACT analysis for all emission points associated with the inactive storage pile is justified and the Draft Permit contains conditions that will ensure ongoing compliance with the emissions limits. Part 4 of the BACT determination summary of the Project Summary requires that chemical suppressants (a surfactant that includes a binder) will be used on the pile to achieve a 90 percent control efficiency and the inactive chain reclaimer to the conveyor 4B transfer point (TP3) will achieve a 85 percent control

---

[494] **USEPA OAQPS, Standards of Performance for Coal Preparation and Processing Plants (40 CFR 60 Subpart Y) Response to Comments Received on Proposed Amendments (Published April 28, 2008; 73 FR 22901) and Supplemental Proposal (Published May 27, 2009; 74 FR 25304), September 2009, EPA-HQ-OAR-2008-0260-0150, Section 3.4.6.2.2, page 95.**

[495] **40 CFR 81.314**

[496] **South Coast Air Quality Management District, Agenda No. 28 for Board Meeting, June 11, 1999; http://www.aqmd.gov/hb/1999/990628a.html**

efficiency from inherent chemical latency. The other transfer point associated with the inactive pile requires wet dust suppression per Condition 4.3.2(d) of the permit to achieve 50 percent control efficiency. Roadway emissions require a dust control program, which includes an opacity limit and work practice standards (Conditions 4.11.2 and 4.11.5).

VI. THE DRAFT PERMIT WOULD NOT ADEQUATELY LIMIT POTENTIAL EMISSIONS OF HAZARDOUS AIR POLLUTANTS (HAPS)

99. In the Draft Permit, IEPA has found that the TEC is a minor source of HAPS, thus attempting to exempt this plant from maximum achievable control technology ("MACT") emission limits. There are two types of minor sources: (1) "genuine minor source" is one in which the potential to emit is below the major source threshold; (2) a "synthetic minor" source is one with potential emissions in excess of major source emission thresholds except that enforceable limitations on the source's potential to emit are imposed to keep the source from emitting at or above major source emission thresholds. As shown below, the draft permit violates the fundamental principles regarding the creation of minor permits, including synthetic minors, as the actual potential to emit exceeds the major source threshold and there are no permit conditions that will ensure that emissions of hazardous air pollutants from this facility will remain under major source thresholds. Since this facility unquestionably has the potential to emit HAPs in excess of major source HAP emission thresholds and the permit does not have enforceable limitations on the potential to emit that would ensure emissions remain below this threshold, IEPA cannot authorize construction of the TEC without issuing a MACT/NESHAP determination.

As explained below, the issued permit contains enforceable conditions limiting HAP emissions such that TEC is not a major source.

BACKGROUND ON THE REGULATION OF HAZARDOUS AIR POLLUTANTS

100. IEPA has proposed to issue a permit for the TEC that addressed the plant as a minor source for emissions of hazardous air pollutants (HAPs). This is because it claims that this plant is either a genuine minor source because the TEC's potential to emit HAPs is below the major source threshold or it is a synthetic minor source because permit conditions would limit its HAP emissions to less than major source HAP emission thresholds. However, the record and Draft Permit do not support these claims.

In general, the potential to emit (PTE) calculations for HAP emissions from the TEC project reasonable and adequately demonstrate that this plant should not be a major source for emissions of HAPs. The issued permit also contains requirements that are adequate to assure that the plant does not operate as a major source for HAPs. Accordingly, contrary to the claim by these comments, case-by-case MACT analyses and MACT determinations are not required for any emission units at the plant.[497]

[497] **Even assuming the plant as a whole constituted a major source of HAP emissions, a case-by-case MACT analysis would not be required for the power block, auxiliary boilers or emergency engines, as those emissions units would be covered by existing NESHAP standards.**

LEGAL REQUIREMENTS FOR RESTRICTING A SOURCE'S POTENTIAL TO EMIT

101. The definition of "potential to emit" requires first that the "potential to emit" of a source reflect its maximum capacity to emit a pollutant. Second, it requires that, to the extent that the owner or operator of the source or an agency claims that maximum capacity to emit is constrained in any way, a permit must explicitly set forth the constraint as a physical or operational limit - *e.g.*, a specific limit on fuel, hours of operation, or pollution control equipment operating parameters — that is federally and practically enforceable.

The definition of potential to emit in 40 CFR Part 63 is virtually identical to the definition of potential to emit in the PSD rules, 40 CFR 52.21(b)(4). Courts have interpreted the definition of potential to emit in 40 CFR 52.21(b)(4) to require restrictions on operating hours or production levels or types of material combusted, rather than simply imposing limits on tons of pollutants emitted per year. *See United States v. Louisiana-Pacific Corp.*, 682 F. Supp. 1122, 1133 (D. Colo. 1987) (blanket restrictions on actual emissions cannot be considered in determining potential to emit because these blanket emission restrictions, unlike limitations on hours of operation, fuel consumption, or production, "would be virtually impossible to verify or enforce.")

Courts have emphasized the need to ensure that any constraints assumed on potential to emit are grounded in enforcement reality. *See United States v. Louisiana-Pacific Corp.*, 682 F. Supp. 1122 (D. Colo. 1987); *Weiler v. Chatham Forest Products,* 392 F. Supp. 532, 535 (2d Cir. 2004) ("In short, then, a proposed facility that is physically capable of emitting major levels of the relevant pollutants is to be considered a major emitting facility under the Act unless there legally and practicably enforceable mechanisms in place to make certain that the emissions remain below the relevant levels").

Shortly after the *Louisiana-Pacific* decision discussed above, the USEPA issued policy on limiting potential to emit on June 13, 1989.[498] In this final guidance, USEPA specified requirements for properly limiting potential to emit. USEPA made it clear that, to be federally enforceable, limitations must be enforceable as a practical matter. USEPA stated that proper limits on potential to emit must include a production or operational limitation in addition to an emission limitation "where the emission limitation does not reflect the maximum emissions of the source operating at full design capacity without pollution control equipment."[499] Restrictions on production or operation would include limitations on amount of fuel combusted, hours of operation, or conditions which require the source to install and operate air pollution control technology to a specified emission rate or specified efficiency level. EPA stated that there are two exceptions to the prohibition on using blanket emission restrictions to limit potential to emit. One exception pertained to surface coating operations, and the other exemption applies when setting operating parameters for control equipment is infeasible. In such cases, a permit that includes "short term emission limits (*e.g.*, lbs per hour) would be sufficient to limit potential to emit, provided that such limits reflect the operation of the control equipment, and the permit includes requirements to install, maintain,

[498] USEPA Memorandum from Terrell E. Hunt to John S. Seitz with subject "Guidance on Limiting Potential to Emit in New Source Permitting" (June 13, 1989), (Commenter's Exhibit 107)
[499] *Id.* at 5-6.

and operate continuous emission monitoring ("CEM") system and to retain CEM data, and specifies that one can use the CEM data to determine compliance with emission limit.[500]

USEPA's 1989 guidance document also discussed "sham operation permits." Specifically, USEPA stated "permits with conditions that do not reflect a source's planned mode of operation are void ab initio and cannot act to shield the source from the requirement to undergo preconstruction review."[501]

Subsequent to the 1989 policies, USEPA issued a policy in January 1995 that discussed the various mechanisms available to create federally enforceable limits on HAP emissions.[502] Permitting programs approved under the SIP can only impart federal enforceability with respect to criteria pollutant emission limits. To create federally enforceable emission limitations for HAPs, the permitting program must be approved under Section 112(1) of the Clean Air Act. USEPA's January 25, 1995 guidance elaborated on prior policies including EPA's June 13, 1989 guidance on creating federally and practically enforceable limitations on potential to emit. These policies are still relied on today for determining whether permit conditions effectively limit potential to emit. *See, e.g.,* USEPA Objection to Proposed Title V Permit for Quebecor World Franklin located in Franklin, Kentucky (Aug. 29, 2002); *see also United States v. Questar Gas Mgmt. Co.*, 2:08-CV-167 TS, 2011 WL 1793172 (D. Utah 2011) ("the Court finds that, as it relates to the NESHAP regulations [HAP regulations], limitations on a facility's emissions may only be considered when they are legally and practicably enforceable by a governmental entity").

The state of Illinois developed a state operating permit program to, among other things, create federally enforceable limits on potential to emit. USEPA approved that program as part of Illinois' State Implementation Plan (commonly referred to as the "SIP") and under Section 112 of the Clean Air Act on March 7, 1995. 60 FR 12,478 (March 7, 1995). In that approval, USEPA reiterated the criteria of its July 28, 1989 Federal Register notice that permit limitations must create federally enforceable limitations on potential to emit. USEPA explicitly stated, it was "promulgating approval of Illinois' federally enforceable state operating permit program (FESOP) for the purposes of creating federally enforceable limitations on the potential to emit of Hazardous Air Pollutants (HAP) regulated under section 112 of the CAA. The USEPA is approving this program as meeting the criteria articulated in the June 28, 1989, Federal Register notice for State operating permit programs to establish limits federally enforceable on potential to emit and the criteria established in Section 112(1)." 60 FR 12,482; *see also* 35 IAC 211.2270, 35 IAC 211.4970. IEPA has proposed to issue the permit for the TEC pursuant to its state FESOP program.

These comments present a discussion of USEPA guidance on limiting potential emissions through permit conditions, and conclude that the limitations in the permit would not effective in limiting the TEC's emissions of HAPs. The IEPA disagrees with the conclusion.

[500] *Id.* at 8.
[501] *Id.* at 12.
[502] Memorandum from Kathie A. Stein to the USEPA Regional Air Division Directors with Subject "Guidance on Enforceability Requirements for Limiting Potential to Emit through SIP and § 112 Rules and General Permits." (Commenter's Exhibit 108)

USEPA has generally stated that limitations that are properly structured and enforceable are effective in limiting a source's PTE. *See generally,* Memorandum, dated January 25, 1995, from Kathie A. Stein, Director, Air Enforcement Division, to Director, Air and Pesticides and Toxics Management Division, Regions I and IV, *et al.*, entitled *Guidance on Enforceability Requirements for Limiting Potential to Emit through SIP and § 112 Rules and General Permits,* at 6-9. Permit limits for synthetic minor emissions, such as those addressed in the permit, are, in fact, a commonly used mechanism for limiting source-wide PTE. According to USEPA guidance, the critical issue is whether the permit terms limiting emission are practically enforceable.

Practically enforceable permit limits on PTE must: (1) provide a clear explanation of how the actual limitation or requirement applies; and (2) enable for the regulatory authority, the USEPA, and the public to ascertain compliance. *See, Sierra Club v. Public Serv. Co.*, 894 F. Supp 1455, 1460 (D. Colo. 1995)). USEPA has recognized that permit limits designed to be practically enforceable provide for a valid and effective constraint on a source's PTE. *See,* USEPA/Region 8 Objections to Proposed Title V Renewal Operating Permit for Big Stone Power Plant in South Dakota and cover letter, dated January 22, 2009 (recognizing that source-wide limits are sufficient to constrain PTE, provided that the limits are written with adequate compliance certification, testing, monitoring, reporting and recordkeeping requirements).

In this instance, the HAP emissions limits contained in the permit are consistent with the requirements in USEPA guidance and are therefore effective in limiting PTE for these pollutants. First, the emissions limitations are specific and accurate, as they clearly identify the pollutants that are limited and specify the numerical limits that must be achieved. *See, Guidance on Enforceability Requirements* at 6 (a permit limitation for PTE is specific and technically accurate if "a source is fairly on notice as to the standard it must meet"). In addition to the plant-wide single and combined HAP emission limits contained in Condition 3.4(a), the permit contains the following limits on HAP emissions: 1) plant-wide annual mercury emissions (Condition 3.4(b)), 2) annual methanol emissions from the AGR vent (Condition 4.1.6(a)), 3) annual COS emissions from the AGR vent (Condition 4.1.6(a)), 4) annual COS emissions from the flare (Condition 4.1.6(b)), 5) annual formaldehyde emissions from the combustion turbines (Condition 4.2.6(a) and Attachment 1 Table I), 6) annual hexane emissions from the coal dryers (Condition 4.3.6(d)), 7) annual hexane emissions from the auxiliary boiler (Condition 4.5.6), 7) annual methanol emissions from the methanol tank (Condition 4.8.6), 8) annual COS emissions from equipment leak components (Condition 4.9.5), and 9) annual methanol emissions from equipment leaks (Condition 4.9.5). These conditions likewise identify the regulated pollutants and specify the applicable emissions limitation.

In addition, the compliance period specified for the HAP emissions limits in the permit "readily allows for determination of compliance," as compliance is to determined monthly on a 12-month rolling basis. *See, Guidance on Enforceability Requirements* at 8 (stating that "EPA policy allows for rolling limits not to exceed 12 months or 365 days where the permitting authority finds that the limit provides an assurance that compliance can be readily determined and verified."). Moreover, the Permit includes

comprehensive and detailed compliance provisions for these emissions limitations, including requirements for testing, monitoring, recordkeeping, and reporting. *See,* Conditions 4.1.9(b)-(d), 4.1.10-2(b), 4.1.10-3(a), 4.1.10-4(f), 4.2.7(a)(i)(A), 4.2.10(d), 4.3.7-1(d), 4.3.10(f), 4.5.7(a), 4.5.9(g), 4.8.8(e), 4.9.6, and 4.9.7(c); *see also, See, Guidance on Enforceability Requirements* at 8 (observing that the method to determine compliance must "state the monitoring requirements, record keeping requirements, reporting requirements, and test methods as appropriate for each potential to emit limitation"). The compliance procedures for these emission limits apply to all periods of HAP emissions, including malfunctions.[503]

THE PLANT IS NOT A "GENUINE MINOR SOURCE"

102. The TEC would have the potential to emit HAPs. Emission points include the flare, the sulfur recovery unit ("SRU") and acid gas reduction ("AGR") unit vent in the gasification block; the combined cycle combustion turbines ("turbines") in the power block; and various other emission units at the plant. The IEPA finds that the TEC would not be a major source of HAPs because potential emissions from the plant would be less than the applicable thresholds of 25 tons per year in the aggregate for total HAPs and less than 10 tons per year for any single HAP. Accordingly, the IEPA finds that the plant is not subject to the National Emission Standards for Hazardous Air Pollutants ("NESHAPs"), adopted by USEPA under 40 CFR 63, that apply to major sources of HAPs. [504] The IEPA finds further that a case-by-case determination of maximum achievable control technology ("MACT") pursuant to Section 112(g) of the Clean Air Act is not needed for those emission units at the TEC that would not be subject to the NESHAP standards.

As demonstrated below, IEPA's conclusions are erroneous and based on severely flawed and not adequately supported emission estimates for HAPs. The Draft Permit then compounds these errors by failing to reflect the emission calculations in enforceable permit limits. When properly estimated, potential emissions of HAPs from the TEC by far exceed the major source thresholds for both single and total HAPs, making the proposed facility a major stationary source of HAPs and requiring MACT for all applicable sources.

The data for the plant's potential emissions of HAPs are not adequately supported. The IEPA does not provide a discussion of HAP emission estimates in the Project Summary and appears to have accepted CCG's emission estimates wholesale. Many of CCG's estimates for HAP emissions rely on emission factors from emission testing at other facilities, vendor-supplied information, or other studies that were not made available for public review. Thus, a considerable portion of CCG's emission estimates for HAPs are unsupported in the record. The following information, used by CCG to develop emission estimates for the TEC, was not made available:

— The metallic HAP content of coal, used to determine the raw and sweet syngas combustion emission factors for the flare and AGR and the SNG combustion emission factor

[503] Incidentally, the comment's discussion of USEPA's approval of Illinois' FESOP program as authority for the limitations on HAP emissions in the permit is not relevant. This is because a construction permit is being issued to the TEC. The FESOP program is a means to establish limits on emissions of regulated pollutants from existing sources, that are already in operation. The authority for provisions in the permit that limit HAP emissions arise from the Illinois's various sources of authority for issuance of construction permits.

[504] Project Summary, p. 20; Draft Permit, p. 3.

for the CCCTs, flare, methanation startup heater, SRU thermal oxidizer, auxiliary heater and boiler was allegedly based on metals sampling data for Herrin Illinois coal provided by the Illinois State Geological Survey (ISGS). This dataset is not provided. Instead, the Application provides an inactive weblink to the ISGS coal quality database. [505] Further, the Application provides no discussion whatsoever why the HAP content of Herrin Illinois coal is deemed representative for the coal that the TEC would gasify as the Draft Permit does not contain any conditions limiting the facility to Herrin Illinois coal. (*See* discussion above regarding the enforceability comment on coal origin.)

— The metallic HAP conversion rate for coal-to-raw syngas, used to determine combustion emission factors for syngas, was allegedly based on a "pilot scale test of Illinois coal to raw syngas ... performed by gasifier vendor for all metals except mercury."[506] This pilot-scale test performed by the gasifier vendor was not provided for review.

— The removal rate of the carbon absorption beds for mercury (90%) used to determine emission factors for syngas and SNG, was allegedly based on the "design removal efficiency."[507] The record contains no information on the vendor of the carbon absorption beds, design specification sheets, or other any other information that would support a design removal rate of 90%.

— The removal efficiency of the syngas conditioning train for hydrogen fluoride (99%), used to determine hydrogen fluoride combustion emission factors for syngas and SNG, was allegedly "predicted by heat and material balance data for fluorides."[508] These heat and material balances were not provided in the record.

— The non-metallic HAP combustion emission factors for syngas, used to determine emissions from the flare and AGR, were allegedly based on field data collected at the Louisiana Gasification Technologies Incorporated ("LGTI") facility in November 1995 as presented in the October 16, 1996 *Summary Report: Trace Substance Emissions from a Coal-Fired Gasification Plant* prepared by Radian International, LLC for the Electric Power Research Institute ("EPRI") and the U.S. Department of Energy ("DoE")."[509] This report was not provided in the record.

A public records request was submitted to IEPA asking for all information related to the Draft Permit but were not provided with any of the above information.

In *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, PSD Appeal Nos. 99-4 & 99-5, 2000 WL 833062 (June 22, 2000), the EAB remanded the permit back to the state agency after finding that the state agency's PTE evaluation was inadequate because the agency did not include explanations of the underlying basis for its calculations and the public record contained no documents supporting its conclusion. Without this information, the EAB determined that it was unable to determine whether or not the significance level for a given pollutant would be exceeded and, thus, whether BACT for lead should be installed at this facility. Moreover,

[505] *See* Ap., Footnote A to Appx. C, Table C-22-2.
[506] *See* Ap., Footnote B to Appx. C, Table C-22-2.
[507] See Ap., Footnote C to Appx. C, Table C-22-2.
[508] *See* Ap., Footnote C to Appx. C, Table C-22-2.
[509] *See* Ap., Footnote 1 to Appx. C, Table C-22-3.

the Board remanded the permit back to the state agency because it failed to consider detailed comments regarding an alternative calculation for potential to emit submitted by a commenter. The comments had articulated how the agency had underestimated the facility's emissions of lead and other hazardous air pollutants, erroneously failed to consider all potential sources of lead emissions, and finally presented its own calculated PTE after correcting for these deficiencies.

This Draft Permit is similar to the Steel Dynamics permit as IEPA's potential to emit evaluation for HAPs is inadequate, cursory, and not supported by documents in the record. Moreover, this comment describes in detail below how emissions were underestimated. I also provide my own potential to emit for HAPs after correcting for these deficiencies.

As discussed elsewhere, sufficient information is contained in the permit record to support the emissions calculation for HAP emissions relied upon by the issued permit.

103. The emission calculations for HAPs are arbitrary and substantially underestimate potential emissions. The IEPA does not appear to have conducted independent emission calculations for the TEC. Instead, it appears to have relied entirely on CCG's estimates of potential HAP emissions contained in the Application, Appendix C, to come to its conclusion that the facility is not a major source of HAPs. I requested from IEPA a copy of the 111 pages of spreadsheets contained in Appendix C in their native Excel format. Apparently, IEPA is not in possession of the requested information. This casts serious doubt on the thoroughness of IEPA's review of CCG's emission calculations as it is exceedingly difficult and time-consuming to wade through 111 pages of spreadsheets in PDF format and understand not only how these spreadsheets are linked to each other but also how individual emission factors were derived and emissions were calculated. I spent dozens of hours "re-engineering" these spreadsheets to understand CCG's emission calculations. Based on my review, and as discussed below, CCG's derivation of HAP emission factors is arbitrary and not adequately supported. As a result, the resulting estimates of potential HAP emissions are erroneous and fail to establish that the TEC is a genuine minor source of HAPs. Further, as discussed above, the permit limits established based on these unsupported emission estimates are unenforceable as a practical matter and thus do not assure that minor source status is actually achieved and maintained.

CCG provided the IEPA with sufficient information to make an informed decision as to the potential HAP emissions from the TEC. Pursuant to 40 CFR 52.21(r)(1), a permittee is required to construct and operate the source consistent with the application. Moreover, the applicant must certify that the information provided in the application is true and accurate. *See* 199-CAAPP Form. Moreover, where emissions are effectively limited by a permit, PTE calculations have no bearing. The enforceable permit limitations establish the PTE in those instances.

104. The emission data provided by CCG substantially underestimate HAP emissions from fugitive equipment leaks. I calculated the impact of equipment leak emission factor selection on the HAP emission inventory. This analysis, included in Commenter's Exhibit

19, indicates that total HAP emissions would increase from 19.24 ton/yr[510] to 25.91 ton/yr if the "with ethylene" SOCMI factor were used and to 29.2 ton/yr if USEPA's average refinery emission factors were used. This increase is due to increases in emissions of methanol and COS. The total HAP emissions would be even higher if other errors in the HAP emission calculations discussed in my comments were corrected.

Thus, selection of emission factors alone determines the HAP major source status of this facility. As no monitoring at all is required to confirm that the assumptions used to estimate equipment leak emissions are actually met, the most conservative estimate of emissions should be used to determine HAP major source status.

For the reasons previously discussed with respect to criteria pollutant emissions from equipment leaks, HAP emissions from equipment leaks are not underestimated. The comment's recalculation of HAP emissions based on TCEQ's SOCMI with ethylene emission factors are not appropriate because the process streams at the TEC will not contain ethylene. As described in TCEQ's equipment leak permitting guidance document (Commenter's Exhibit 23), the SOCMI with ethylene emission factors are reserved for "components in service of material which is greater than 85% ethylene," and these factors are, therefore, not applicable to the TEC's process streams.[511] The comment's use of USEPA's refinery average factors to recalculate HAP emissions from equipment leaks are equally inappropriate.

As discussed previously, actual HAP emissions from equipment leak components will be primarily calculated based on the results of LDAR monitoring and not based on the SOCMI without ethylene emission factors. The uncontrolled annual potential total HAP emissions from ELC included in the LDAR program is 19.5 tpy, and the uncontrolled annual potential total HAP emissions from ELC not included in the LDAR program is only 1.2 tpy (refer to Sections C-24 to C-27 of Appendix C). This data indicates the vast majority of components with significant concentrations of total HAP emissions will be controlled by an LDAR program, and thus will have actual HAP emissions calculated based on the measured concentrations from the periodic LDAR monitoring. The remaining components not subject to an LDAR program will, however, use the SOCMI without ethylene emission factors. Relying on a representative ELC emission factor for components not controlled by an LDAR program is an acceptable approach recommended by USEPA, as discussed elsewhere. Based on a combination of monitoring data and emission factors, CCG will be able to determine the actual HAP emissions from ELC for inclusion in the assessment of plant-wide HAP emissions to demonstrate compliance with the HAP limits in Condition 3.4 of the permit.

105. Emissions of methanol are underestimated. The TEC would have a Rectisol®-based acid gas removal unit to selectively separate sulfur compounds and CO_2 from the syngas. The Rectisol® absorber will utilize chilled methanol as a physical solvent. A 903,370-gallon storage tank with an annual turnover of 2,030,000 gallons per year ("gal/year") would

[510] Ap., v. 1, Appx. C, p. C-87, Table C-23.
[511] **Commenter's Exhibit 23, p. 4.**

supply makeup methanol to the AGR.[512] Based on a density of 6.6 lb/gal for methanol, the annual throughput of methanol can thus be calculated at 6,699 ton/yr.[513]

Although the Draft Permit quantifies the maximum annual makeup (turnover) of methanol, the losses of methanol permitted by the Draft Permit and quantified by the underlying Application do not total 6,699 ton/yr. Emissions of methanol are identified in Appendix C to the Application and were easily totaled. Some of the methanol that is lost is combusted (and converted to CO_2 and water). Other emissions occur via fugitive sources, where the methanol is directly emitted to the atmosphere through evaporation and leaks. Both types of losses are accounted for in the Application from six sources, specifically, the methanol tank, flare, sulfur recovery unit, acid gas removal unit, gasifier process area, and fugitive equipment leaks. The following summarizes uncontrolled losses of methanol from each of these sources.

Methanol tank: Because losses from the methanol tank as VOM consist entirely of methanol, which is a HAP, all fugitive losses from the methanol tank must be accounted for in the HAP emission estimates. The Application, Appendix C, estimates 0.11 ton/yr fugitive losses for an internal floating roof tank with the USEPA's TANKS model.[514] Tank emission factors calculated by this model assume that the floating tank roof is always floating and thus does not include roof landing losses. However, when the floating roof is landed, large amounts of VOCs are expelled. CCG recognized that these losses were not included in the application's emission estimates for the methanol tank and submitted a supplemental calculation for tank landing emissions.[515] The total losses of methanol during roof landing, which consist of standing idle losses and filling losses, were estimated at 0.097 ton/yr.[516] Thus, total losses from the methanol tank can be estimated at 0.21 ton/yr. Condition 4.8.6 of the Draft Permit allows total annual emissions of 0.25 tons from this tank, including roof landing losses, 0.4 ton/yr more than estimated by CCG. IEPA does not provide an explanation for this discrepancy.

Flare: The application estimates pre-flare (uncontrolled) emissions during a flare cold plant startup at 2.57 ton/yr. Uncontrolled emissions during total plant shutdown are estimated at 0.28 ton/yr.[517] Thus, total uncontrolled emissions from the flare are 2.85 ton/yr.

Sulfur recovery unit: The Application estimates controlled methanol emissions from the sulfur recovery unit thermal oxidizer during plant cold startups at 0.000861 tons/yr and a control efficiency for methanol of the thermal oxidizer of 99%.[518] Based on this information, uncontrolled losses of methanol routed to the thermal oxidizer would b 0.09 ton/yr.[519]

[512] Ap., pp. 2-10, 2-14, and 10-1 and Draft Permit, Cond. 4.8.5.b.
[513] (2,030,000 gal/year) x (6.6 lb methanol/gal) x (1 ton/2,000 lb) = 6,699 tons methanol/year.
[514] Ap., Appx. C, Table C-18.1, pp. C-63 - C-64.
[515] Email from Larry Carlson, Tenaska, to Chris Romaine and Robert Smet, September 15, 2011, Attachment: MEOH Tank Landing Emissions Calculations v.1.0.pdf (provided by IEPA in response to FOIA request), (Commenter's Exhibit 109)
[516] (194.8 lb/event) x (1 event/year) x (1 ton/2000 lb) = 0.097 ton/yr.
[517] Ap., Appx. C, Tables C-3.3 and C-3.4, p. C-11.
[518] Ap., Appx. C, Table C-4.4, p., C-23, and C-22.
[519] (8.61E-04 ton/yr) x (100/1) = 8.61E-02 ton/yr.

Acid gas removal unit: CCG provided an estimate for total controlled emissions from the AGR CO_2 vent stream during normal operations of 2.63 ton/yr and of 0.05 ton/yr during cold startups.[520] Thus, controlled emissions of methanol from the AGR unit total 2.68 ton/yr.

The CO_2 product vent stream from the AGR train will be routed to a dedicated thermal oxidizer.[521] Based on the control efficiency of this thermal oxidizer, 90%, uncontrolled losses of methanol attributable to the AGR process area can be estimated at 26.8 ton/yr.[522]

Gasifier coal bunker vent: The Application estimates a total of 0.3 ton/yr of methanol losses through the gasifier coal bunker vent.[523]

Fugitive equipment leaks: The Application provides estimates of uncontrolled methanol losses from the hundreds of individual components including valves, pumps, compressors, PRVs, connectors, open ended lines, and sample connectors in the various process areas of the plant including the gasification/syngas conditioning area (0.00663 tons/yr), the AGR process area (0.0173 tons/yr), the SRU process area (0.0036 tons/yr), and miscellaneous other process areas (0.0683 tons/yr).[524] These fugitive emissions add up to a total of 0.16 ton/yr of methanol losses. Elsewhere, the Application estimates a total of 1.0 ton/yr of methanol emissions from fugitive equipment leaks.[525]

Total methanol losses: Summarizing uncontrolled and controlled emissions from the above discussed six sources and respective permit conditions, where applicable, the Application accounts for a total loss of 31.29 ton/yr of methanol from the six identified sources.[526] When comparing these facility-wide emissions with the annual methanol makeup, there is a discrepancy of 6,668 ton/yr (the difference between the amounts of methanol added to the tank every year (6,699 ton/yr) minus the amounts identified as lost (30.56 ton/yr). Because the identified losses amount to less than 0.5% of the amount of methanol make-up,[527] it is clear that there is some other unidentified source(s) of methanol losses.

If this amount of methanol were directly emitted somewhere in the plant, it would constitute an enormous additional source. As discussed elsewhere in this comment letter, CCG substantially underestimated fugitive equipment leaks, which explains some of the unaccounted-for methanol losses. However, even if the entire unaccounted-for quantity of methanol of 6,668 ton/yr were burned and sent up a stack with 99% combustion efficiency, emissions would still amount to about 67 ton/yr.[528] Thus, even under the best-case scenario, the unaccounted-for emissions of methanol render the facility a major source of HAPs.

All methanol emissions were accounted for. The comment mischaracterized the quantity of "make-up" methanol that will be fed to the Rectisol® AGR unit. The 2.03

[520] Ap., Appx. C, pp. C-26 to C-27 and p. C-30 and Table C-5.4, p. C-30.
[521] Ap., Appx. C, pp. C-26 to C-27.
[522] (2.68 ton/yr) x (100/10) = 26.8 ton/yr.
[523] Ap., Appx. C, p. C-43.
[524] Ap., Appx. C, pp. C-104 to C-110.
[525] Ap., Appx. C, Table C-23.1, p. C-87.
[526] The methanol emission data discussed by this comment were summarized in the Commenter's Table 16.
[527] (31.29 ton/yr)/(6,699 ton/yr) = 0.0047.
[528] (6,668 ton/yr) x (1-0.99) = 66.68 ton/yr.

million gallon per year feed to the methanol tank includes 637,247 gallons per year for de-inventorying the recirculating methanol within the AGR during a total plant shutdown. This methanol removed from the AGR unit will be charged backed to the system during the cold plant startup following the total plant shutdown. As stated in Section C-18 of Appendix C to Volume 1 of the Application, the make-up rate to the methanol tank is 3,705 gallons per day (or 1.35 million gallons per year and 4,463 tpy).

The comment's quantification of uncontrolled methanol emissions is incorrect,[529] but more importantly ignores the non-air fate for most of the methanol fed to the AGR unit. First, some of the methanol is transferred into the syngas that is then fed to the Methanation Unit. In the Methanation Unit, this methanol gets converted to methane and becomes SNG. Methanol is also present in the acid gas fed to the Claus SRU. Any methanol in the acid gas feed to the SRU gets destroyed in the Claus thermal reactor, and any uncombusted methanol present in the SRU tailgas would get destroyed in the SRU thermal oxidizer.[530] Finally, a fraction of the methanol circulating in the AGR unit is bled off and fed to the gasifiers (refer to Sections 2.2.3 and 2.2.5 of Volume 1 to the Application) to be converted into syngas.

These types of non-air fates for methanol within the gasification block are similar for any facility that uses a Rectisol® AGR unit. Routing methanol from the AGR unit to other process areas within the TEC either intentionally as a recycle stream (as in the case of the recycle stream to the gasifiers) or unintentionally as a trace contaminant in a product stream (as in the case of the shifted syngas and acid gas) does not mean that these other processes will vent the methanol they receive to the atmosphere. Because the gasification block is a chemical manufacturing facility, a simplistic methanol mass balance approach, as used in this comment, does not adequately address the fate of methanol and is inappropriate in assessing methanol emissions from the TEC.

106. The HAP emissions from the power block are underestimated. The power block would have two combined cycle combustion turbines (CCCTs) and a single heat recovery steam generator which will not have duct burners. The CCCTs would fire either SNG from the gasification block or pipeline natural gas. To estimate HAP emissions from the CCCTs, the

---

[529] **The comment claims that methanol emissions were underestimated based on an attempt to quantify uncontrolled methanol emission from all of the methanol sources at the TEC. That quantification is incorrect for the methanol tank and equipment leak components. For the methanol tank, Condition 4.8.6 of the Draft Permit does cite an incorrect VOM and methanol emission limit for the methanol tank. The basis of the incorrect 0.25 tpy value was 0.11 tpy from the internal floating roof TANKS run to capture normal breathing and working losses from the tank and 0.14 tpy from the roof landing loss calculations. The 0.14 tpy was calculated as the sum of total landing losses (0.097 tpy) and standing idle losses (0.046 tpy) when it only should have included total landing losses. Standing idle losses are already included in the total landing losses. This discrepancy does not affect the HAP source classification of the TEC but was corrected in the issued permit. For the equipment leak components, the comment failed to include the uncontrolled methanol emissions from components subject to the LDAR program in their incorrect estimates of plant-wide uncontrolled methanol emissions from ELC. The uncontrolled annual potential methanol emission rates from ELC controlled by the LDAR program in each process area can be calculated based on the total uncontrolled fugitive emission rate in ton per year multiplied by methanol composition provided in Sections C-24 to C-27 of Appendix C to Volume 1 of the Application. For example, as shown in Section C-25, the total uncontrolled fugitive emissions from components controlled by the LDAR program in the AGR process area are 23.10 tpy and the average methanol composition of the process streams in this area is 66.75% by weight, which gives a total uncontrolled methanol emission rate of 15.42 tpy. When added to the other uncontrolled methanol emission rates for components controlled by the LDAR program, the correct uncontrolled plant-wide annual potential methanol emission rate from equipment leaks is 19.20 tpy. When making these corrections, the plant-wide uncontrolled annual potential methanol emission rate for the TEC is 49.45 tpy and not 31.29 tpy as suggested by the comment.**

[530] **The very high methanol destruction efficiency achieved in the Claus unit thermal reactor is supported by the very low uncontrolled methanol emission rate from the SRU thermal oxidizer (i.e., 0.09 tpy) which also is equivalent to the amount of methanol that is present in the SRU tailgas.**

Application developed HAP emission factors for combustion of SNG and natural gas for both normal operations and startup/shutdown of the CCCTs. As discussed below, CCG's approach to HAP emission factors is problematic and substantially underestimates potential emissions from the power block. In fact, HAP emissions from the power block alone would be enough to make the TEC a major source of HAPs.

Substitute natural gas (SNG) is not guaranteed to have the same combustion characteristics as natural gas. CCG derived emission factors for various HAPs, including acetaldehyde, acrolein, benzene, formaldehyde, and polyaromatic hydrocarbons ("PAH"), based on USEPA's *Compilation of Air Pollution Emission Factors* ("AP-42"), Chapter 3. 1, Stationary Gas Turbines, for uncontrolled natural gas-fired turbines. All other organic HAP emission factors were based on AP-42, Chapter 1.4 for External Natural Gas Combustion.[531] Neither CCG nor the IEPA provides a satisfactory explanation why emission factors derived for natural gas-fired combustion sources (and especially for heaters and boilers) are considered applicable to combustion of SNG in the turbines at the TEC. In its engineering evaluation, the IEPA provides several definitions for natural gas based on 40 CFR 60.41Da, 40 CFR 60.41b, 40 CFR 60.41c, 40 CFR 60.331(u), 40 CFR 60.4420, and 40 CFR 72.2.[532] Despite the fact that every one of these definitions defines "natural gas" as a "naturally occurring" mixture of hydrocarbons, the IEPA finds that it considers SNG equivalent to natural gas because it will meet the most stringent physical and chemical specification of any of these definitions including a higher heating value between 950 and 1,100 British thermal units per standard cubic foot ("Btu/scf') and a maximum fuel sulfur content of 0.5 grains of total sulfur per 100 scf. In addition, IEPA finds that SNG has much higher methane purity than pipeline natural gas and does not contain any longer chain hydrocarbons that are either directly emitted post-combustion as VOM or form VOM through secondary reactions. Since the SNG produced by the TEC would meets all physical and chemical specifications of natural gas and, with respect to "some" regulated air pollutants, is expected to produce less combustion byproduct emissions than natural gas, IEPA finds that it is appropriate to use natural gas emission factors for all SNG combustion at the plant.[533] These arguments are not convincing.

First, while the SNG may have similar physical and chemical characteristics compared to pipeline natural gas, the two gases are just that, similar, but not identical. SNG may have a similar heat content, maximum sulfur fuel content, and higher methane content as natural gas but may have a different content of other components that affect the combustion process and the formation of pollutants.

Second, the Draft Permit does not contain a requirement that SNG be consistently produced to the specifications assumed by IEPA. While Condition 4.2.7 of the Draft Permit would require analysis of the sulfur content (including total sulfur, H_2S, COS, and CS_2), chlorine, fluorine, metals, VOM and methanol of SNG, it would not require analysis for CO, methane, hydrogen, or moisture content or the heating value of the SNG, all of which affect the combustion process and the formation of combustion products including HAPs.

[531] Ap., p. 12-3 and Appx. C, Table C-23, p. C-88.
[532] Project Summary, p. 3-8.
[533] Project Summary, p. 3-9.

Based on current definitions of natural gas in the NSPS, the SNG planned to be produced by TEC is natural gas as explained in further detail elsewhere.[534] As demonstrated in Table 3-3 of Volume I of the Application, SNG meets the methane content and heating value requirements under the regulatory definition of natural gas and it may have a higher methane content than the pipeline natural gas available for use at the TEC.[535] Unlike natural gas, SNG because of the way it is produced does not contain ethane, propane, butane, isobutane, pentane, or hexane which are all may be present in natural gas. Emissions of organic and inorganic HAPs from natural gas combustion are largely dependent on the chemical composition of the fuel. The presence of longer chain hydrocarbons in the fuel can lead to direct VOM/HAP emissions from incomplete combustion of the VOM and HAP species in the fuel or to indirect VOM/HAP emissions through secondary reactions that are more likely to occur when complex longer chain hydrocarbon molecules are present in the fuel. Therefore, SNG is expected to have *lower* VOM and HAP emissions as byproducts of combustion, thus it is conservative to apply emission factors derived for natural gas-fired combustion sources to the combustion of SNG. [536]

AP-42 is widely accepted as an appropriate source of emission factors for natural gas combustion throughout the United States, despite significant variation in natural gas compositions, because it is often the best available method for estimating emissions. There were no other emission factors that were more representative of emissions from the proposed SNG combustion sources at the TEC, and the comment does not propose an alternative emission calculation approach. Since SNG has a higher chemical purity than natural gas, and AP-42 factors are considered appropriate for a wide range of natural gas compositions, the AP-42 factors are appropriate for SNG.

---

[534] **This comment incorrectly states that all of the relevant definitions for natural gas cited in the application require it to be "naturally occurring." The definitions of natural gas cited in the application from NSPS Subparts Da, Db, and Dc, state that natural gas can be a naturally occurring mixture of hydrocarbons OR a mixture of hydrocarbons (with no specified origin) that maintains a gaseous state at ISO conditions and is composed of at least 70 percent methane by volume or has a gross calorific value between 910 and 1,150 Btu per dry standard cubic foot. Note, however, that the definitions of natural gas in Subparts Da, Db, and Dc were revised as part of the Utility MATS rulemaking effort and it is those definitions that are appropriately considered in the responses to this and other comments regarding the status of the SNG.**

[535] **Application Volume I, Table 3-3, page 3-9.**

[536] **The comment points out that SNG and pipeline natural gas are similar but not identical, suggesting that the differences in composition will affect the combustion process and emissions of pollutants, without suggesting any likely (or even plausible) mechanisms of how this might occur. While pipeline natural gas and SNG are not identical, pipeline natural gas also varies in its composition depending upon its source(s). As shown below, the composition of natural gas can vary significantly from one production field to another. It can also vary over time even within the same field. Natural Gas Supply Association, Overview of Natural Gas, Background, available at http://www.naturalgas.org/overview/background.asp**

Table 3. Typical Composition of Natural Gas

Methane	CH_4	70-90%
Ethane	C_2H_6	0-20%
Propane	C_3H_8	
Butane	C_4H_{10}	
Carbon Dioxide	CO_2	0-8%
Oxygen	O_2	0-0.2%
Nitrogen	N_2	0-5%
Hydrogen sulphide	H_2S	0-5%
Rare gases	A, He, Ne, Xe	trace

Methane, hydrogen, carbon monoxide, and moisture content monitoring for the SNG are not necessary to ensure a consistent supply of SNG to the combustion turbines. The carbon monoxide, hydrogen, and water content of the sweet syngas feed to the methanation unit are critical process variables that will be continuously measured and controlled by CCG to ensure a high SNG yield. Redundant air permit conditions that require this monitoring is unnecessary since the normal operation of the methanation unit in a manner to maximize SNG yield and the profitability of the site will ensure the composition of the sweet syngas and SNG are maintained within a very narrow range which is well within the regulatory limits for meeting the definition of natural gas. Furthermore, the pipeline specifications for SNG negotiated with the pipeline operators will not allow for excessive amounts of carbon monoxide or moisture in the SNG product, so the composition of these constituents must be carefully controlled to ensure the SNG meets the pipeline specifications at all times. Controlling the chemical composition of the sweet syngas feed to the methanation unit and the resulting SNG produced, as discussed above, will simultaneously ensure the SNG has a heating value within the 950 to 970 Btu/scf range specified in Table 3-3 of the Application. Despite the comment's suggestions to the contrary, including operating limits on process variables that are addressed as part of the normal operating practices of the plant is unnecessary.

107. The CO ratio scaling approach used by CCG is not supported. Rather than using the emission factors provided in AP-42, Chapter 3.1, as given, CCG scaled each emission factor by "the ratio of the uncontrolled CO emission factor for diffusion flame combustion turbines to the lean premix CO emission factor to reflect the greater combustion control and resulting lower organic HAP emissions that are expected from lean premix combustion turbines."[537] The following formula illustrates the CCG's ratio calculation:

$$EF_{HAP\ Draft\ Permit} = (EF_{HAP\ AP\text{-}42,\ Ch.\ 3.1}) \times (EF_{CO\ Draft\ Permit}) / (EF_{CO\ AP\text{-}42,\ Ch.\ 3.1})$$

where
$EF_{HAP\ Draft\ Permit}$ = emission factor for HAP used in Draft Permit
$EF_{HAP\ AP\text{-}42,\ Ch.\ 3.1}$ = average emission factor for HAP from AP-42, Chapter 3.1, for uncontrolled natural gas-fired turbines at high load (>80%)
$EF_{CO\ Draft\ Permit}$ = emission factor for CO at full load (0.0094 lb/MMBtu)
$EF_{CO\ AP\text{-}42,\ Ch.\ 3.1}$ = average emission factor for CO from AP-42, Chapter 3.1, for uncontrolled natural gas-fired turbines at high load (>80%) (0.082 lb/MMBtu)

Based on this ratio calculation, the emission factors used in the Draft Permit to estimate potential HAP emissions from the TEC burning SNG amount to only 11.5% of the emission factors for combustion of natural gas provided by AP-42, Chapter 3.1.[538] Neither the application nor the Project Summary provides any explanation or justification for using this ratio. There are a number of problems with this approach.

First, CCG supplies no support whatsoever for the CO emission factor of 0.0094 pounds per million British thermal units ("lb/MMBtu") for full load, which was used to scale the AP-42

[537] Ap., p. 12-3, and Appx. C, Footnote A to Table C-23, p. C-91.
[538] (0.0094 lb/mmBtu) / (0.082 lb/mmBtu) = 0.115.

HAP emission factors for uncontrolled turbines at high load (>80%). Allegedly, this CO emission factor has been provided by the turbine vendor[539] but neither a vendor guarantee or a demonstration of this emission factor was provided.

Second, the USEPA in AP-42, Chapter 3.1 for stationary gas turbines explicitly points out that "[i]t is recognized that the uncontrolled emission factor for CO is higher than the water-steam injection and lean-premix emission factors, which is contrary to expectation. The EPA could not identify the reason for this behavior, except that the data sets used for developing these factors are different."[540] For this reason alone, the use of the CO ratio scaling approach as used by CCG is not justified.

Third, it is well known that, similar to CO emissions, HAP emissions increase with reduced operating loads. Turbines are designed to run efficiently at full load where fuel combustion is nearly 100 percent efficient. At lower loads, and during startup, turbines are extremely inefficient[541], which results in incomplete combustion.[542] This increases products of incomplete combustion, such as CO, aldehydes, and hydrocarbons.[543] However, the relationship is not necessarily directly proportional and differs for individual HAPs as well as with the type of turbine. Neither CCG nor the IEPA provide a demonstration that emissions of individual HAPs increase or decrease at a 1:1 ratio with CO emissions at different loads.

Based on the average emission factor for formaldehyde provided in USEPA's AP-42, Chapter 3.1 (without scaling), emissions from the two turbines during normal operations alone (8,528 hours/year without even accounting for startup and shutdown emissions), can be calculated at 13.6 ton/yr.[544] Thus, when relying on the average emission factor given in AP-42, formaldehyde emissions from normal operations of the turbines alone exceed the threshold for single HAPs of 10 ton/yr and render the facility a major source. Based on the (unmodified) average emission factor for toluene provided in AP-42, Chapter 3.1, toluene emissions from normal operations of the turbines account for an additional 2.5 ton/yr.[545]

Site specific data is appropriate to use when available to estimate emissions. Such data was used by CCG in combination with emission factors from AP-42. As pointed out in the comment, USEPA has even acknowledged that the uncontrolled CO emission factor in AP-42 for diffusion flame combustion turbines is higher than the CO emission factor for lean premix turbines, which should be considered when estimating organic HAP emissions from the lean premix turbines.

The AP-42 Chapter 3.1 HAP emission factors are not appropriate to use directly for the TEC's combustion turbines. The sum of the organic compound emission factors in Table 3.1-3 of AP-42 (0.0010 lb/MMBtu) is nearly equivalent to the maximum heat

[539] Ap., Appx. C, Footnote 2 to Table C-8.1, p. C-34.
[540] AP-42, Chapter 3.1, Footnote c to Table 3.1-1.
[541] R. H. Kehlhofer, J. Warner, H. Nielsen, and R. Bachmann, Combined-Cycle Gas Steam Turbine Power Plants, 2nd Ed., PennWell, Tulsa, OK, 1999, Chapter 8: Operating and Part Load Behavior.
[542] A. H. Lefebvre, Gas Turbine Combustion, 2nd Ed., Taylor & Francis, Philadelphia, PA, 1998, Sec. 9-4, Mechanisms of Pollutant Formation.
[543] Gas Research Institute ("GRI") and Electric Power Research Institute ("EPRI"), 1996. Gas-Fired Boiler and Turbine Air Toxics Summary Report. Prepared by Carnot Technical Services for GRI and EPRI, August 1996, (Commenter's Exhibit 138)
[544] (0.00071 lb formaldehyde/mmBtu) x (2,250 mmBtu/turbine/hr) x (2 turbines) x (8,528 hours normal operation/year) x (ton/2,000 lb) = 13.62 t/yr.
[545] (0.00013 lb toluene/mmBtu) x (2,250 mmBtu/turbine/hr) x (2 turbines) x (8,528 hours normal operations/year) x (ton/2,000 lb) = 2.49 tons/year.

input-based VOC emission rate from the combustion turbines (0.0013 lb/mmBtu) while AP-42 Chapter 3.1 suggests that the Table 3.1-3 compounds should comprise less than 50 percent of the total VOC uncontrolled emissions (0.0010 lb/mmBtu from Table 3.1-3 divided by 0.0021 lb/mmBtu VOC from Table 3.1.2a). In addition, the uncontrolled CO emission rate from Table 3.1-1 for natural gas-fired turbines (0.082 lb/mmBtu) is more than eight times higher than the maximum heat input-based CO emission rate from the vendor for the TEC combustion turbines (0.0094 lb/mmBtu).[546] This simple comparison of the CO, VOC, and organic HAP emissions data from AP-42 to the expected performance of the TEC's combustion turbines on a worst-case basis for normal steady-state operation at loads above 60 percent clearly shows that there is a disconnect between the AP-42 data and the TEC's emission estimates which must be addressed when attempting to quantify the potential HAP emissions from the combustion turbines.

Scaling the AP-42 Table 3.1-3 emission factors by the ratio of the TEC's worst-case heat input-based CO emission rate to the Table 3.1-1 uncontrolled CO emission factor is appropriate and is consistent with USEPA's common practice of using CO as a surrogate for organic HAP emissions in recent NESHAP rule development for combustion units.[547]

This approach is further justified when considering the additional supporting information provided below which suggests that the resulting formaldehyde emission factor calculated based on this approach is consistent with test results from studies of organic HAP emissions conducted more recently than the studies supporting the development of AP-42 Chapter 3.1 and conducted on turbines that are more representative than the smaller, older, and higher emitting turbines used to develop AP-42 Chapter 3.1.

The comment cites the following statement in AP-42 Chapter 3.1 to further support the argument that the CO ratio scaling approach is not appropriate:

> **[I]t is recognized that the uncontrolled emission factor for CO is higher than the water steam injection and lean-premix emission factors, which is contrary to expectation. The EPA could not identify the reason for this behavior, except that the data sets used for developing these factors are different.[548]**

The fact that CO emissions from units with varying NO_X controls did not behave as expected across different data sets does not directly lead to the conclusion that the use of a ratio of CO emissions to scale organic HAP emissions is inappropriate.

---

[546] This emission factor was provided by the CCCT vendor and is equivalent to the proposed BACT limit of 4.3 ppmvd at 15% O_2. TEC will be required to demonstrate compliance with the CO BACT limit through performance testing and continuous emissions monitoring.

[547] As described by USEPA in the preamble to the proposed Boiler MACT rule published June 4, 2010: "CO has generally been used as a surrogate for organic HAP because CO is a good indicator of incomplete combustion and organic HAP are products of incomplete combustion… For non-dioxin organic HAP, using CO as a surrogate is a reasonable approach because minimizing CO emissions will result in minimizing non-dioxin organic HAP. Methods used for the control of non-dioxin organic HAP emissions would be the same methods used to control CO emissions." 75 Fed. Reg. 32018 (June 4, 2010).

[548] AP-42, Chapter 3.1, Footnote d to Table 3.1-1.

Finally, CO and organic HAP emissions will increase at reduced operating loads and this was considered in calculating HAP emissions, particularly for startup and shutdown events. Organic HAP emissions were calculated using a lb HAP/lb CO emission factor derived from the organic HAP emission factors in AP-42 Table 3.1-3 and the uncontrolled CO emission factor in AP-42 Table 3.1-1 (0.082 lb/MMBtu) multiplied by the annual potential CO emissions from the turbines during startup and shutdown. The underlying principles behind this calculation are that: 1) both CO and organic HAP emissions are byproducts of incomplete combustion, and 2) any reduced combustion efficiency that occurs at the low turbine operating loads associated with startup and shutdown should equivalently affect the emission of CO and organic HAP. This theoretical concept is illustrated very well in Figures 3-2, 3-6, and 3-7 of the Gas Research Institute (GRI) and Electrical Power Research Institute (EPRI) study entitled *Gas-Fired Boiler and Turbine Air Toxics Summary Report* (Commenter's Exhibit 138).[549]

The GRI/EPRI study provides CO and organic HAP emissions data over a range of turbine operating loads for two utility turbines, a 73 MW Westinghouse 501AA turbine and a 150 MW GE Frame 7. Considering the low load CO and organic HAP emissions data from the GE Frame 7 turbine since it is closer in size to the turbines at the TEC, as shown in Figure 3-2, formaldehyde emissions 0.000015 lb/MMBtu at 100% load, 0.00005 lb/MMBtu at 70% load, 0.0002 at 50% load, and 0.0075 lb/MMBtu at 30% load. Notably, the formaldehyde emission factors at or above 60% load are all less than 0.00008 lb/MMBtu which is which is less than the emission factor used by CCG (0.0000814 lb/MMBtu).

These data also support that the calculation approach for formaldehyde emissions during startup and shutdown based on CO scaling is conservative. For example, the annual potential startup/shutdown emissions from the TEC's combustion turbines using the 30% load formaldehyde emission factor from the GRI/EPRI study (0.00750 lb/mmBtu-hr), conservatively assuming that the turbines operated at 30% load (2,250 mmBtu/hr x 30% = 675 mmBtu) throughout all of the startup/shutdown hours represented in the Application (232 hr/yr per turbine) would be 1.17 tpy versus 1.70 tpy presented in the application.[550]

An inspection of the CO and formaldehyde emissions curves in Figure 3-7 demonstrate that CO and formaldehyde emissions exhibit very similar behavior with respect to changes in turbine load such that a 1:1 formaldehyde-to-CO emissions ratio with load changes is an appropriate assumption for the TEC's HAP emission calculations. Furthermore, the plots of changes in benzene and toluene emissions with turbine load in Figure 3-7 show that benzene and toluene emissions do not increase as much as formaldehyde emissions as load decreases. The emissions calculations, however, assumed the same increase as assumed for formaldehyde for all HAP.

---

[549] Gas Research Institute ("GRI") and Electric Power Research Institute ("EPRI"), 1996. Gas-Fired Boiler and Turbine Air Toxics Summary Report. Prepared by Carnot Technical Services for GRI and EPRI, August 1996. Comment Exhibit 138.

[550] **0.0075 lb/mmBtu x 675 mmBtu/hr x 232 hr/yr/turbine x 2 turbines x 1 ton/2,000 lb = 1.17 tpy and 0.00866 lb formaldehyde/lb CO x 196.0 tpy CO during startup/shutdown = 1.70 tons/year.**

The use of the average formaldehyde emission factor from AP-42, Chapter 3.1 without scaling (0.00071 lb/mmBtu), is inappropriate for the proposed turbines. The emission factor was derived from 22 formaldehyde stack tests on natural gas-fired turbines ranging from 4 MW to 88 MW. The majority of these turbines are small, diffusion flame, aeroderivative turbines as opposed to the frame-type 207 MW lean premix turbines proposed for the TEC. EPA has stated that "lean premix combustors emit lower levels of NOx, CO, formaldehyde, and other HAP than diffusion flame combustion turbines."[551] Furthermore, the stack test results used to derive the emission factors are from the late 1980s and early 1990s.[552] Technology has improved significantly over the past 15-20 years, and emissions of organic HAPs have reduced along with CO emissions with the implementation of lean premix technology. Regardless of the formaldehyde emission calculation methodology, the issued permit has enforceable formaldehyde limits and provisions for testing formaldehyde emissions from the turbines in Condition 4.2.7, as formaldehyde is the only individual pollutant emitted from the power block with any likelihood of triggering HAP major source status. This testing will also confirm the appropriateness of the HAP emission calculation methodology.

Based on the clear differences in the types of turbines analyzed for AP-42 Chapter 3.1 and the turbines proposed at the TEC, CCG conducted a detailed evaluation of the AP-42 Chapter 3.1 formaldehyde emissions dataset provided on USEPA's website to determine if any discernable trends can be identified that would support the use of an emission factor lower than that provided in Table 3.1-3. The complete inventory of 52 facilities included in the dataset was first screened by combustion turbine fuel to exclude units that combust fuel oil, digester gas, or field gas. The 38 remaining facilities were than screened to remove test runs for turbine operating loads below 60 percent (i.e., the minimum steady-state operating load for the turbines at the TEC). Finally, the two facilities with CO/VOC control devices (one with CO catalyst and one with SCONOX) that are also expected to control formaldehyde emissions were removed from the similar facility inventory leaving 25 facilities for which average formaldehyde emission factors were analyzed. The analysis of the remaining sites in the inventory revealed that 6 facilities have measured three test run-average formaldehyde emission rates on both a lb/MWh and lb/MMBtu basis which exceed the maximum VOM emission rate for the turbines at the TEC. The formaldehyde emission data for these facilities is obviously not representative of the emissions profile for the turbines at the TEC, and therefore, they were excluded from the further analysis. The average formaldehyde emission factor for the remaining 19 facilities is 0.000199 lb/mmBtu which is a factor of nearly 4 lower than the Table 3.1-3 emission factor that includes emissions data from sites which are not representative of the TEC.

A similar analysis of the toluene emissions data in the USEPA AP-42 Chapter 3.1 database revealed 9 facilities with uncontrolled natural gas-fired combustion turbine data for toluene emissions testing conducted above 60 percent load. The same VOC emission rate screening technique applied for formaldehyde revealed that one facility

[551] Roy, Sims. U.S. Environmental Protection Agency, to Docket A-95-51, re: Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines, April 21, 2001.
[552] Based on AP-42 Section 3.1 underlying data. Available at http://www.epa.gov/ttnchie1/ap42/ch03/related/c03s01.html.

had a single stack test run which registered a very high toluene emission rate (290 ppb and 1.99E-03 lb/MMBtu) while the other two runs registered non-detectable results based on a detection limit of 20 ppb. This anomalous series of three test runs is clearly not representative of the toluene emissions expected from TEC's combustion turbines especially considering that the test runs were conducted on a General Electric LM 2500 aeroderivative turbine with a power output rating of only 24 MW. When this single erroneous test result is removed from the similar facility dataset, the average formaldehyde emission factor drops by more than a factor of 5 (i.e., from 0.000240 lb/mmBtu to 0.0000456 lb/mmBtu).

Although the formaldehyde and toluene emission factors based on this analysis are higher than the emission factors derived by CCG based on the CO scaling approach, the plant-wide annual potential HAP emissions using these factors and all of the other organic HAP emission factors in Table 3.1-3 directly without any adjustment based on removal of non-representative sources are still less than the major source threshold. In addition, these formaldehyde and toluene emission factors are based on emissions data from smaller, older, and higher emitting turbines, so they are expected to provide a conservatively high estimate of the emissions from the TEC's combustion turbines. Even considering this conservatism, the direct use of the appropriate formaldehyde and toluene emission data from the AP-42 Chapter 3.1 emissions database in lieu of the CO scaling approach still demonstrates the TEC is a minor source of HAPs. Furthermore, this analysis demonstrates that the use of the Table 3.1-3 formaldehyde and toluene emission factor to estimate HAP emissions from the TEC as the comment suggests would be entirely inappropriate since it includes emissions data for turbines that are not similar to or representative of the turbines at the TEC.

Based on the detailed analysis of the emissions data supporting the development of AP-42 Chapter 3.1, a review of data from various reference literature, and an evaluation of similar facility formaldehyde test data provided by CCG, the emission factors used for formaldehyde and toluene emissions are appropriate. [553]

108. The emission factors used by CCG for non-metallic HAPs underestimated emissions. Even if one accepted CCG's premise that SNG is equivalent to natural gas, the emission factors used by CCG to determine potential to emit for non-metallic HAPs (based on AP-42, Chapter 3.1) are not appropriate for estimating the "maximum capacity of a stationary source to emit any air pollutant" as required under 40 CFR 63.2 and 63.41.

First, almost all of the tests evaluated for AP-42, Chapter 3.1, were conducted for compliance purposes. Compliance tests, or source tests, are typically announced and, thus, give the operator the opportunity for optimizing equipment and operating at optimal conditions. As such, measured emission rates are most likely on the lower end of what would be observed under non-optimized conditions.

[553] See the following for Additional support for the formaldehyde and toluene emission factors: Comment Exhibit 138; EPA Combustion Turbine Emissions Database v.5. Available at http://www.epa.gov/ttn/atw/turbine/turbinepg.html**,** Chalfin, Joel and Richani, Brahim, GE Power Systems, *Support for Elimination of Oxidation Catalyst Requirements for GE PG7241FA DLN Combustion Turbines*, August 2001, available at http://site.ge-energy.com/prod_serv/products/tech_docs/en/downloads/ger4213.pdf, and Brooks, Frank, GE Power Systems, GE Gas Turbines Performance Characteristics, October 2000, available at http://143.107.98.150/Silvio/PME2517/GEgasTurbine.pdf.

Second, the *average* emission factors from AP-42 are not appropriate to determine the *maximum* HAP emissions from the facility. Either the *maximum* or the 95th percentile emission factors measured during those tests would have been more appropriate. (The USEPA provides Microsoft Access databases with all test results used to develop emission factors for Chapters 3.1 and 1.4[554]) In a memorandum on HAP emission factors from natural gas-fired turbines, the USEPA emphasizes that "[t]he 95th upper percentile emission factor may be more appropriate to use [than the average emission factor] for determining whether a source is major since it considers the test result variability."[555]

The EAB decision in *In re Peabody Western Coal Co.*, 12 E.A.D. 22, CAA Appeal No. 04-01 (Feb. 18, 2005) demonstrates why relying on emission factors is not sufficient in a potential to emit analysis. In that case, Peabody tried to establish that one of its facilities was a synthetic minor source for purposes of PSD. Peabody's request for a PTE limit of 185 ton/year relied on a quantitative estimate of the Facility's capacity to emit PM_{10}. This estimate, in turn, relied on emission factors and assumed emission control efficiencies. Peabody estimated the uncontrolled emissions from each emissions unit based on the application of AP-42 emission factors. Peabody then estimated the net emissions from these units by applying assumed control efficiencies, and requested that Region IX establish a PTE limit for the Facility based on the cumulative total estimated net emissions. Similarly, Peabody's proposed compliance regimen did not include direct measurement of PM emissions.

USEPA, Region IX, however, found a fundamental conceptual difference between PTE and actual emission performance that made Peabody's complete reliance on emission factors inappropriate in this instance. "While PTE is intended to identify the highest possible level of emissions that a facility is capable of releasing in light of its physical design and operational characteristics (considering enforceable restrictions on emission capacity), emission factors are intended to provide a generalized estimate of the average emissions performance of a particular type of emission source. According to AP-42, '[i]n most cases, these factors are simply averages of all available data of acceptable quality, and are generally assumed to be representative of long-term averages for all facilities in the source category (i.e., a population average).' As a result, according to Region IX, emission factors do not necessarily reflect the level of emission appropriate for calculating PTE." *In re Peabody Western Coal Co.*, 12 E.A.D. 22. Region IX stated that it "was not 'disputing Peabody's use of emission factors and control efficiencies for the purpose of calculating actual emissions,' but that because 'PTE is meant to be a worst case emissions calculation,' Peabody's approach was not adequate for 'the creation of a practically enforceable PTE limit for regulatory purposes." *Id.* The Environmental Appeals Board upheld the Region's decision that this could not be a synthetic minor source when its PTE were based on emission factors. *Id.* Similarly, CCG's reliance of emission factors in its potential to emit HAPs analysis is inadequate.

[554] USEPA, AP 42 Section 3.1 Stationary Gas Turbines, Related Information and AP 42 Section 1.4 Natural Gas Combustion, Related Information; http://www.epa.gov/ttn/chief/ap42/ch03/related/r03s01 zip and http://www.epa.gov/ttn/chief/ap42/ch01/related/r01 s04.zip.
[555] Roy Sims, USEPA to Docket A-95-51, re: Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines, April 21, 2001 (hereafter "USEPA April 2011 Memorandum"); http://www.deq.state.ms.us/mdeq.nsf/pdf/epd_EPAtmemorelatedtoHAPs/$File/EPAMemoHAPs.pdf?OpenElement.

As discussed above, the emission factors used to calculate the HAP PTE were reasonable.[556] Regardless, the issued permit contains enforceable conditions that limit the HAP PTE such that the source is not a major source of HAPs. Unlike in the *Peabody* case, where both the PTE calculations and the requested permit limits for fugitive PM emissions would have used the same emission factors for demonstrating compliance to ensure the minor source status, the issued permit requires actual testing to demonstrate compliance.

109. Emissions of hexane are not included in the emission data for HAPs. The Application does not estimate emissions for hexane for either normal operation or startup/shutdown arguing that "[s]ince hexane emissions were not detected during the combustion turbine testing used to develop the AP-42 Chapter 3.1 emission factors, hexane emissions are not expected from the CCCTs at the Taylorville facility."[557] This is a curious argument as the same logic holds true for all other pollutants for which the application used emission factors from AP-42, Chapter 1.4 for external natural gas combustion. CCG had no such compunction about using AP-42 Chapter 1.3 emission factors for the pollutants acenaphthene, acenaphthylene, anthracene, benzo(a)anthracene, benzo(a)pyrene, benzo(a)fluoranthene, benzo(g,h,i)perylene, benzo(k)fluoranthene, chrysene, dibenz(a,h)anthracene, 1,4-dichlorobenzene, 7,12-dimethylbenz(a)anthracene, fluoranthene, fluorene, indeno(1,2,3-cd)pyrene, 3-methylcholanthrene, methylnaphthalene, or pyrene for estimating emissions from the turbines.[558]

In fact, the only reason that CCG resorted to using Chapter 1.4 emission factors is because Chapter 3.2 for natural gas-fired turbines does not provide emission factors for those HAP pollutants. The only difference between the above-mentioned pollutants and hexane is the fact that Chapter 1.4 provides an emission factor for hexane that is between three and six orders of magnitude larger than the emission factors provided for the other pollutants. It is obvious that this exclusion argument was developed to avoid quantifying the large emissions that would result from applying the Chapter 1.4 emission factor for hexane (0.0018 lb/mmBtu[559]) as emissions from normal operation alone would amount to 16.9 ton/yr of hexane[560], thereby exceeding the single source HAP threshold for a major source. This example illustrates the arbitrary and baseless approach that the CCG used to estimate emissions for the TEC.

Relying on the external natural gas combustion hexane emission factor from AP-42 Chapter 1.4 to quantify emissions from the internal combustion processes occurring in CCG's turbines would not be appropriate. A review of available turbine emissions data in AP-42 Section 3.1 and USEPA's Combustion Turbine Emissions Database v.5 indicates that hexane emissions are not detected during combustion turbine testing.

---

[556] **The comment also suggests that CCG should be using either the maximum or the 95th percentile emission factors measured during the tests used to establish the emission factors in AP-42 Section 3.1 citing Roy, Sims. USEPA, to Docket A-95-51, re: Hazardous Air Pollutant (HAP) Emission Control Technology for New Stationary Combustion Turbines, April 21, 2001. This is a misreading of the memo, which does not refer to the AP-42 Section 3.1 emission factors. It is not customary to use the 95th percentile when determining the most likely emissions, particularly when calculating an annual average emission rate. Additionally, the use of the lean premix stationary combustion turbine data described in the memo to establish HAP emission factors is not appropriate for formaldehyde emission factor for the TEC given the inclusion of small, aeroderivative turbines in the derivation of the emission factor.**

[557] Ap., Appx. C, Footnote D to Table C-23, p. C-91.

[558] *See*, Ap., Appx. C, Table 23.2, pp. C-89 to C-91.

[559] (1. 8 lb hexane/million scf) / (1 million scf/1,020 mmBtu) = 0.00176 lb hexane/mmBtu.

[560] (0.00176 lb hexane/mmBtu) x (2,250 mmBtu/hour) x (8,528 hours/year) x (1 ton/2000 lb) x (2 turbines) = 16.93 tons/yr.

Therefore, hexane emissions from the turbines are negligible. Additionally, the hexane emission factor provided in AP-42 Section 1.4 (0.0018 lb/MMBtu) exceeds the VOM BACT limit for the turbines (0.0013 lb/mmBtu); since hexane is part of VOM, it is impossible for hexane emissions alone to exceed VOM emissions.[561,562]

The use Chapter 1.4 factors for selected organic HAPs was unrelated to the decision not to use the hexane emission factor from Chapter 1.4. The Chapter 1.4 emission factors for the non-hexane organic HAP compounds listed in the comment were used to quantify the trace levels of these compounds in the turbine exhaust which might occur even though explicit factors for these compounds are not included in AP-42 Chapter 3.1. Chapter 3.1 includes an emission factor for polycyclic aromatic hydrocarbons (PAH) as a class of pollutant, but does not speciate these compounds into individual HAP compounds. HAP compound speciation is required to accurately evaluate the HAP source classification of the TEC on an individual HAP compound basis. Thus, the speciated PAH emission factors from Chapter 1.4 were used instead of the scaled combined PAH factor from Chapter 3.1.

110. Emissions of hydrogen chloride (HCl) were omitted from the calculations. During the gasification process, most of the chlorine in coal is HCl, which is a HAP.[563] The actual concentration of HCl in the syngas stream will depend on the chlorine content of the coal, the gasification temperature, the type of gasifier, and the presence/concentration of alkali metals in the gasification system.[564] The Application provides estimates for HCl emissions from the flare and from equipment leak fugitives; however, it fails to estimate emissions of HCl from sources that combust SNG, including the CCCTs, the AGR vent catalytic oxidizer, the SRU thermal oxidizer, auxiliary boiler, coal milling and drying stack, or the methanation startup heater.[565] The permit record does not provide a satisfactory explanation why HCl emissions were not quantified for these sources.

The Project Summary, page 2, admits that the syngas exiting the gasifier contains significant amounts of HCl and claims that the pollutant is removed when the raw syngas is scrubbed with water. The Application provides that the syngas conditioning train removes

---

[561] **The Chapter 1.4 hexane emission factor is expected to significantly overpredict emissions from natural gas-fired combustion sources. It is based on two stack tests consisting of one test run for a 27.9 mmBtu/hr industrial boiler at Facility ID 115.7 and two test runs for a 2.2 mmBtu/hr boiler at Facility ID 120.1. The single USEPA Reference Method 18 run for Facility 115.7 reported exhaust concentrations of exactly 1.0 ppmv for butane, ethane, hexane, pentane, and propane. These speciated organic compound stack test results suggest that the concentrations were all set to the limit of detection for Method 18 (1 ppm) because these compounds were not detectable in the boiler's exhaust stream using the standard analytical methods required by Method 18. A non-detectable stack result cannot be used to confirm or deny the presence of a particular compound in an exhaust stream, and therefore, assuming emissions of the compound in question are equivalent to the detection limit is very conservative and results in artificially high estimates of emissions. The two test runs for the 2.2 mmBtu/hr boiler at facility 120.1 revealed results of 0.2 and 0.3 ppmv, respectively, for hexane. During these same test runs the non-methane hydrocarbon (NMHC) emissions from the boiler were reported as 1 ppm, which suggests that hexane emissions comprise between 20 and 30 percent of NMHC. This high fraction of hexane in the exhaust indicates that the combustion efficiency of the boiler was low during the test which is supported by the very high NOx concentrations measured during these test runs (140.2 and 143.6 ppmv, respectively). Since the combustion processes in the TEC's turbines will be managed carefully in accordance with good combustion practices to achieve compliance the stringent VOC BACT limit, the hexane stack test results from this very small boiler with poorly controlled burners is not representative of the organic HAP emissions that are expected to occur from the TEC turbines.**

[562] **Contrary to the comment, CCG did not rely on AP-42 Chapter 1.3 emission factors (see pg. 114).**

[563] Ola Maurstad, Massachusetts Institute of Technology, An Overview of Coal based Integrated Gasification Combined Cycle (IGCC) Technology, September 2005, MIT LFEE 2005-002 WP; http://seguestration.mit.edu/pdf/LFEE 2005-002 WP.pdf, (Commenter's Exhibit 139).

[564] *See, e.g.*, Krishnan G., SRI, and Gupta R., Research Triangle Institute, Development of Disposable Sorbents for Chloride Removal from High Temperature Coal-Derived Gases, Final Technical Report, September 1999, p. 1; http://www.fischer-tropsch.org/DOE/DOE reports/30005/30005-02/30005-02-fnal.pdf, (Commenter's Exhibit 140)

[565] Ap., Table C-23.1, pp. C-84 to C-87.

approximately 99% of the chlorides contained in raw syngas yet fails to account for the 1% of chlorides that would remain in the sweet syngas.[566] This remaining 1% of the chloride, if not otherwise removed, will be combusted with the cleaned sweet syngas and SNG and must therefore be accounted for in the HAP emission estimates.

The air permit application for the Kentucky NewGas SNG facility, which was prepared by Trinity Consultants (the same consultant that prepared the application for the TEC), established separate HCl emission factors for syngas and SNG combustion based on emission factors determined from a series of stack tests conducted at the Wabash River and Louisiana Gasification Technologies, Inc. ("LGTI") facilities.[567] The application provides no discussion why these emission factors were not deemed equally applicable to combustion of SNG at the TEC and instead zero emissions were assumed for combustion of these gases.

Based on the higher of the two SNG emission factors from the Kentucky NewGas application (from LGTI stack tests), emissions of HCl from the turbines during normal operations (no startup/shutdown) at the TEC can be estimated at 6.9 ton/yr.[568] When adding these HCl emissions to the application's estimate of 19.24 ton/yr of total facility-wide HAP emissions, the revised total facility-wide HAP emissions of 26.14 ton/yr exceed the major source threshold of 25 tons per year for total HAPs. Emissions of HCl during startup/shutdown and from other syngas and/or SNG-fired sources would further increase the facility-wide total. Thus, the TEC is a major source of HAPs.

Actual emissions of HCl from the TEC may be considerably higher than the above estimated 6.9 ton/year because of the substantially higher chlorine content in the Illinois Basin coal that would be gasified at the TEC compared to the subbituminous coal from the Rochelle mine in the Powder River Basin in Wyoming that was gasified at LGTI. The chlorine content of coal gasified at LGTI was measured at 0.0039 percent by weight (% wt).[569] The Application, Project Summary and Draft Permit are silent on the chlorine content of the coal that the TEC will gasify. However, a cost report developed for the ICC shows that the TEC would be designed to use of coal from the Illinois Herrin and Springfield seams with a maximum design chlorine content of 0.35% wt.[570] Review of the Illinois State Geological Survey ("ISGS") database for coal quality shows that the chlorine content in Herrin and Springfield coal seams is often considerably higher with up to 0.97 % wt and 0.74 % wt, respectively.[571] Thus, considering that the chlorine content in Illinois basin coal is almost two orders of magnitude higher than that of the Powder River Basin coal gasified at LGTI, one can reasonably expect that HCl emissions from the TEC will be correspondingly higher and will exceed the major source thresholds for both single and total HAPs.

---

[566] Application, p. 12.-i.
[567] Air Permit Application for New SNG Production Facility, Kentucky NewGas, Central City, KY, Volume 1 of 2, PSD/Title V Air Permit Application, Appendix C, Table C-22.3, p. C-78, and Table C-22.4, p. 79; http://vallevwatch.net/wp-content/uploads/docs/KY%20NewGas%20Volume%201%20Application.pdf, Commenter's Exhibit 141; Wabash River: syngas combustion emission factor = 0.0000048 lb HCl/mmBtu, SNG combustion emission factor = 0.000000993 lb HC1/mmBtu; LGTI: syngas combustion emission factor: 0.000785 lb HCl/mmBtu, SNG combustion emission factor = 0.000359 lb HCl/mmBtu.
[568] (0.000359 lb HCl/mmBtu)(2,250 mmBtu/hr/turbine)(2 turbines)(8,528 hr/year)(1 ton/2000 lb) = 6.89 ton HCl/year.
[569] Electric Power Research Institute and U.S. Department of Energy, Summary Report: Trace Substance Emissions from a Coal-Fired Gasification Plant, DCN 96-643-004-009, October 1999, p. 2-1 and Table 3-1, p. 3-4 (Commenter's Exhibit 115).
[570] Wood Mackenzie Study, p. 9.
[571] *Compare* Illinois State Geological Survey, Illinois Coal Quality Data; http://www.isgs.uiuc.edu/maps-datapub/coal-maps/strat-database/coal-qualitv-nonconf.xls.

The Draft Permit requires CCG to periodically test for the chlorine content of the coal (Conditions 4.1.7-2(c)(ii)(B) and 4.1.9(a)) and the raw syngas at the outlet of the gasifiers, sour syngas at the inlet to the AGR unit, sweet syngas at the outlet of the AGR Unit, and SNG at the outlet of the gasification block (Condition 4.1.9.b.). However, exceedance of the major source threshold by HCl emissions would not be detected because the permit would not lay out a procedure HCl for developing emission factors for based on these test results for the various emission units or require application of these emission factors in determining facility-wide HAP emissions. For example, the Draft Permit does not require source testing for HCl in turbine exhaust turbines and does not require that instead the chlorine content of SNG measured at the outlet of the gasifiers be used to develop an emission factor for HCl emissions from the turbines. Further, the Draft Permit does not require that unit-specific and facility-wide emissions be estimated and compared to the major source threshold(s) for single and total HAPs. The Draft Permit should be revised to include an unambiguous calculation procedure.

Due to the syngas cleanup processes in the gasification block, SNG should not contain quantifiable levels of HCl or any other chlorinated compounds. As the comment correctly points out based on Commenter's Exhibits 139 and 140, nearly all of the chlorine in coal is converted to HCl in the gasifiers. HCl gas is a very corrosive substance that must be removed very early in the syngas conditioning process to protect reactors, adsorbent beds, and absorbers in the downstream process units. In addition, HCl has a high affinity to dissolve in water, so at any location in the syngas processing train where water is removed, HCl will be removed as well. As discussed in Section 2.2.3 of Volume 1 to the Application, the primary purpose of the water scrubbers in the raw gas treatment process is to remove chlorides at an expected removal efficiency of 99%. Any chlorides that remain in the scrubbed, raw syngas would be routed to the shift unit and the low temperature gas cooling (LTGC) unit. The shift unit absorbent beds are expected to remove additional amounts of HCl present in the raw syngas. Water is condensed from the sour syngas in the LTGC unit, so additional HCl removal would occur in this unit as well. The AGR unit contains a wastewater purge stream which will contain HCl removed from the cooled, sour syngas. With multiple distinct removal steps for HCl prior to feeding sweet syngas to the methanation unit, it was appropriate for CCG to assume that the HCl concentration in the SNG is negligible.

The approach used by Kentucky NewGas to quantify HCl emissions from SNG-fired combustion equipment based on testing at the Wabash River and LGTI gasification facilities is not appropriate for use at the TEC. First, the only SNG-fired combustion equipment that will be present at the Kentucky NewGas facility is a 600 MMBtu/hr auxiliary boiler, a 40 MMBtu/hr startup heater, a 40 MMBtu/hr AGR vent oxidizer, a 25 MMBtu/hr ATS incinerator, and a 0.484 MMBtu/hr flare pilot for a total plant-wide heat input capacity of SNG-fired equipment of 705.5 MMBtu/hr.[572] In contrast, the combined heat input capacity of SNG-fired combustion equipment at the TEC will

[572] **Kentucky Division for Air Quality, *Final Air Quality Permit Issued Under 401 KAR 52:020 for Kentucky Syngas, LLC*, September 24, 2010, available at http://dep.gateway.ky.gov/eSearch/**

be 5,006 MMBtu/hr.[573] With a SNG heat input capacity of combustion equipment that is more than 7 times greater than the Kentucky NewGas facility, CCG had to apply a more refined and accurate approach for quantifying plant-wide HCl emissions than the approach used by Kentucky NewGas.

As shown in Section C-22 of Appendix C to the Kentucky NewGas application (Commenter's Exhibit 141), the LGTI HCl emission factor for SNG combustion used by the comment in the revised HCl emission calculations for the TEC is based on stack test data from the LGTI combustion turbines. The LGTI facility is no longer operating, but when it did operate the facility used subbituminous coal in a slurry-fed, entrained flow gasifier to produce unshifted syngas for combustion in an IGCC combustion turbine.[574] The only syngas processing train equipment used by LGTI was a wet scrubber and a Selectamine® AGR unit. The syngas processing train at the TEC is entirely different from the syngas processing train at the LGTI facility, and the modern state-of-the-art raw gas treatment, LTGC unit, and AGR units at the TEC will provide much higher levels of HCl removal than the much older and less efficient syngas processing train equipment at LGTI. The measured HCl concentration in the combustion turbine stack at LGTI was 420 µg/m^3 which equates to 0.27 ppmv.[575] The Wabash River HCl emission factor for SNG combustion is based on a product syngas HCl content of 0.01 ppmv. This was not a measured concentration, however, since HCl was not detected in the product syngas at the Wabash River site. Instead, the HCl concentration is based on one-half of the detection limit for the reference method used to analyze the product syngas. The wide disparity in HCl concentrations observed at the LGTI and Wabash River sites demonstrates that the HCl emissions from gasification plants are very site specific and must be estimated based on the specific configuration of the site under consideration.

Like the Wabash River plant, CCG fully expects that the HCl concentration in the raw syngas will be non-detectable and thus, the HCl emission factor from this site would provide a more representative emission estimate for the SNG-fired combustion equipment at the TEC. If the comment had used the Wabash River SNG combustion HCl emission factor (9.93E-07 lb HCl/MMBtu) in the Kentucky NewGas application (which is more than two orders of magnitude smaller than the LGTI emission factor of 3.59E-04 lb HCl/MMBtu), the annual potential HCl emissions quantified for the combustion turbines at the TEC would only have been 0.019 tpy. On a plant-wide basis, the HCl emissions calculated using this emission factor would only be 0.021 tpy.[576] [577] This worst-case estimate for HCl emissions from SNG combustion at the TEC is more accurate than the estimate provided by the comment based on the LGTI emission factor, and adding this HCl emission rate to the plant-wide total HAP

---

[573] 0.34 mmBtu/hr for flare pilots (Section C-3 to Appendix C of Volume 1 to the Application) + 7.1 mmBtu/hr for the SRU thermal oxidizer (Section C-4) + 26.5 mmBtu/hr for the AGR vent oxidizer (Section C-5) + 4,500 mmBtu/hr for the two combustion turbines combined (Section C-8) +148 mmBtu/hr for the two coal dryers combined (Section C-10) + 279 mmBtu/hr for the auxiliary boiler (Section C-14) + 45 mmBtu/hr for the startup heater (Section C-15) = 5,006 mmBtu/hr.

[574] Commenter's Exhibit 141, p. 3-19.

[575] Commenter's Exhibit 141, pg. 496 of 636. 420 ug HCl/m^3 x 1 g/1,000,000 ug x 1 lb/453.59 g x 1 m^3/35.31 scf x 379.5 scf/lbmol x 1 lbmol HCl /36.461 lb HCl = 0.27 ppmv.

[576] 0.000000993 lb HCl/mmBtu x 2,250 mmBtu/hr/turbine x 2 turbines x 8,528 hr/yr x 1 ton/2,000 lb = 0.019 tpy (which follows commenter's calculations on page 116, fn. 385 of its comments).

[577] 0.000000993 lb HCl/mmBtu x 5,006 mmBtu/hr x 8,760 hr/yr x 1 ton/2,000 lb = 0.021 tpy.

emission rate presented in Table 3-2 of Volume 1 of the Application would not change the HAP source classification of the facility (i.e., 19.24 tpy total HAP + 0.021 tpy HCl from SNG combustion = 19.26 tpy which is less than the 25 tpy total HAP major source threshold). Condition 4.1.9(b) requires CCG to conduct an initial SNG sampling program that includes an analysis for chlorine content. Based on this requirement in the permit, the presence of any measureable HCl in the SNG will be able to be determined. If measureable quantities of HCl in SNG are identified through the sampling required in the permit, Condition 4.2.10(d)(iii) would require CCG to keep monthly and annual records of the HCl emissions from the combustion turbines to demonstrate compliance with the plant-wide HAP limit in Condition 3.4.

111. Emissions of other HAPs were also omitted from the calculations. Similar to HCl, CCG did not account for emissions of a number of other HAPs including benzo(e)pyrene, carbon disulfide, dichloromethane (methylene chloride), hydrogen cyanide, perylene, and phenanthrene from sources that combust SNG including the turbines, the AGR vent catalytic oxidizer, the SRU thermal oxidizer, auxiliary boiler, coal milling and drying stack, or the methanation startup heater. Again, the permit record provides no discussion why the emission factors developed for the Kentucky NewGas SNG production facility were not deemed equally applicable to combustion of SNG at the TEC and instead zero emissions were assumed for combustion of these gases.

Benzo(e)pyrene, carbon disulfide, dichloromethane, hydrogen cyanide, perylene, and phenanthrene will not be present in measurable quantities in the SNG produced at the TEC, and therefore, any SNG combustion emissions of these compounds that may occur will be negligible. The choice by Kentucky NewGas to rely on syngas sampling and combustion turbine stack test data from the Wabash River and LGTI IGCC facilities to estimate annual HAP emissions of these compounds does not require CCG to rely on the same data for its estimation of HAP emissions from the TEC. As discussed previously, the Wabash River and LGTI HAP emission factors for syngas combustion are expected to significantly over predict emissions from SNG combustion at the TEC because of the additional syngas processing steps and SNG conversion in the methanation unit that will be conducted at the TEC. The shift unit, LTGC unit, carbon adsorption beds, Rectisol® AGR unit, and methanation unit guard beds will all provide organic and soluble inorganic HAP removal. This syngas processing equipment is not present at the Wabash River and LGTI sites, and therefore, CCG appropriately relied on other reference data to quantify organic and inorganic HAP emissions from SNG combustion at the TEC (refer to Section C-22 of Appendix C for the basis of the organic and inorganic SNG combustion emission factors used by CCG).

The benzo(e)pyrene SNG combustion emission factor presented in the Kentucky NewGas application is based on the LGTI combustion turbine stack test. CCG quantified emissions of benzo(a)pyrene from SNG HAP combustion emissions sources based on the natural gas combustion emission factor from Chapter 1.4 of AP-42 (refer to footnote 6 to Table C-22.1 of Appendix C to Volume 1 of the Application). Benzo(e)pyrene and benzo(a)pyrene are isomers of a chemical compound with the same molecular formula, so they should be emitted in very similar quantities from any combustion process. The plant-wide annual potential benzo(a)pyrene emissions from

the TEC are 3.31E-05 tpy, so the benzo(e)pyrene emissions from the facility are expected to be at or below this very low level. For the combustion turbines, CCG quantified polycyclic aromatic hydrocarbon (PAH) emissions based on the stationary gas turbine emission factor in AP-42 Chapter 3.3. CCG also quantified speciated PAH emissions from the combustion turbines based on the natural gas combustion emission factors in AP-42 Chapter 1.4 (refer to Table C-23.2 of Appendix C to Volume 1 of the Application). Summing total PAH emissions from AP-42 Chapter 3.3 and speciated PAH emissions from AP-42 Chapter 1.4 results in "double-counting" of any PAH compounds represented in both AP-42 sections. Therefore, the combustion turbine PAH emission calculations for the TEC are conservative and the plant-wide annual potential PAH emissions represented in the Application conservatively account for the very small amount benzo(e)pyrene emissions that could potentially occur at the TEC.

As discussed elsewhere the only sulfur compounds expected to be present in the syngas produced at the TEC are H_2S and COS. Despite the expectation that carbon disulfide (CS_2) and other sulfur compounds will not be present in the TEC's syngas, the LGTI combustion turbine stack test data was used to develop a syngas combustion CS_2 emission factor for the flare and AGR vent oxidizer (i.e., the only syngas-fired combustion sources at the TEC). CCG did not however convert the syngas combustion emission factor into a SNG combustion emission factor because any trace levels of CS_2 that are present in the sweet syngas would be removed in the sulfur guard beds located upstream of the methanation unit. The catalyst used in the methanation unit is intolerant to sulfur, so the total sulfur content of the sweet syngas fed to the methanation unit reactors is expected to be extremely low (i.e., in the low parts per billion range). If CS_2 is present at all, it is not expected to even register as a constituent of SNG in the total sulfur SNG sampling required by Condition 4.1.9(b).

As discussed elsewhere, the only chlorine compound expected to be present in the syngas produced at the TEC is HCl. Dichloromethane emissions from the flare and AGR vent oxidizer were, however, quantified based on the same LGTI combustion turbine stack test data referenced in the Kentucky NewGas application. CCG decided not to convert this syngas combustion emission factor into a SNG combustion emission factor because the AGR unit is expected to remove any organic HAP compounds that have not already been removed by the water scrubbers, shift unit, LTGC unit, or carbon adsorption beds.

Hydrogen cyanide (HCN) is an inorganic HAP with similar solubility properties to HCl, thus, any location in the syngas processing train that removes HCl is expected to remove HCN at a similar level of removal efficiency. Following the same rationale presented previously for HCl, the removal efficiency of HCN in the syngas processing train is expected to be so high that measurable quantities are not expected to be present in the SNG.

Finally, perylene and phenanthrene are considered PAHs, and any emissions of these compounds that may be emitted from SNG combustion in the turbines would be accounted for in the PAH emissions estimate included in the Application. Although the AP-42 Chapter 1.4 natural gas emissions factors used for all SNG combustion sources

other than the turbines do not include these specific PAH compounds, these compounds should be emitted at levels that are equal to or less than the emissions rates of the other PAHs which were quantified in the Application based on AP-42 Chapter 1.4 emission factors (i.e., in the range of 0.0000331 tpy for benzo(a)pyrene to 0.0114 tpy for naphthalene, refer to Table C-23.1 of Appendix C to Volume 1 of the Application).

Even assuming the above emission factors for these compounds were representative, the combined annual potential emissions from SNG combustion at the TEC would be 1.08 tpy.[578] When added to the plant-wide potential emissions for total HAPs presented in Table 3-2 of Volume 1 to the Application, the revised annual potential total HAP emissions would be 20.3 tpy, which is still less than the HAP major source threshold of 25 tpy for total HAPs.

112. Malfunction emissions were not accounted for in calculations for potential emissions. The periods when a facility starts up, shuts down, or malfunctions are among the most dangerous because facilities may release high levels of pollution. As a result, the Clean Air Act imposes strict emissions limitations on startup, shutdown, and malfunction periods. IEPA ignored such limits by not properly determining emissions during malfunction events, and thus failing to regulate the emissions through MACT standards.

Every industrial facility faces the possibility of an "upset" condition. At the TEC, this could, for example, include a malfunction of the gasifier technology. While it is impossible to know if and when problems will arise, emissions associated with malfunctions must nonetheless be included in the facility's potential emit. As discussed in detail above, "potential to emit" is the "maximum capacity of a stationary source to emit a pollutant under its physical and operational design." *See* IL ST CH 415 § 5/39.5; see also 40 CFR 63.2, 63.41. This is essential the worst case scenario of potential emissions, which includes emissions during unexpected malfunctions. Moreover, startup, shutdown and malfunction events are unquestionably regulated under the Clean Air Act. *See, e.g.*, 65 FR 70,792, 70,793 (Nov. 28, 2000) (USEPA rulemaking "reiterate [ing] that, under the Act, all excess emissions during startups, shut down, or malfunction episodes are violations of applicable emission limitations.")

Despite the legal requirements to calculate and regulate these emissions, the Draft Permit does not account for HAP emissions from malfunction events.

This comments asserts that the permit does not take into account the PTE of HAP emissions from malfunction events. The IEPA disagrees, since malfunction events are not considered "normal" operations and thus emissions occurring during malfunctions need not be addressed in a source's PTE. PTE generally must be determined based on the "physical or operational design" of a source. In *Alabama Power Company v. Costle,* 636 F.2d 323 (D.C. Cir. 1979), the United States Court of Appeals for the D.C. Circuit explicitly rejected the notion that uncontrolled emissions, such as those stemming from unplanned malfunction events, are incorporated into the requirements of PTE.

[578] **On a combined basis, the combustion emission factors for these compounds from Wabash River SNG presented in the Kentucky NewGas application is 0.00000725 lb/mmBtu, and the LGTI emission factor is 0.0000495 lb/mmBtu. Therefore, the annual potential emissions of these compounds for the TEC can be calculated as follows: 0.0000495 lb/mmBtu x 5,006 mmBtu/hr x 8,760 hr/yr x 1 ton/2,000 lb = 1.08 tpy.**

Despite USEPA's argument in the case that PTE should address both controlled and uncontrolled emissions, the Court held that PTE is not based on potential emissions resulting from control equipment that fails to function properly. *See, Alabama Power*, 636 F.2d at 353. The Court held:

> **When determining a facility's potential to emit air pollutants, EPA must look to the facility's 'design capacity' -- a concept which not only includes a facility's maximum productive capacity (a criterion employed by EPA) but also takes into account the anticipated functioning of the air pollution control equipment designed into the facility.**

Id. **A subsequent court ruling favored this interpretation, recognizing that *Alabama Power's* holding construes PTE as not referring "to the maximum emissions that can be generated by a source hypothesizing the worst conceivable operation" but, instead, takes into account only those maximum emissions "generated while operating the source as it is intended to be operated and as it is normally operated." *See, Louisiana-Pacific Corp*., 682 F. Supp 1141, 1158 (D. Colo. 1988). These rulings indicate that PTE must be based on source operation as it is intended to operate normally, not unplanned events like malfunctions.**

Further, to conclude that emissions from malfunction events should be addressed in a PTE calculation is hardly needed where the permit includes practically enforceable limits restricting emissions. The EAB has held that whenever a permit effectively constrains malfunction emissions through enforceable permit limits, the issue as to whether malfunction events constitute "normal operations" for purposes of a PTE calculation is irrelevant. *See, In re Knauf Fiber Glass GMBH*, 8 E.A.D. 121, 159 (EAB 1999) (denying review of petition seeking estimates of malfunction emissions where the permit included emissions limits that applied during such periods).

THE DRAFT PERMIT WOULD NOT TO ESTABLISH FEDERALLY AND PRACTICALLY ENFORCEABLE LIMITATIONS CONSTRAINING POTENTIAL EMISSIONS OF HAPS TO BELOW MAJOR SOURCE THRESHOLDS

113. As detailed above, the TEC is not a genuine minor source of HAPs as it will easily exceed the significance thresholds for a number of pollutants. As discussed above, a "synthetic minor" source of HAPs is one with potential emissions in excess of major source emission thresholds except that enforceable limitations (practically enforceable) on the source's potential to emit are imposed to keep the source from emitting at or above major source emission thresholds. Therefore, IEPA could only find the TEC is a minor source if the permit establishes practically enforceable limitations that prevent it from exceeding those significance thresholds. The draft Permit does not meet that standard, so IEPA cannot deem this facility a synthetic minor source.

In order for IEPA to find that this facility is a synthetic minor source, the agency would have to quantify the facility's true potential to emit (worst case scenario) of methanol,

nonmetallic HAPs, hexane, and hydrogen chloride and then issue a permit that includes enforceable limitations on those pollutants. The Draft Permit does not currently do that.

Draft Permit Condition 3.4(b) establishes only facility-wide emission limits for lead and mercury at 0.22 and 0.10 ton/year, respectively. Condition 4.1.9.of the Draft Permit would require analysis of the metals content: a) in conjunction with emissions testing of the AGR unit and SRU; b) within 90 days of acceptance of a feedstock from a new source; c) within 90 days of a written request from IEPA; and d) at least once every two calendar years. The Draft Permit would further require that the Permittee keep a file containing the emission factors that the Permittee uses to calculate emissions of methanol, mercury, hydrogen chloride, hydrogen fluoride and other HAPs from the flare, the AGU, and the SRU with supporting documentation as well as records for total monthly and annual total HAP emissions from the flare, the AGU, and the SRU.[579] However, nowhere does the Draft Permit set out the formula for the emission respective calculations, or require that CCG demonstrate that monthly or annual total HAP emissions do not exceed the permit limits. Thus, the emission limits for HAPs are not enforceable. Therefore, IEPA cannot find that the TEC is a synthetic minor facility.

The issued permit contains practically enforceable HAP emission limits supporting that the TEC is not a major source of HAPs. Condition 3.4(a) establishes a plant-wide individual HAP limit of 10 tpy and a combined HAP limit of 25 tpy so that the TEC is not subject to the provisions of the 40 CFR Part 63 applicable to major sources of HAPs. In conjunction with the comprehensive testing, monitoring, recordkeeping, and reporting requirements in the permit, these enforceable plant-wide emission limits will ensure that CCG demonstrates its area source status. In addition to the plant-wide HAP limits in Condition 3.4(a), the permit also contains limits for certain individual HAPs:

- **Plant-wide lead and mercury emissions, 0.02 tpy and 0.01 tpy, respectively [Condition 3.4(b)][580]**
- **Methanol and COS emissions from the AGR vent oxidizer, 2.68 tpy and 1.65 tpy, respectively [Condition 4.1.6(a)]**
- **COS emissions from the flare, 0.90 tpy [Condition 4.1.6(b)]**
- **Formaldehyde emissions from the combustion turbines, 4.96 tpy [Condition 4.2.6(a) and Attachment 1 Table I]**
- **Hexane emissions from the coal dryers, 1.14 tpy [Condition 4.3.6(d)]**
- **Hexane emissions from the auxiliary boiler, 1.08 tpy [Condition 4.5.6]**
- **Methanol emissions from the methanol tank, 0.21 tpy [Condition 4.8.6][581]**
- **COS and methanol emissions from equipment leaks, 1.00 tpy and 1.05 tpy, respectively [Condition 4.9.5]**

[579] Draft Permit, Conditions 4.1-10-2(b)(i) and (b)(iv), 4.1.10-3(a)(i) and (a)(iv) and Condition 4.1.10-4(f)(i) and (f)(iv).

[580] **The Draft Permit would have set plant-wide emission limits for lead and mercury of 0.22 tpy and 0.10 tpy, respectively. However, CCG submitted a revised set of trace metals emission calculations during the public comment period to reflect the 90% removal efficiency for all trace metals that is expected to be provided by the syngas conditioning train, requesting a reduction in the lead and mercury limits to 0.02 tpy and 0.01 tpy, respectively (refer to November 8, 2011 letter from Mr. Larry Carlson, CCG to Mr. Dean Studer, IEPA). (refer to December 28, 2011 letter from Mr. Larry Carlson, CCG to Mr. Dean Studer, IEPA).**

[581] **In the issued permit, the emission limit for methanol for the methanol tank has been set at 0.25 tpy, from 0.21 tpy, as discussed previously.**

Limits are imposed on formaldehyde, methanol, COS, and hexane because these are the four highest emitted HAPs at the facility comprising more than 83% of the plant-wide total HAP emissions.[582]

The permit does require CCG to demonstrate that monthly and annual HAP emissions do not exceed the limits in the permit through testing, monitoring, recordkeeping, and reporting requirements associated with each of the HAP limits.

- ***Plant-wide Lead Limit in Condition 3.4(b)*: Requires CCG to use data from the raw syngas, sour syngas, sweet syngas, and SNG sampling required by Condition 4.1.9(b) to develop lead emission factors for combustion of each of these process gases. CCG is also required to conduct lead sampling for coal [Condition 4.1.9(a)]. For all lead emission sources other than the limited-use fire pump and emergency generator engines, CCG also is required to compile the actual emission factors derived from the sampling results and to record the monthly and 12-month rolling actual lead emissions calculated based on these emission factors [Conditions 3.4(d) and 3.7(e) for the general recordkeeping requirements for HAP emissions, Condition 4.1.10-2(b) for the flare, Condition 4.1.10-3(a) for the AGR unit, Condition 4.1.10-4(f) for the SRU, Condition 4.2.10(d) for the combustion turbines, Condition 4.3.10(f) for the coal dryers, Condition 4.5.9(g) for the auxiliary boiler, and Condition 4.6.8 for the startup heater].**
- ***Plant-wide Mercury Limit in Condition 3.4(b):* Requires CCG to demonstrate compliance with the plant-wide mercury limit on a monthly basis based on data from the same coal and process gas sampling programs used to demonstrate compliance with the lead limit.**
- ***AGR Vent Oxidizer Methanol Limit in Condition 4.1.6(a)*: CCG is required to conduct an initial performance test for methanol emissions from the AGR vent oxidizer (Condition 4.1.7-2). The results of this performance test will be converted into an emission factor for use with AGR unit operating data collected under Condition 4.1.8-3(b) to quantify actual emissions on a monthly and 12-month rolling basis in accordance with Condition 4.1.10-3(a).**
- ***AGR Vent Oxidizer COS Limit in Condition 4.1.6(a)*: Condition 4.1.9(c) requires CCG to sample and analyze the AGR vent upstream of the oxidizer for its COS content in conjunction with the initial performance test for oxidizer. This COS sampling data will be used in conjunction with data for the combustion efficiency achieved in the oxidizer during the performance test to determine the COS emission rate from the oxidizer. Similar to the approach to the methanol emission limit, this COS emission rate derived from the performance test will be converted into an emission factor and used with AGR unit operating data to calculate actual emissions on a monthly and 12-month rolling basis.**

[582] **The formaldehyde emission limit for the combustion turbines (4.96 tpy) comprises more than 97% of plant-wide annual potential formaldehyde emissions (5.07 tpy, refer to Table C-23.1 of Appendix C to the Application). The sum of the methanol emission limits for the AGR vent oxidizer, methanol tank, and equipment leak components (3.94 tpy) comprise more than 93% of the plant-wide annual potential methanol emissions (4.23 tpy).[582] The sum of the COS emission limits for the AGR vent oxidizer, flare, and equipment leaks (3.55 tpy) comprises more than 86% of the plant-wide annual potential COS emissions (4.11 tpy, refer to Table C-23.1). Finally, the sum of the hexane emissions from the coal dryers and auxiliary boiler (2.22 tpy) comprise more than 93% of the plant-wide annual potential hexane emissions. Based on these statistics, the vast majority of the HAP emissions expected to be emitted by the TEC are subject to enforceable emission limits beyond the plant-wide limits in Conditions 3.4.**

- ***Combustion Turbine Formaldehyde Limit in Condition 4.2.6(a):*** **CCG is required to conduct an initial performance test for formaldehyde emissions from the combustion turbines [Condition 4.2.7(a)(i)(A)]. The measured formaldehyde emission rate during the performance test will be converted into an emission factor (in units of lb/million scf or lb/mmBtu) and used in conjunction with fuel usage or heat input data (Condition 4.2.9-2) to calculate actual emissions in accordance with Condition 4.2.10(d).**
- ***Coal Dryer Hexane Emission Limit in Condition 4.3.6(d):*** **Condition 4.3.7-1(d) requires CCG to conduct an initial performance test for hexane emissions from the coal dryers. The measured hexane emissions during the performance test will be converted into an emission factor and used in conjunction with fuel usage records [Condition 4.3.10(f)(ii)] to calculate actual emissions in accordance with Condition 4.3.10(f)(vi).**
- ***Auxiliary Boiler Hexane Emission Limit in Condition 4.5.6:*** **Similar to the coal dryers, CCG is required to conduct an initial performance test for hexane emissions from the auxiliary boiler [Condition 4.5.7(a)(ii)] and to use this data in conjunction with fuel usage records [Condition 4.5.9(d)] to calculate actual hexane emissions [Condition 4.5.9(g)].**
- ***Methanol Tank Methanol Emission Limit in Condition 4.*8.6: Condition 4.8.6 requires CCG to demonstrate compliance with the methanol emission limit for this tank using the methodology in USEPA's Compilation of Air Pollutant Emissions Factors, AP-42, the latest version of the TANKS program, or other methodology published by USEPA, including emissions due to roof landings, with emission calculations required to be performed in accordance with Condition 4.8.8(e).**
- ***Equipment Leak Component COS Emission Limit in Condition 4.9.5:*** **As discussed elsewhere for components included in the LDAR program, actual COS emissions will be calculated based on the results of periodic LDAR monitoring and stream composition data from the final, as-built heat and material balances for the TEC. For components that are not covered under the LDAR program, actual COS emissions will be calculated based on the SOCMI without ethylene emission factors and stream compositions from the final heat and material balances. Emission calculations based on these methodologies are required to be conducted in accordance with Condition 4.9.7(c).**
- ***Equipment Leak Component Methanol Emission Limit in Condition 4.9.5:*** **Actual methanol emissions from equipment leaks will be calculated based on the same methodology used for COS emissions.**

For the plant-wide HAP emissions which are not explicitly addressed in individual permit limits, CCG is still required to use the best available data to quantify actual HAP emissions on a monthly and 12-month rolling basis. The results of the trace metals sampling for coal and process gas required by Condition 4.1.9(a) and (b) could be used to quantify metallic HAP, chloride compound (i.e., HCl), fluoride compound (i.e., hydrogen fluoride), and sulfur compound (i.e. COS and any other trace HAP sulfur compounds) emissions from syngas and SNG combustion sources. The results of VOM testing could be used in conjunction with speciation data from AP-42 to quantify organic HAP emissions from SNG-combustion sources. Finally, reference emission factors either from the same basis used in the Application or from more recent and

accurate references could be used to quantify emissions of any HAP compounds that are expected to be emitted at the TEC but for which no site-specific data is available.

The issued permit does not set out a prescriptive formula for how CCG must demonstrate compliance with the HAP limits in the permit because such a formula would have to be continually updated to reflect the most recent and most accurate data. Relevant data from performance tests, periodic sampling, parametric monitoring systems, and reference literature that is required to calculate actual HAP emissions on an on-going basis is not static information that should be included in a preconstruction permit.

VII. APPLICABLE EMISSION STANDARDS

NEW SOURCE PERFORMANCE STANDARDS FOR ELECTRIC UTILITY UNITS

114. The TEC is an integrated "Coal-fired Electric Utility Steam Generating Unit"

The Draft Construction Permit-PSD Approval ("Draft Permit") and accompanying Project Summary describe the TEC as a plant that would use coal gasification technology to produce substitute natural gas ("SNG") for sale or use on-site to generate electricity. However, the application and other materials reveal that the TEC is, just as its name implies, an integrated facility for energy production – a coal-fired electric utility steam generating unit.[583] As presented to the Illinois Commerce Commission (ICC) in a review of the TEC Facility Cost Report, "the primary purpose of [TEC] is to produce clean coal electricity for Illinois, not to produce [SNG] for the pipeline or operate fully on pipeline natural gas." (ICC, Analysis of the Taylorville Energy Center Facility Cost Report, Attachment A (Review of TEC's Facility Cost Report) at 360 (Sept. 1, 2010)) ("ICC Report"). Attempts by CCG and IEPA to redefine the source as something other than an EGU are based on significant errors of law and fact.

First, the TEC, which will gasify coal and use the SNG and sometimes also pipeline natural gas to generate electricity, clearly has as its primary purpose electricity generation. ICC Report at 9, 11; *id.* Attachment A at 8, 360; *id.* Attachment C (ICC Press Release); *see also*

[583] CCG's PSD/Construction permit application refers to the project as a "fossil fuel-fired steam electric plant[] of more than 250 million (mmBtu/hr)" heat input. Updated Prevention of Significant Deterioration and State Construction Permit Application ("Application"), Vol. 1 page 4-1 (October 2010). Additionally, CCG's September 2011 Safe Drinking Water Act Underground Injection Control Program Class VI well permit application describes the TEC project multiple times as an "electric generating facility," using "advanced Integrated Gasification Combined-Cycle technology". Taylorville Energy Center Underground Injection Control Permit Request – Class VI Permit Application, at 3, 4, 85, Testing and Monitoring Plan at 1 (Sept. 20, 2011) ("UIC Permit Request") (attached as Appendix A). An August 2011 Fact Sheet about the TEC, available on the project's website, asserts that "[TEC] will generate electricity using [IGCC] technology with [CCS] …." TEC: Fact Sheet (Aug. 2011) available at: http://www.cleancoalillinois.com/pdfs/Taylorville_Fact_Sheet1.pdf.
Others also describe the TEC as an electric generating unit. One of the project's investors describes the facility as "an integrated gasification combined-cycle (IGCC) project," http://www.tenaska.com/page.aspx?id=15&pid=8; and the Illinois Commerce Commission's September 2010 Analysis of the Taylorville Energy Center, pursuant to section 1-75(d)(4)(ii) of the Illinois Power Agency Act, describes TEC as "a proposed electric power plant…that…will purchase a substantial amount of pipeline natural gas to supplement its SNG when it wants to produce maximum electricity output." ICC Report at 9 (citing and quoting the ICC's consultant, Boston Pacific Company, Inc. and MPR Associates ("BP/MPR") Evaluation of the project, at 1). The ICC further recognizes that "the TEC can be viewed as two separate functioning [electricity] generating plants: one that operates on coal-derived synthetic natural gas, and another that operates on pipeline-delivered natural gas unrelated to the use of coal." ICC Report at 11.

IEPA, Air Permit Control-Permit Record for Christian County Generation, LLC available at: http://yosemite.epa.gov/r5/in_permt.nsf/93a421690cb50df18625762300769ee3/72edc5201496bac58625797a004ed785!OpenDocument (describing the facility as an IGCC power plant). Although CCG and IEPA assert that the gasifier is distinct from the turbine, so as to permit them to be subject to different new source performance standards ("NSPS") requirements than those to which an EGU/IGCC plant is subject, in fact the plant taken as a whole (gasifier through turbine) meets the regulatory definition of an integrated electricity generating facility in the NSPS Da regulations. TEC is an "electric utility steam generating unit" under 40 CFR 60.41Da, as it will be "constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale." 40 CFR 60.41Da (definitions), *see also* Application, Vol. 1 at 1-2 (describing the facility's electric output potential and expected functioning). TEC is a "coal fired electric utility steam generating unit" under the same section of the rules, because it "burns … a synthetic gas derived from coal either exclusively …or in any combination with other fuels in any amount." Additionally, TEC is an "integrated gasification combined cycle (IGCC) electric utility steam generating unit" because it is an electric utility combined cycle gas turbine designed to burn fuels containing 50 percent (by heat input) or more solid-derived fuel not meeting the definition of natural gas," where "solid-derived fuel" includes "gasified coal." *Id.*

The SNG-fired turbines at the TEC, moreover do not satisfy the prerequisites for exception from Subpart Da requirements available for "heat recovery steam generators used with duct burners" that meet the applicability requirements of Subpart KKKK, as this is available only for turbines that are *not* at an IGCC facility (TEC is an IGCC, as shown above), and that use duct burners (TEC does not). *See* 40 CFR 60.40(e); *see generally*, Application (describing the plant). Nor do the applicability provisions of Subpart KKKK fit the TEC burner, in any event, as the KKKK provisions specifically exempt "[s]tationary combustion turbines at [IGCC] electric utility steam generating units that are subject to Subpart Da." 40 CFR 60.4314(c).

Indeed, little is different in terms of the broad concept (or even basic facility design) from that permitted in 2007 for an IGCC facility. *See In re Christian County Generation LLC*, 13 E.A.D. 449, 451 (2008) (describing the plant permitted in 2007 as a facility that would convert Illinois Basin coal into synthetic gas and then burn it in a separate turbine to generate electricity). The main difference is the introduction of a methanation process by which any excess SNG *could* be sold rather than burned at the combustion turbine to generate electricity. But this is an artificial difference, and indeed one that is unlikely to be necessary – as, according to the ICC Report, the TEC "would normally operate" with both gasifiers available, all turbines operating and available, and no SNG sales to the market – in this "normal" mode, TEC would need to purchase natural gas from the market in order to sustain the nameplate capacity required of an "initial clean coal facility" under Illinois law. ICC Report at 11 & Table 2. The project's website confirms that "power from the [TEC] is intended to be generated 24/7." *See* http://www.cleancoalillinois.com/index.html. Therefore, if the TEC can be considered as two separate plants, it is as "two separate functional [electric] generating plants: one that operates on coal-derived [SNG], and another that operates on pipeline-delivered natural gas unrelated to the use of coal." ICC Report at 11.

Importantly, as noted above, for the TEC, CCG is seeking status of as an "initial clean coal facility" under Illinois law. ICC Report at 1 n.1 (citing 20 ILCS §3855, Public Law 95-1027); Public Hearing Transcript at 13. This law offers the benefits of this status, including financial benefits and secure markets for the electricity produced by the facility, only to an "electric generating facility that uses primarily coal as a feedstock and that captures and sequesters carbon emissions at the following levels: at least 50% of the total carbon emissions that the facility would otherwise emit if, at the time construction commences, the facility is scheduled to commence operation before 2016…." 20 ILCS 3855 §§1-10, 1-75(d). The Project Summary is very confused on this point – while IEPA asserts that TEC "is currently not subject to the Clean Coal Portfolio Standard Law," (Project Summary. p 6), it also asserts that "Christian County Generation is still developing the project to satisfy [the Illinois] law's requirements," *Id., and see* 22 (Christian County seeks to develop a plant that would qualify as a Clean Coal Facility). And again, this is supported by current information on the project website, *see* http://www.cleancoalillinois.com/index.html, and provided at the December 1, 2011 public hearing. Public Hearing Transcript at 14 lines 7-12.

TEC's clear primary purpose is the generation of electricity. In so far as the sale of substitute natural gas (SNG) is an element of this project and not of the previous configuration, furthermore, it is a cost-related design element that is not sufficient justification for treating the plant as anything other than an electric generating facility. *See In re Prairie State Generating Company*, 13 E.A.D. 1, 23 n.23 (EAB 2006) (cost savings generally are not a sufficient purpose or objective that would justify treating a design element as basic or fundamental). While the IEPA cannot ask CCG to change the fundamental scope of its project, reviewing the TEC as an electric generating facility subject to Subpart Da requires no such change in what is proposed. Indeed, it is the attempt to call TEC something other than an EGU that "redefines the source" in unlawful ways, as it is undertaken seemingly in order to avoid the requirements of Subpart Da at this plant. *Cf. Sierra Club v. EPA*, 499 F.3d 653, 654 (remarking that it would be impermissible for the applicant to design a source in a way calculated to make measures for limiting the emission of pollutants ineffectual). As an EGU, TEC is subject to the Subpart Da conventional air pollutant emissions proposed in May, 76 FR 24,976 (May 3, 2011), and finalized December 16, 2011, as well as the expected subpart Da greenhouse gas limits which were due out September 30, 2011 under the terms of a consent decree between USEPA and various state and environmental plaintiffs. *See AEP v. Connecticut*, 564 U.S. --, 131 S. Ct. 2527, Slip Op. at 3 & 11 (2011) (noting that final NSPS for electricity generating facilities is due by May 2012 under the terms of the agreement).

For all of these reasons, IEPA's acceptance of CCG's attempt to have emissions limits for the gasification block set separately from the power block, as reflected in the Draft Permit, rather than setting BACT emissions limits for the plant as a whole, and based on Subpart Da NSPS as the "floor" for the BACT emissions limit, is based on a clear error of law (and fact). The limits in any permit issued to the plant reflect the fact that the TEC is an electric generating facility subject to 40 CFR 63 Subpart Da.

This NSPS does not apply in the way suggested by this comment. Moreover, even if it did, it would not achieve the underlying result that is sought. By way of further explanation, stationary combustion turbines are generally subject to the NSPS, either

40 CFR 60 Subparts GG or KKKK. 40 CFR Subpart Da applies narrowly to two specific types of electric utility combined cycle turbines. These include (i) IGCC units constructed after February 28, 2005 capable of combusting more than 73 megawatts (MW) (250 mmBtu/hr) heat input of fossil fuel (*see* 40 CFR 60.40Da(b)(1)-(2)), and (ii) duct burners contained within heat recovery steam generators (HRSGs) associated with non-IGCC electric utility combined cycle gas turbines not subject to Subpart KKKK (*see* 40 CFR 60.40Da(e)(1)). CCG does not propose to employ either of these specific combined cycle turbine designs at the TEC. Accordingly, 40 CFR 60 Subpart Da is not applicable in this instance.

In particular, each of the combustion turbines at the TEC will not be an "integrated gasification combined cycle electric utility steam generating unit" (or "IGCC" unit) as defined by 40 CFR 60.41Da. An IGCC unit is defined for the purposes of this Subpart as "an electric utility combined cycle gas turbine that is designed to burn fuels containing 50 percent (by heat input) or more *solid-derived fuel not meeting the definition of natural gas.*" 40 CFR 60.41 Da (emphasis added) [77 FR 9304, 9449 (Feb. 16, 2012)]. "Natural gas" is defined in this context as follows. The TEC will be developed to produce SNG that meets the specifications in this definition as it would be developed to produce SNG for commercial sale.

> **…a fluid mixture of hydrocarbons (e.g., methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet." Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal derived gas, producer gas, coke oven gas, or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value. *Id.***

This comment does not demonstrate that the Draft Permit would improperly classify the plant. The issue for the regulatory classification of the plant, as is addressed by this comment, is not CCG's purpose or intent for the plant but the physical configuration of the plant and its equipment. In this regard, the key fact is that the combustion turbines at the TEC would not fire syngas but natural gas. This natural gas would be SNG produced in the gasification block and, as acknowledged by this comment, commercial natural gas provided to the plant by pipeline. The fact that the SNG would be produced by gasification of coal at the plant does not alter the fact that the combustion turbines would fire natural gas.

While the recent revisions to Subpart Da accompanying the Final EGU MATS Rule specifically exclude certain gaseous fuels, including "coal-derived gas," from the definition of "natural gas," this change does *not* alter the status of the combustion turbines at the TEC as non-regulated, *non*-IGCC units under Subpart Da. The exclusion of "coal-derived gas" is not a categorical exclusion of SNG from the definition of "natural gas" in Subpart Da. On the contrary, the revised Subpart Da

expressly recognizes that at least some gasified coal fuels -- those that, like SNG, exhibit all the requisite chemical and physical properties of natural gas -- can still be considered "natural gas" for purpose of Subpart Da. This is evident when the exclusion is properly considered not in isolation, but within the context of Subpart Da as a whole. The definition of "coal" in 40 CFR 60.41Da is particularly relevant since USEPA does not define "coal-derived gas.". Thus it is necessary to look to the definition of "coal" in 40 CFR 60.41Da to ascertain the scope of the exclusion of coal-derived gas from the definition of natural gas. "Coal" is defined as:

> **. . . [a]ll solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials in ASTM D388 (incorporated by reference, see §60.17) and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat, including but not limited to solvent-refined coal, gasified coal (not meeting the definition of natural gas), coal-oil mixtures, and coal-water mixtures are included in this definition for the purposes of this subpart. *See* 40 CFR 60.41Da (emphasis added).**

So, although the definition of natural gas excludes "coal-derived gas," the revised Subpart Da also retains a clear recognition that certain fuels produced from gasification of coal *will* meet the definition of natural gas. The maintenance of this explicit acknowledgement in the revised Subpart Da precludes a reading of "coal-derived gas" that would roundly disqualify all coal derived fuels as "natural gas." Such a reading would render the portion of the regulatory definition of "coal" emphasized above meaningless. Taken together, these Subpart Da definitions lead to the conclusion that the SNG produced by the TEC would appropriately be considered "natural gas." As such, the TEC is not an IGCC facility subject to Subpart Da.[584] Rather, Subpart KKKK and not Subpart Da, is applicable to the combustion turbines.

The fact that the plant previously permitted in 2007 was an IGCC facility is irrelevant. The comment incorrectly asserts that little has changed in terms of the plant's concept or design from that proposed in 2007. This may be due to a lack of understanding on the significance of the addition of a methanation unit to the plant. The earlier 2007 plant was designed to fire synthesis gas, or syngas, *not* meeting the definition of natural gas in Subpart Da. By contrast, the current plant would include a methanation unit for production of *SNG* which, as explained above, *does* meet the Subpart Da definition of natural gas and would be able to be sold and used commercially. The presence of a methanation unit is far from an "artificial difference." Moreover, it directly results in the TEC not being subject to 40 CFR 60 Subpart Da.[585]

---

[584] **In this regard, the combustion turbines at the TEC also will not have duct burners. As discussed, other than IGCC units, Subpart Da applies only to duct burners contained within the HRSGs associated with combined cycle turbines and not meeting the applicability requirements of Subpart KKKK. *See* 40 CFR 60.40Da(e)(1). The HRSGs proposed for Taylorville will *not* incorporate duct burners and, thus, are likewise excluded from applicability under part (e)(1) of Subpart Da. *See* Application at 7-6 through 7-7 (comparing TEC's combustion turbines to "similar CCTs without duct burners"). Regardless, even if TEC's HRSGs were expected to include duct burners, the duct burners would nevertheless still be excluded from Subpart Da per 60.40Da(e)(1) since they would fall squarely within the applicability provisions of Subpart KKKK. (The Subpart KKKK standards apply to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 mmBtu) per hour which commenced construction, modification, or reconstruction after February 18, 2005. *See* 40 CFR 60.4305. Thus, these standards apply to the combustion turbines proposed for the TEC.)**

[585] **Even assuming that NSPS Subpart Da was applicable, which it is not, it would only apply to the power block, and *not* to the gasification block. This is clear from the express terms in Subpart Da itself as well as the content, or lack thereof, in USEPA's rulemaking documents associated with the promulgation of these standards. TEC could only theoretically be subject to Subpart Da if the combustion turbines were**

THE UTILITY MACT RULE

115. To the extent that IEPA may claim that the current Draft Permit includes MACT emission limits, such claims are belied by the permit conditions. The permit does not comply with the new standards of the Utility MACT Rule, also known as the Mercury and Toxic Standards (MATS) rule. This is because the TEC would burn gas derived from coal and not natural gas. CCG is attempting to avoid the EGU NESHAP rules by defining the gas produced here as "substitute natural gas" or SNG, to distinguish it from synthesis gas, which is made by IGCC plants and is covered by EGU MACT.[586] However, such an interpretation is directly at odds with the plain language of the Utility MACT Rule. This rule defines "[integrated gasification combined cycle electric utility steam generating unit or IGCC" as "an electric utility steam generating unit meeting the definition of 'fossil fuel-fired' that burns a synthetic gas derived from coal and/or solid oil derived fuel for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year in a combined-cycle gas turbine. No coal or solid oil-derived fuel is directly burned in the unit during operation." *See* 40 CFR 63.10042.

As mentioned previously, the Utility MACT Rule only applies to coal and oil-fired electric utility steam generating units (EGUs). "This final rule does not regulate a unit that otherwise meets the CAA section 112(a)(8) definition of an EGU but that combusts natural gas exclusively or natural gas in combination with another fossil fuel where the natural gas constitutes 90.0 percent or more of the average annual heat input during any 3 consecutive calendar years or 85.0 percent or more of the annual heat input in one calendar year. I consider such units to be natural gas-fired EGUs notwithstanding the combustion of some coal or oil (or derivative thereof) and such units are not subject to this final rule." *See* Final Utility MACT Rule at 26, *see also,* 40 C.F.R. § 63.9983.

The rule goes on to define "natural gas" as "a fluid mixture of hydrocarbons (*e.g.,* methane, ethane, or propane), composed of at least 70 percent methane by volume or that has a gross calorific value between 35 and 41 megajoules (MJ) per dry standard cubic meter (950 and 1,100 Btu per dry standard cubic foot), that maintains a gaseous state under ISO conditions. In addition, natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet. Finally, natural gas does not include the following gaseous fuels: landfill gas, digester gas, refinery gas, sour gas, blast furnace gas, coal-derived gas, producer gas, coke oven gas,

---

somehow found to be IGCC units, per 40 CFR 60.40Da(b) and 60.41Da. A plain reading of these subsections reveals their limited applicability.[585] In addition, the lack of any meaningful discussion of the types of units commonly found in a gasification block (e.g., gasifiers, flare, SRU, AGR unit, etc.) within the relevant rulemaking docket confirms this plain language interpretation. If USEPA had intended for Subpart Da to reach beyond the power block to units in the gasification block -- well beyond the reach of the complementary rules for combustion turbines in Subparts GG and KKKK -- surely some discussion of the emissions of flares and AGR units would have been present in the docket to support the novel application of the standards to gasification units. However, such discussion is not present in the docket.

[586] On December 21, 2011, the USEPA signed a rule to reduce emissions of toxic air pollutants from power plants (commonly referred to as the "Utility MACT Rule").[586] Specifically, these mercury and air toxics standards for power plants will reduce emissions from new and existing coal and oil-fired electric utility steam generating units. The final Utility MACT Rule identifies two subcategories of coal-fired EGUs, four subcategories of oil fired EGUs, and a subcategory for units that combust gasified coal or solid oil (integrated gasification combined cycle ("IGCC") units) based on the design, utilization, and/or location of the various types of boilers at different power plants. The rule includes emission standards and/or other requirements for each subcategory. This new rule is potentially applies to the TEC since construction has not begun yet and the Utility MACT Rule applies to facilities that commenced construction after May 3, 2011. *See* Final Utility MACT Rule at 872, 876, 982, 985; *see also* 40 CFR 63.9981, 63.9982, 63.9985 and 63.10042.

or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value." *See* Final Utility MACT Rule at 985 (emphasis added); *see also,* 40 CFR 63.9983.

Therefore, the rule unquestionably regulates IGCC plants that burn a synthetic natural gas derived from coal for more than 10.0 percent of the average annual heat input during any 3 consecutive calendar years or for more than 15.0 percent of the annual heat input during any one calendar year in a combined-cycle gas turbine. Moreover, a facility cannot claim that it is exempted from the standards of this rule if the gas it burns is a "coal-derived gas." Therefore, CCG cannot attempt to avoid the applicability of this rule by claiming it is burning a synthetic natural gas or SNG.

The comment is incorrect that the Utility MACT applies to this project. The language in the rule is subtle, but ultimately clear – natural gas burned in combustion turbines is exempt from the rule, regardless of its origin. In the final rule, the clearest definition that delineates the difference between the fuels addressed by the rule is the definition for coal, namely,

> ***Coal* means all solid fuels classifiable as anthracite, bituminous, subbituminous, or lignite by ASTM Method D388–05, ''Standard Classification of Coals by Rank'' (incorporated by reference, see § 63.14), and coal refuse. Synthetic fuels derived from coal for the purpose of creating useful heat including but not limited to, coal derived gases (*not meeting the definition of natural gas*), solvent refined coal, coal-oil mixtures, and coal water mixtures, are considered ''coal'' for the purposes of this subpart. [Emphasis added.]**

The rule is clear that it only applies to coal- and oil-fired units, and not to those fired on natural gas, regardless of the origin of that natural gas.

Also, the definition of natural gas in the rule includes language stating, "Natural gas contains 20.0 grains or less of total sulfur per 100 standard cubic feet", which is the fuel to be fired in the combustion turbines at the source. The definition later states that, as the comment correctly notes, natural gas does not include coal-derived gas.

Coal-derived gas is not inclusive of natural gas derived from coal, as the above definition for "coal" shows. In fact, in the parlance of coal gasification, coal-derived gas, or synthesis gas (also known as syngas), is certainly NOT equivalent to natural gas or substitute or synthetic natural gas (which meets the definition of natural gas), which can also be derived from coal. Syngas contains contaminants that are cleaner than raw gasified coal, but dirtier than "clean" natural gas.

The definition of natural gas in the rule excludes gases such as landfill gas, refinery gas, blast furnace gas and, as one will read at the end of the definition of natural gas, "or any gaseous fuel produced in a process which might result in highly variable sulfur content or heating value." Therefore natural gas does not include 'coal-derived gas' because of its highly variable sulfur content. On the other hand, cleaning that same coal-derived syngas to the extent of meeting the definition of natural gas, means that it

no longer falls under the category of "coal-derived gas" because its sulfur content is below 20 grains or less per 100 standard cubic feet (losing its high sulfur variability).

The Preamble to the rule, page 9334, states, "One commenter concurred with EPA that regulating natural gas-fired EGUs was not appropriate and necessary because the impacts due to HAP emissions from such units are negligible based on the results of the Utility Study", implicitly advocating the notion that once the synthesis gas has reached the cleanliness level, and hence meeting the definition of natural gas, the point of applying the NESHAP to it is needless.

In light of this review and analysis, the other points raised by this comment do not need to be further addressed. However, as the Utility MACT rule may be appealed and subsequently revised by USEPA, it should be noted that the future actions of USEPA with respect to this rules are in no way bound by the permit. In particular, if the USEPA were to adopt revisions to the rules such that utilities turbines firing natural gas or substitute natural gas produced by an associated coal gasification plant, the TEC would then be subject to the relevant provisions of the Utility MACT rule that apply to such plants.

PLANT WOULD NOT COMPLY WITH THE LIMITS IN THE UTILITY MACT RULE.

116. For all existing and new coal-fired EGUs, the final Utility MACT Rule establishes numerical emission limits for mercury, PM (a surrogate for toxic non-mercury metals), and HC1 (a surrogate for all toxic acid gases). The rule also establishes alternative numeric emission standards, including SO_2 (as an alternate to HCl), individual non-mercury metal air toxics (as an alternate to PM), and total non-mercury metal air toxics (as an alternate to PM) for certain subcategories of power plants. The Final Utility MACT Rule establishes the specific emission limits for new IGCC plants (*See* Final Utility MACT Rule at 995-96; *see also*, 40 CFR Subpart UUUUU, Table 1. Emission limits are set for mercury, PM (a surrogate for toxic non-mercury metals), and HCl (a surrogate for all toxic acid gases). The rule also establishes alternative numeric emission standards, including SO_2 (as an alternate to HCl), individual non-mercury metal air toxics[587] (as an alternate to PM), and total non-mercury metal air toxics (as an alternate to PM).

Condition 3.4(b) of the Draft Permit would only establish pollutant-specific emission limits for facility-wide emissions for lead and mercury. The limit for mercury is set at 0.1 ton/yr, which translates to an emission rate of 0.03 pounds per Gigawatt-hour ("lb/GWh") of mercury.[588] This emission rate exceeds the mercury limit set by the new Utility MACT rule for IGCCs of 0.003 lb/GWh by a factor of ten. Thus, the annual limit for mercury set by the Draft Permit (0.01 ton/yr) would not comply with the new Utility MACT rule.

A comparison with other limits set by the Utility MACT rule, [589] shows that, in addition to exceeding the emission limit for mercury, facility-wide emissions from the TEC would

[587] Antimony ("Sb"), Arsenic ("As"), beryllium ("Be"), cadmium ("Cd"), chromium ("Cr"), cobalt ("Co"), lead ("Pb"), manganese ("Mn"), nickel ("Ni"), and selenium ("Se").
[588] (0.1 ton mercury/year)(2,000 lb/ton)(1 year/8,760 hours)(1/770 MW)(1,000 MW/GW) = 0.0297 lb mercury/GWh.
[589] This comment includes a comparison of the emission limit for the TEC with the Utility MACT rule, as Table 17.

exceed the alternate Utility MACT thresholds for beryllium, cadmium, and lead. As discussed elsewhere, CCG substantially underestimated facility-wide PM emissions. As a result, facility-wide emissions of SO_2 and PM likely also exceed the Utility MACT emission limits. The issued permit must reflect the emission limits and compliance testing requirements of the Utility MACT Rule (in lb/GWh or lb/MWh) and provide adequate demonstration that these limits and requirements can be met.

With regard to the noncompliance with the mercury emission limits of the Utility MACT rule, CCG, apparently seeking to remedy this situation, requested a lower permit limit in a letter to IEPA dated November 8, 2011:

> We wish to lower the annual facility-wide mercury emission limit, as stated in Condition 3.4(b) of the draft permit, from 0.10 tons (200 pounds) per year to 0.01 tons (20 pounds) per year. This revised limit, which represents a 90% reduction, is based on the mercury limit for new coal-fired and IGCC units expected to be included in the forthcoming final National Emissions Standards for Hazardous air pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units (40 CFR Part 63 Subpart UUUUU) rule.[590]

In its letter, CCG offers to furnish revised emission calculations upon request but provides no explanation whatsoever how this 90% reduction is achievable; instead, CCG simply requests the lower permit limit to comply with the new Utility MACT Rule. This is not acceptable. CCG must provide sufficient evidence for its emission estimates which, as explained below, are the basis for its compliance calculations for HAPs including mercury.

To the extent the Utility MACT rule applies to TEC, TEC will be required to meet its limits irrespective of the terms in the permit. Notwithstanding this fact, TEC is designed to meet, and will meet, those emissions limits. The comment's comparison of the plant-wide annual potential PM, metallic HAP, HCl, SO_2, and mercury emissions from the TEC to the Utility MACT limits is misleading and incorrect. The Utility MACT only regulates emissions from the combustion turbine portion of an IGCC plant and not the entire plant. Therefore, using the plant-wide annual potential emissions presented in the Application is not an appropriate basis for comparison to the Utility MACT limits. A proper conducted comparison shows that emissions from the TEC combustion turbine would comply with all of the emission limits for new IGCC units in the Utility MACT rule.

The comment also requests additional information to justify CCG's request to reduce the plant-wide mercury emission limit in the permit from 0.10 tpy to 0.01 tpy. CCG reevaluated the mercury emissions from syngas and SNG-fired combustion sources and determined that a plant-wide emission limit of 0.01 tpy was achievable based on the average mercury content of the coal and the mercury removal efficiency of the equipment in the syngas processing train (which will include carbon adsorption beds). No further updates to the emission calculations are necessary to address this reduction

[590] Letter from Larry G. Carlson, Christian County Generation, LLC, to Dean Studer, Illinois EPA, Re: Public Comments — Taylorville Energy Center Draft Air Permit, Christian County Generation, LLC, Application No. 05040027, November 8, 2011; received from IEPA in response to FOIA request. (Commenter's Exhibit 109a)

in the mercury emission limit because the permit contains adequate testing, monitoring, recordkeeping, and reporting requirements for all sources that emit mercury. By complying with these requirements, CCG will assemble the necessary data to confirm compliance with the plant-wide mercury limit.

VIII. THE AIR QUALITY IMPACTS ANALYSES ARE FLAWED AND INADEQUATE

INTRODUCTION

117. Consultants for CCG prepared air quality dispersion modeling for the application for the TEC. This modeling is presented in an October 2010 report that outlines their modeling methodology and results.[591] IEPA reviewed, audited, and remodeled TEC's air quality modeling; however, as discussed in the Project Summary, it eventually relied solely on CCG's modeling analysis to support its permit review decisions. Both modeling was conducted using the USEPA's preferred air quality model, AERMOD, which is an acronym for the American Meteorological Society/Environmental Protection Agency Regulatory Model Improvement Committee's Dispersion Model.

Air dispersion modeling is used to demonstrate compliance with the NAAQS and PSD increments in ambient air. Modeled concentrations are added to a regional background value to determine the total concentration used in comparison to the NAAQS or increments. It is important that the emissions used in this modeling are accurate. As discussed in extensive detail above, emissions of PM_{10}, $PM_{2.5}$, and SO_2 were underestimated by using unrealistically high control efficiencies and ignoring certain sources of those emissions.

In addition, CCG's modeling includes a number of assumptions and methodologies that will under-estimate modeled air quality impacts. The under-estimates render both the permit application and IEPA's review flawed and inadequate for verifying compliance with the NAAQS and PSD increments. Specifically, TEC's modeling includes the following inappropriate methodologies:

- TEC uses non-preferred meteorological data that include an unrealistically high number of calm hours. Since calm hours cannot be used by the air dispersion model, the modeling is not properly assessing compliance with the NAAQS and PSD increments.

- TEC's modeling is based on underestimated fugitive PM_{10} and $PM_{2.5}$ emissions from transfer points and storage piles. When these PM_{10} and $PM_{2.5}$ emissions are corrected, the modeling predicts violations of the 24-hour PM_{10} NAAQS, the 24-hour PM_{10} PSD increment, and the 24-hour $PM_{2.5}$ NAAQS.

- TEC's modeling uses under-estimated flare SO_2 emissions that will occur during planned startup and shutdown. Once corrected, the modeling shows violations of the one-hour SO_2 NAAQS.

[591] Updated Prevention of Significant Deterioration and State Construction Permit Application for the Taylorville Energy Center, Christian County Generation, Taylorville, Illinois, Permit No. 05040027, Volume 2 of 3, Class II Area Air Quality Modeling Report, October 2010 ("Modeling Report").

- TEC uses an unacceptable and inappropriate set of screening tables, rather than actual air dispersion modeling, to estimate ozone impacts from the proposed project. In addition, the VOC emissions from the proposed project are greatly under-estimated in the permit application, thus making TEC's ozone analysis even more inadequate.

I identified the AERMOD model runs that TEC used as the basis for both their permit application and IEPA's project summary. These files were included in a hard drive of files provided to Sierra Club and Natural Resources Defense Council on December 14, 2011. In my modeling analysis, I used TEC's model inputs as a starting point, and then I modified the specific inputs to reflect the corrected PM_{10}, $PM_{2.5}$ and SO_2 emissions as discussed elsewhere in my comments. I also removed all the non-TEC emission sources from the model inputs. This means that all of my modeled results are due only to the proposed TEC facility. If I had included the other PSD and NAAQS-consuming sources in my analysis, the model results would be even higher than I report below.

I used AERMOD versions 11103 and 11353 for my modeling analysis. AERMOD v. 11353 was released by USEPA on 12/21/2011, and reflects the most recent version available. In my analyses of the air impacts from TEC's emissions, I found no differences in the results between these two models.

These comments discusses how revised modeling, using corrected emission rates and corrected modeling assumptions, shows how the TEC will exceed the 24-hour PM_{10} NAAQS and PSD increment, the 24-hour $PM_{2.5}$ NAAQS, and the 1-hour SO_2 NAAQS. Moreover, these comments will address why IEPA cannot rely on the analysis provided by CCG to verify compliance with the ozone NAAQS as it is fundamentally flawed.

These comments do not identify flaws in the modeling conducted for the plant, as discussed in detail below.

ACTUAL ELECTRONIC EMISSION CALCULATION SPREADSHEETS WERE NEVER PROVIDED TO IEPA SO THE PUBLIC DID NOT HAVE ADEQUATE INFORMATION TO FULLY ANALYZE THE AIR QUALITY ANALYSIS

118. The documents provided to me by IEPA included emission calculations in Adobe Acrobat.PDF file format. In this encrypted form, it is impossible to verify the numerous calculations needed for the complete TEC emission inventory. I (the Sierra Club and Natural Resources Defense Council) have reviewed many power plant applications, and the usual mode for responding to the emission calculation data request is to provide unlocked Excel spreadsheets showing the equations and assumptions as they were actually applied. The IEPA does not have any electronic form of the emission calculations, except the.PDF files sent to Sierra Club. This is disconcerting for three reasons:

1. The actual emission calculations applied in the permit application are never made available to the reviewing public. One would hope that the equations shown on the .PDF listings are the same as those actually used in the final calculations, but there is no way to know for sure unless the equations are checked by hand (many thousands

of times), or by viewing the calculations in the program used to perform the inventory (i.e., Excel spreadsheets).

2. By not having the native spreadsheets, IEPA could not itself have reviewed the facility emission calculations in a complete fashion. At best, they could only spot-check. This is highly problematic given that the emission calculations for certain pollutants, such as particulate matter, were projected to decrease by a magnitude of 10 since the last PSD application for this permit. Without these native spreadsheets it is impossible for the agency to determine if there are emission calculation errors and thus verify that this facility will not lead a violation of the NAAQS or increment consumption (without any necessary corrections to the modeling methods discussed below).

3. Emission calculation spreadsheets were obviously created by CCG, and could have been easily provided to IEPA and any reviewers requesting the files. CCG, however, has never made these Excel files available. Instead, they encrypt the data in Adobe.PDF form, where it is impossible to scrutinize what equations were actually used for the permit application.

These actions are at odds with USEPA's policy that meaningful public review requires full transparency by the applicant of its modeling work. The USEPA does not accept analyses prepared unless a transparent view of the actual applied dispersion modeling equations is provided. The USEPA Guideline on Air Quality Models states clearly: "The developer must be willing to make the model available to users at reasonable cost or make it available for public access through the Internet or National Technical Information Service: the model cannot be proprietary." Moreover, "air quality models used in U.S. regulatory programs must be in the public domain at reasonable cost. This is because the source code needs to be open for public access and scrutiny to enable meaningful opportunity for public comment on new source permits, PSD increment consumption and SIPs." [592] *In re Hawaii Elec. Light Co., Inc*, 8 E.A.D. 66, 102 (EAB 1998) (quoting CAA § 165(e)(3)(c), 42 U.S.C. § 7475(e)(3)(c)) ("Congress has determined that the air quality analysis required by the regulations 'shall be available at the time of the public hearing on the application for such permit.").

Similarly, without the actual electronic spreadsheets used to perform the TEC emission calculations, meaningful opportunity for public comment on new source permits, including compliance with NAAQS and PSD increment consumption is not possible. IEPA should require CCG to submit this information and re-do its permit analysis. *See, e.g., In re Hawaii Elec. Light Co., Inc*, 8 E.A.D. 66, 102-103 (EAB 1998) (remanding permit where data relevant to the impact analysis was not subject to the public scrutiny contemplated by the statute and applicable regulations).

Emission inputs to the model for area and volume sources were reviewed by the IEPA for consistency with other emission data in the application. Emissions inputs were either verified or adjusted in the audit modeling to reflect the proper modeled

[592] USEPA, 2003, Guideline on Air Quality Models. 40 CFR 51, Appendix W, Section 3.1.1 (c)(vi), appw_05.pdf.

emissions for the TEC. Model audit runs were performed to the satisfaction of the IEPA modeling staff and confirmed conclusions reached by TEC. As an additional response to "making models available to users," the air dispersion model AERMOD and all dispersion modeling pre-processors associated with the AERMOD suite, are freely available through USEPA.

MODELING IS BASED ON UNDERESTIMATED EMISSIONS

119. CCG submitted air quality modeling as required to ensure protection of NAAQS, but inappropriately modeled underestimated PM and SO_2 emissions instead of maximum or worst-case emissions. As already discussed in my other comments, CCG underestimated emissions of PM_{10} and $PM_{2.5}$ by excluding certain fugitive emission sources from its calculations, assuming unrealistic control efficiencies for numerous sources, and other noted problems, and underestimated SO_2 emissions by not accounting for the maximum emissions from the flares during planned startup/shutdown and failing to account for any emissions from the flares during malfunction events. Despite the fact that there are no hourly or daily emission limits on these emission points, and the fact that the pollution abatement techniques are in actuality far less effective than CCG assumed, IEPA assumed emission rates for purposes of modeling that do not reflect the worst-case emissions during the 24-hour averaging period for compliance with the PM NAAQS and PSD Increment and 1-hour averaging period for compliance with the SO_2 NAAQS. As such, the modeling carried out by CCG and IEPA does not demonstrate the requisite compliance with the applicable NAAQS and PSD Increments. In addition, upon correction of some or all of the erroneous assumptions, detailed in length above, to represent worst case conditions as required for air impact modeling, air quality modeling shows that the project does not satisfy the CAA's requirements to not violate a NAAQS or exceed an increment consumption limit. Therefore, IEPA cannot issue a PSD permit for the TEC.

The comment incorrectly asserts that the modeled emission rates for various emission units at the TEC included in the PM_{10}, $PM_{2.5}$, and SO_2 NAAQS analyses were underestimated and do not reflect the "maximum or worst-case" emissions. Responses elsewhere address the claimed underestimates of SO_2 emissions from flaring during gasification block startup and shutdown events, and underestimates of PM emissions from fugitive material storage and handling units. For the flare and fugitive PM emission sources, CCG determined modeled emission rates in accordance with Section 8.1 of the *Guideline* and the following recommendations from USEPA.

> **Consistent with past SO_2 modeling guidance (Section 4.5.2 of U.S. EPA (1994)) and regulatory modeling for other programs (Appendix W, Section 8.1), dispersion modeling for the purposes of SIP development should be based on the use of maximum allowable emissions or federally enforceable permit limits. Also consistent with past and current guidance, in the absence of allowable emissions or federally enforceable permit limits, potential to emit emissions (i.e., design capacity) should be used. Because of the short-term nature of the new**

SO_2 NAAQS, the maximum short term or hourly emission rate should be input into AERMOD for each modeled hour.[593]

In the PM_{10}, $PM_{2.5}$, and SO_2 NAAQS analyses, CCG modeled either federally enforceable short-term permit limits or the potential to emit for all of the PM and SO_2 emission sources at the TEC. The potential to emit calculations, which support the short-term permit limits and the modeled emission rates, are expected to overestimate actual emissions from the TEC. As discussed elsewhere, the sulfur conversion efficiency, total sulfur content of raw syngas, and coal sulfur content used in the maximum hourly SO_2 emission calculations for the flare are adequately supported in the permit record and result in a hourly flare BACT limit that reflects the highest SO_2 emissions expected to occur from the flare during any hour of a gasification block startup or shutdown event. The hourly flare SO_2 BACT limit is supported by comprehensive testing, monitoring, recordkeeping, and reporting requirements in the permit which will ensure that CCG can verify compliance with this limit on a continuous basis.

As discussed elsewhere, the inputs to the USEPA emission factor algorithms used to estimate fugitive PM emissions from material handling and storage emission sources are supported in the record, and these inputs result in conservatively high estimates of short-term PM emissions. The issued permit includes hourly fugitive PM emissions limits for material handling and storage sources and adequate monitoring, recordkeeping, and reporting requirements for material handling and storage PM emission sources to make the modeled emission rates for these sources enforceable.

With appropriate and conservative modeled emission rates, stack parameters, and modeled operating scenarios, the results of the NAAQS and PSD Increment analyses do "demonstrate the requisite compliance with the applicable NAAQS and PSD Increments." The comment's reference to modeling results based on alternative SO_2 and PM emissions calculations do not change the conclusions of the air quality analyses. These modeling runs simply demonstrate the direct relationship between modeled emission rates and offsite impacts, but do not represent the air impacts from the TEC since the modeled emission rates are not representative of the worst-case emissions from the TEC.

The comment also claims that the results of the SO_2 NAAQS analysis are flawed because CCG did not evaluate impacts from flaring emissions during malfunction events. As discussed elsewhere, the Modeling Guideline expressly provides that malfunctions are not considered normal operations and should generally not be included in the modeling.[594] Regardless, Conditions 3.6 and 4.1.2-1(c) require CCG to

---

[593] **USEPA Office of Air Quality Planning and Standards, Guidance for 1-hour SO_2 NAAQS SIP Submissions, Public Review Draft, September 22, 2011, available at http://www.epa.gov/airquality/sulfurdioxide/pdfs/DraftSO2Guidance_9-22-11.pdf**

[594] **USEPA's recent guidance for the 1-hr NO_2 NAAQS further supports the exclusion of intermittent emission sources which would, by definition, include the sudden, infrequent, and not reasonably preventable emissions from malfunction events. According to EPA, compliance demonstrations should be based on "emission scenarios that can logically be assumed to be relatively continuous or which occur frequently enough to contribute significantly to the annual distribution of daily maximum 1-hour concentration" because "assuming continuous operations for intermittent emissions would effectively impose an additional level of stringency beyond that intended by the level of the standard itself." Flaring emissions from malfunctions are not "emission scenarios that can logically be assumed to be relatively continuous or which occur frequently enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations."**

operate in accordance with good air pollution control practice to minimize emissions at all times including periods of startup, shutdown, malfunction or breakdown. During malfunction events, Condition 4.1.5-1(e)(iv)(A) specifically requires CCG to repair the affected equipment in the gasification block, reduce the operating rate of the gasification train, or remove the gasification train from service so that excess emissions cease as soon as practicable after identifying the malfunction. Unless CCG can demonstrate that continuing to operate meets the good air pollution control practice requirements in the permit and that the gasification block is maintained and operated so that malfunctions are infrequent, sudden, and not caused by poor maintenance or careless operation, CCG is required to immediately shut down the gasification block during a malfunction event. These requirements will ensure that the air quality impacts from any excess emission during malfunctions are minimized to the greatest extent practicable while still ensuring the safe operation of the plant.

2003 - 2007 SPRINGFIELD AIRPORT DATA USED BY CCG IS NOT THE PREFERRED DATA FOR REGULATORY MODELING APPLICATIONS

120. CCG used Springfield, Illinois Capital Airport surface data and Lincoln-Logan upper air data from 2003 through 2007 in its permit application modeling. These years are not the preferred data for modeling air impacts from the proposed plant.

USEPA's definition of preferred meteorological data includes the most recent five years of National Weather Service (NWS) data. Currently, this condition is satisfied using 2006 through 2010 Automated Surface Observing Station (ASOS) data collected at the most site-appropriate airport.

The definition of preferred data is found in EPA's Guideline on Air Quality Models. From Section 8.3.1.2 of the Guideline on Air Quality Models:

> Five years of representative meteorological data should be used when estimating concentrations with an air quality model. Consecutive years from the most recent, readily available 5-year period are preferred. The meteorological data should be *adequately representative*, and may be site specific or from a nearby NWS station.[595]

The air dispersion modeling for the application was prepared in the fall of 2010. At that date, meteorological data for years 2005 through 2009 were readily available and should have been used. When IEPA was reviewing and auditing TEC's modeling runs, meteorological data for years 2006 through 2010 were readily available.

More importantly, the meteorological data used in TEC's air quality modeling is based on airport wind measurements that include an over-stated number of calm conditions. This is a widely-known problem with airport data. In April 2011, USEPA released a revised version of AERMET, the program that creates the meteorological data sets used by AERMOD. This

---

If they were, they would not satisfy the definition of malfunction (infrequent, sudden, and not caused by poor maintenance or careless operation). Such emissions are more akin to the intermittent emissions that USEPA determined did not have to be modeled. Sources are not required to hypothesize about malfunction events and include such hypothetical emissions in the SO_2 modeling.

[595] USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, November 9, 2005, appw_05.pdf. (Commenter's Exhibit 143)

revised version of AERMET can process one-minute ASOS data, thus eliminating the reporting artifact that causes an unrealistically high number of calm hours in the data sets. From USEPA:

> Surface meteorological data collected by the National Weather Service (NWS) and Federal Aviation Administration (FAA) are often used as the source of input meteorological data for AERMOD (EPA, 2010a). A potential concern related to the use of NWS meteorological data for dispersion modeling is the often high incidence of calms and variable wind conditions reported for the Automated Surface Observing Stations (ASOS) in use at most NWS stations since the mid-1990's. In the METAR coding used to report surface observations beginning July 1996, a calm wind is defined as a wind speed less than 3 knots and is assigned a value of 0 knots. The METAR code also introduced the variable wind observation that may include wind speeds up to 6 knots, but the wind direction is reported as missing, if the wind direction varies more than 60 degrees during the 2-minute averaging period for the observation. The AERMOD model currently cannot simulate dispersion under calm or missing wind conditions. To reduce the number of calms and missing winds in the surface data, archived 1-minute winds for the ASOS stations can be used to calculate hourly average wind speed and directions, which are used to supplement the standard archive of hourly observed winds processed in AERMET (EPA, 20l0b).[596]

Furthermore, in its modeling guidance for SO_2 NAAQS designations, USEPA addresses the concern of calm hours in verifying compliance with the one-hour SO_2 NAAQS:

> In AERMOD, concentrations are not calculated for variable wind (i.e., missing wind direction) and calm conditions, resulting in zero concentrations for those hours. Since the SO_2 NAAQS is a one hour standard, these light wind conditions may be the controlling meteorological circumstances in some cases because of the limited dilution that occurs under low wind speeds which can lead to higher concentrations. The exclusion of a greater number of instances of near-calm conditions from the modeled concentration distribution may therefore lead to underestimation of daily maximum 1-hour concentrations for calculation of the design value.[597]

Although USEPA is referring to the one-hour SO_2 NAAQS in this particular instance, the concern regarding over-stated calm hours in the modeling data sets is also a problem when modeling other pollutants such as PM_{10} and $PM_{2.5}$. This will be verified in my modeling comments on PM_{10} and $PM_{2.5}$ emissions presented below, which show significantly higher modeled impacts with my 2006 through 2010 meteorological data than from 2003 through 2007 data, as used by CCG.

The 2003 through 2007 data sets modeled by CCG include 4,253 calm hours, or about 10 percent of the entire database. IEPA should have re-analyzed TEC's modeling using 2006 through 2010 meteorological data with one-minute ASOS data, and then used those years as

[596] USEPA, AERMINUTE User's Instructions, aerminute_userguide_l 1325.pdf. (Commenter's Exhibit 144)
[597] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, p. 19, SO_2 Designations Guidance 201 1-ocr.pdf. (Commenter's Exhibit 143)

the basis for their permit review decisions. The application modeling analysis is flawed from the beginning since both CCG and the IEPA rely on non-preferred meteorological data with an unrealistically high number of calm hours.

In my review of the permit application modeling (and also to address USEPA's concerns regarding calm winds), I developed 2006 through 2010 meteorological data that incorporate methods to reduce calm and missing hours (e.g. use one minute data and USEPA's AERMINUTE program). The meteorological data required by AERMOD is prepared by AERMET. Required data inputs to AERMET are: surface meteorological data, twice-daily soundings of upper air data, and the micrometeorological parameters surface roughness, albedo, and Bowen ratio. AERMET creates the model-ready surface and profile data files required by AERMOD.

The 2006 through 2010 data sets I developed include 485 calm hours, or roughly one percent of the entire database. Most of these calm hours (375 out of 485) occurred during 2006. For years 2007 through 2010 there are only 110 total calm hours in my revised data set. As will be shown below, this preferred meteorological data set results in higher modeled impacts than the 2003 through 2007 data sets used in the modeling in the application.[598]

[598] A brief description of how I prepared the 2006 through 2010 data sets is as follows:
• Using AERMET v. 11059, I created an AERMOD-ready meteorological data set to model the proposed TEC facility. This data set covered five years, 2006 through 2010, and includes surface data from Springfield Capital Airport (KSPI) and upper air data from Lincoln-Logan County Airport (KILX).
• 2006 through 2010 Integrated Surface Hourly (ISH) data obtained from the National Climatic Data Center (NCDC) was used. These data are readily available from yearly DVDs sold by NCDC or can be downloaded from their website. From the ISH dataset, I extracted ASOS data from the Springfield Capital Airport. This is the same location for surface data that were used by the Applicant and IEPA; however, I used the most recent preferred data with one-minute ASOS winds as described below.
• 2006 through 2010 one-minute ASOS wind data from the Springfield Capital Airport was obtained and processed with AERMINUTE versions 11059 and 11325. AERMINUTE v. 11325 was released by USEPA on 12/21/2011, and reflects the most recent version available. In the comparison analyses of the AERMOD-ready meteorological data sets created using one-minute ASOS wind data, no differences were found in the results between these two versions. The one-minute data from the NCDC was downloaded. (See: ftp://ftp.ncdc.noaa.gov/pub/data/asos-onemin/) The ice-free wind instrument start was used with default settings with AERMINUTE (9/25/2006). As a quality assurance measure, values developed from the one-minute data were compared with the corresponding ISH data file.
• I processed the ISH and one-minute ASOS surface data through AERMET Stage 1, which performs data extraction and quality control checks. I merged the AERMINUTE output files with the processed AERMET Stage 1 ISH and upper air data in AERMET stage 2.
• I used 2006 through 2010 upper air data from twice-daily radiosonde measurements obtained from Lincoln-Logan, IL. These data are in Forecast Systems Laboratory (FSL) format which I downloaded in ASCII text format from NOAA's FSL website. (Available at: http://esrl.noaa.gov/raobs/.) I downloaded and processed all reporting levels with AERMET. (Upper-air data are collected by a "weather balloon" that is released twice per day at selected locations. As the balloon is released, it rises through the atmosphere, and radios the data back to the surface. The measuring and transmitting device is known as either a radiosonde, or rawindsonde. Data collected and radioed back include: air pressure, height, temperature, dew point, wind speed, and wind direction.) I processed the FSL upper air data through AERMET Stage 1, which performs data extraction and quality control checks.
• I used USEPA's AERSURFACE program for extracting surface roughness, albedo, and daytime Bowen ratio for an area surrounding the ASOS site at Springfield Capital Airport. AERSURFACE uses land use and land cover (LULC) data in the U.S. Geological Survey's 1992 National Land Cover Dataset to extract the necessary micrometeorological data. I used these 1992 LULC data for processing meteorological data sets which then serve as input to AERMOD.
• I used AERSURFACE v. 08009 to develop surface roughness, albedo, and daytime Bowen ratio values in a region surrounding the meteorological data collection site (Springfield Capital Airport). Using AERSURFACE, I extracted surface roughness in a one kilometer radius surrounding the data collection site. I also extracted Bowen ratio and albedo for a 10 kilometer by 10 kilometer area centered on the meteorological data collection site. I processed these micrometeorological data for seasonal periods using 30-degree sectors.
• I developed variable Bowen ratios, based on precipitation for each season and each year (2006 through 2010). I determined the seasonal moisture conditions (wet, average, dry) using 1981 through 2010 climatic mean monthly rainfall data for the Springfield Capital Airport. (See http://www.ncdc.noaa.gov/oa/climate/normals/usnormals.html.) For each season of each year, I compared the seasonal total rainfall to climatic means for that season. Seasonal rainfall less than 75% of climatic means was assessed as dry. I assessed seasonal rainfall greater than 125% of climatic means as wet. (See http://www.ncdc.noaa.gov/oa/climate/normals/usnormals.html.) A Table of the precipitation conditions for determining seasonal Bowen ratios from Springfield Capital is included in Exhibit 151 (see modeling-attach-1.pdf).
• I did not fill missing hours in the meteorological data sets as the data files easily exceed USEPA's 90% data completeness requirement. See USEPA Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, Section 5.3.2, pp. 5-4 to 5-5.) Annual wind roses of the AERMOD-ready meteorological data sets I created, individually by year for 2006 through 2010 for Springfield/Lincoln-Logan, are also included in Exhibit 151 (see modeling-attach- 1.pdf).

To update the modeling analysis from the June 2007 PSD permit and to be consistent with current guidance on meteorological datasets for regulatory dispersion modeling, a more current meteorological dataset for the most recent, readily available 5-year time period was used for this permit action. Because IEPA determines surface characteristics for use as Stage 3 inputs to AERMET and this process takes a considerable amount of time for all of the National Weather Service (NWS) meteorological stations in Illinois, the most recent dataset available at the time CCG's modeling was formally initiated in January 2010 was the period from 2003 to 2007.[599] This meteorological approach is consistent with the *Guideline on Air Quality Models* (40 CFR Part 51 Appendix W, herein referred to as the *Guideline*) recommendations.

In the protocol for the current permit action, meteorological data for the Springfield Capitol Airport (surface data for the NWS Site No. 93822, KSPI) and the Lincoln Logan County Airport (upper air sounding data for NWS Site No. 04833, KILX) were proposed to be used to generate AERMOD-ready meteorological datasets for the dispersion modeling at the TEC.[600] Relevant criteria identified in the *Guideline* for demonstrating the representativeness of the data from a candidate meteorological station were described in the protocol including: 1) the proximity of the meteorological monitoring site to the area under consideration, 2) the complexity of the terrain, 3) the exposure of the meteorological monitoring site, and 4) the period of time during which data are collected.[601] The Springfield airport was determined to be representative of the TEC site based on this criteria.

The comment also states that the meteorological data used in TEC's air quality modeling is based on airport wind measurements that include an over-stated number of calm conditions. Calm conditions are addressed appropriately in the models. The identification of calm winds in USEPA models and their subsequent treatment as non-contributing periods of time to the transport of air pollutants in the models has been a long-standing policy.

CCG used the USEPA model approved at the time the protocol and final modeling was submitted (January 2010 and October 2010, respectively. The version of AERMET used in this comment for the updates to small portions of the TEC modeling analysis

---

[599] ***Class II Area PSD Air Quality Modeling Protocol Christian County Generation Taylorville, Illinois*, Project 091801.0007, Trinity Consultants, Covington, Kentucky, January 2010.**

[600] **AERSURFACE was run by IEPA to produce meteorological surface conditions surrounding the met tower in Springfield, using protocols agreed to with staff of USEPA Region 5 and the state permitting authorities in Region 5. Output data was furnished to the environmental consultant representing TEC to process the meteorological data used in the modeling of this project. Independent processing of AERSURFACE absent the Region 5 protocols can produce variations in the final form of the met data produced for use with AERMOD, in this PSD air quality analysis.**

[601] **The Springfield airport station is just 47 km northwest of the TEC, and therefore, it lies in the same climatological regime as the TEC and is expected to experience very similar ambient temperature and wind patterns. The elevations of the Springfield airport station (179 m) and the TEC (187 m) are very similar, and the surrounding terrain for both the airport and plant site are generally flat with only small variations in elevations associated with slightly undulating terrain primarily near rivers and streams. The elevations present in the modeling receptor grid which extends 50 km in all directions from the TEC and encompasses the Springfield airport station range from 159 to 233 m. This elevation data generally reflects the flat terrain in the modeling study area and similarity of the terrain at the plant and meteorological stations. Finally, the period of time selected for the modeling analysis should be representative of the range of conditions that would be experienced at both the plant site and meteorological stations over any recent 5-year period and especially the 2006 to 2010 period selected for the comment's updated modeling. As indicated by aerial photography collected in the period from 1993 to 2010 for the Springfield airport made available on Google Earth, no major changes to the surrounding land use occurred in the period from 2003 to 2010 that could affect the wind flow measured at the anemometer. Therefore, any 5-year dataset in this period should provide similar ranges of temperature, wind speed, wind direction, and cloud cover that would ultimately create similar AERMOD meteorological input files.**

was not issued until February 2011. An update of the hundreds of individual modeling runs that support the TEC's modeling analysis based on new meteorological inputs was not required as the modeling submitted complied with the approved protocol and used EPA approved models.[602]

The comment's approach to blindly applying new modeling tools on a retrospective basis to modeling scenarios based on previous versions of the modeling system is fundamentally flawed since it ignores the regulatory timeframes involved with air permitting approvals and overlooks many other refinements to the model setup that would have been implemented had the analysis been originally conducted using these newer modeling tools.[603]

REVISED MODELING RESULTS, USING CORRECTED PM10 EMISSION RATES, EXCEED THE 24-HOUR PM10 NAAQS AND PSD INCREMENT

121. CCG's PM_{10} emissions were obtained as modeled in support of their permit application and corrections were made. The basis for these corrected emissions is discussed infra. CCG's PM_{10} emissions were remodeled with the revisions, using USEPA's AERMOD air dispersion model. In addition, all of the non-TEC PM_{10} emission sources were removed from the modeling analyses. Thus the PM_{10} modeling results are due solely to the proposed TEC project emissions.

Two meteorological data sets were modeled: CCG's 2003 through 2007 data and my 2006 through 2010 data using one-minute ASOS winds. For my PM_{10} modeling analysis I used the same background 24-hour PM_{10} concentration used by CCG (49 $\mu g/m^3$).[604] Using CCG's 2003 through 2007 meteorological data, TEC's corrected PM_{10} emissions result in a 183.4 $\mu g/m^3$ highest second-high 24-hour air concentration. When added to the background concentration (49 $\mu g/m^3$), the total one-hour PM_{10} concentration is 232.4 $\mu g/m^3$. This is a violation of the 24-hour PM_{10} NAAQS, with or without adding the background concentration. Based on CCG's 2003 through 2007 meteorological data, TEC's highest

[602] **USEPA rarely determines that previous versions of models or preprocessors are in error, but rather that more current or better science is introduced into current or future models. If USEPA did, in fact, issue such statements of retroactive remodeling every time a model or meteorological change took place, most past modeling performed in support of permit issuance, air impacts, and operating limits linked to ambient impacts would be null and void. But in the interest of best science, the modeling community recognizes that past studies and the use of previously respected meteorological datasets is a valid way of conducting air dispersion modeling studies. Otherwise, every project would continually be "waiting" for the next generation model, for the next meteorological data set to be collected, for a next generation of good science, and no studies would ever come to fruition.**

[603] **The approach presented in the comment does not result in better estimates of impacts. For the TEC facility, low level point and fugitive sources and taller stacks were considered in the modeling under all meteorological conditions included in the 2003-2007 data. These data represent a wide range of wind speeds, wind directions, and atmospheric stability. The physical differences between these source types, heights of release, plume rise, and distances between sources and receptors each determine whether the dispersion modeling analysis provides representative concentration estimates. Under low wind speed conditions, the models have tended to underestimate both the effects of transport (wind speed) and turbulence resulting in highly conservative concentration estimates. Generally, tall stacks have a plume that is far above the ground and have maximum ground-level concentrations in convective, daytime situations when plume mixing is greater or in high wind conditions when plume rise is less, plumes are closer to the ground, and mechanical turbulence is greater. For a fugitive emission unit the concentrations will likely be higher under low wind speed conditions, but plume meander (as accounted for in AERMOD) and limited mixing height conditions in the same wind speed scenarios can also affect concentrations. The inclusion of more low wind speed hours (as purported by the comment) potentially resulting in higher air quality impacts may not be true across all pollutants given that the combined consideration of the taller stacks and low level fugitives units at TEC may result in either a net increase or decrease in impacts with lower winds. Thus, just because the models may give higher concentrations with lower wind speeds and lower wind speed measurements are now possible by using new advanced technology anemometers does not guarantee that consideration of more low wind speed cases is the most representative of the model's performance or of ambient impacts. It is therefore appropriate and reasonable to rely on accepted meteorological data and accepted models that address low wind speeds.**

[604] Modeling Report, p. 5-6.

second high 24-hour PM_{10} concentration (183.4 µg/m^3) also violates the 24-hour PM_{10} PSD increment (30 µg/m^3). Other modeled years show similar results. Using my 2006 through 2010 meteorological data developed from one-minute ASOS winds, TEC's corrected PM_{10} emissions result in a 208.2 µg/m^3 highest second-high 24-hour air concentration. When added to the background concentration (49 µg/m^3), the total one-hour PM_{10} concentration is 257.2 µg/m^3. This is a violation of the 24-hour PM_{10} NAAQS, with or without adding the background concentration. Based on my 2006 through 2010 meteorological data, TEC's highest second-high 24-hour PM_{10} concentration (208.2 µg/m^3) also violates the 24-hour PM_{10} PSD increment (30 µg/m^3). Other modeled years show similar results.[605]

Emissions were not underestimated, therefore the modeling results provided with this comments are irrelevant.

REVISED MODELING RESULTS, USING CORRECTED PM2.5 EMISSION RATES, SHOW THE 24-HOUR $PM_{2.5}$ NAAQS WOULD BE EXCEEDED

122. CCG's $PM_{2.5}$ emissions were obtained as modeled in the application and corrections were made. The basis for the corrected emissions is discussed infra.

CCG's corrected $PM_{2.5}$ emissions were remodeled using USEPA's AERMOD air dispersion model. In addition, all of the non-TEC $PM_{2.5}$ emission sources were removed from the modeling analyses. Thus the $PM_{2.5}$ modeling results are due solely to the proposed TEC project emissions.

Two meteorological data sets were modeled: CCG's 2003 through 2007 data and my 2006 through 2010 data using one-minute ASOS winds. For my $PM_{2.5}$ modeling analysis, I used the same background 24-hour $PM_{2.5}$ concentration used by CCG (28 µg/m^3).[606]

Using the CCG's 2003 through 2007 meteorological data, TEC's corrected $PM_{2.5}$ emissions result in a 19.8 µg/m^3 five-year average highest 24-hour air concentration. When added to the background concentration (28 µg/m^3), the total 24-hour PM_{10} concentration is 47.8 µg/m^3. This is a violation of the 24-hour $PM_{2.5}$ NAAQS. Using my 2006 through 2010 meteorological data developed from one-minute ASOS winds, TEC's corrected $PM_{2.5}$ emissions result in a 28.3 µg/m^3 five-year average highest 24-hour air concentration. When added to the background concentration (28 µg/m^3), the total 24-hour PM_{10} concentration is 56.3 µg/m^3. This is a violation of the 24-hour $PM_{2.5}$ NAAQS**.**[607]

Emissions were not underestimated, therefore the modeling results provided with this comment are irrelevant.

REVISED MODELING RESULTS, USING CORRECTED FLARE SO_2 EMISSION RATES, EXCEED THE ONE-HOUR SO_2 NAAQS

[605] Tables with the results of the modeling addressed in this comment accompanied the comment.
[606] Modeling Report, p. 5-7.
[607] Tables with the results of the modeling addressed in this comment accompanied the comment.

123. The one-hour SO_2 NAAQS takes the form of a three-year average of the 99th-percentile of the annual distribution of daily maximum one-hour concentrations, which cannot exceed 75 ppb[608]. Compliance with this standard is verified using USEPA's AERMOD air dispersion model, which produces air concentrations in units of µg/m^3. The one-hour SO_2 NAAQS of 75 ppb equals 196.2 µg/m^3, and this is the value I used for determining whether TEC's one-hour SO_2 impacts exceed the NAAQS.[609] The 99th-percentile of the annual distribution of daily maximum one-hour concentrations corresponds to the fourth-highest value at each receptor for a given year.

TEC's project-specific one-hour SO_2 ambient air impacts (highest-fourth-high) are based on the 99th percentile of the annual distribution of daily maximum one-hour concentrations averaged across the five years of modeled meteorological data. The total concentration values are the sum of TEC's air impacts and the same 99th-percentile background SO_2 concentrations used by CCG (49.8 µg/m^3).[610]

I obtained CCG's SO_2 emissions as modeled in support of its per its application, and revised the maximum hourly SO_2 flaring emissions. I developed two revised maximum hourly SO_2 flaring emissions, ranging from 12,048 to 20,080 lb/hr. The basis for these revised maximum hourly SO_2 flaring emissions is discussed infra. I remodeled the lower of the two revised hourly SO_2 flaring emissions (12,048 lbs/hr) as 1518.05 grams/sec. I remodeled the higher of the two revised hourly SO_2 flaring emissions (20,080 lbs/hr) as 2530.08 grams/sec.

I remodeled CCG's SO_2 emissions, with the above revisions, using USEPA's AERMOD air dispersion model. In addition, I removed all of the non-TEC emission sources from my modeling analyses. Thus my modeling results are due solely to the proposed TEC project emissions. I also modeled the revised SO_2 emissions using two meteorological data sets: CCG's 2003 through 2007 data and my 2006 through 2010 data using one-minute ASOS winds. Thus my one-hour SO_2 air quality modeling analyses consists of four scenarios, two meteorological data sets each modeled with two revised maximum hourly SO_2 flaring emission rates: Scenario 1: SO_2 flaring emission rate of 12,048 lbs/hr, with CCG's 2003 through 2007 meteorological data; Scenario 2: SO_2 flaring emission rate of 20,080 lbs/hr. modeled with CCG's 2003 through 2007 meteorological data; Scenario 3: SO_2 flaring emission rate of 12,048 lbs/hr, with my 2006 through 2010 meteorological data developed from one-minute ASOS winds; and Scenario 4: 20,080 lbs/hr, with my 2006 through 2010 meteorological data developed from one-minute ASOS winds.[611]

---

[608] USEPA, Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard, August 23, 2010, appwso2.pdf.

[609] The ppb to µg/m^3 conversion is found in the source code to AERMOD v. 11103, subroutine Modules. The conversion calculation is 75/0.3823 = 196.2 µg/m^3.

[610] Modeling Report, p. 5-6.

[611] Scenario 1: Revised maximum hourly SO_2 flaring emission rate of 12.048 lbs/hr. modeled with the CCG's 2003 through 2007 meteorological data.
For this scenario, TEC's emissions result in a 165.4 µg/m^3 five-year average fourth-highest daily maximum one-hour SO_2 concentration. When added to the background concentration (49.8 µg/m^3), the total one-hour SO_2 concentration is 215.2 µg/m^3. This is a violation of the one-hour SO_2 NAAQS.
Scenario 2: Revised maximum hourly SO_2 flaring emission rate of 20.080 lbs/hr. modeled with CCG's 2003 through 2007 meteorological data.
For this scenario, TEC's emissions result in a 272.8 µg/m^3 five-year average fourth- highest daily maximum one-hour SO_2 concentration. When added to the background concentration (49.8 µg/m^3), the total one-hour SO_2 concentration is 322.6 µg/m^3. This is a violation of the one-hour SO_2 NAAQS, with or without adding the background concentration.
Scenario 3: Revised maximum hourly SO_2 flaring emission rate of 12,048 lbs/hr. modeled with my 2006 through 2010 meteorological data developed from one-minute ASOS winds.
For this scenario, TEC's emissions result in a 180.7 µg/m^3 five-year average fourth-highest daily maximum one-hour SO_2 concentration. When added to the background concentration (49.8 µg/m^3), the total one-hour SO_2 concentration is 230.5 µg/m^3. This is a violation of the one-hour SO_2 NAAQS.

Each of my four modeled SO_2 flaring emission scenarios show that the proposed TEC project will cause violations of the one-hour SO_2 NAAQS. IEPA should not issue TEC's permit until specific conditions exist that ensure SO_2 flaring emissions will not cause violations of the one-hour SO_2 NAAQS.[612]

Emissions were not underestimated. Therefore the modeling results provided in the comments are irrelevant.

TEC HAS FAILED TO VERIFY COMPLIANCE WITH THE OZONE NAAQS

124. Single-source modeling for ozone was one of the more important topics discussed at the recently-held Ninth Conference on Air Quality Modeling.[613] With respect to ozone, the revised 0.075 ppm 8-hour NAAQS brings additional areas into nonattainment status or in danger of becoming nonattainment, heightening the need for rigorous analysis of ozone impacts from major emission sources. This situation should be of paramount importance to IEPA, as numerous areas in Illinois are exceeding the 0.075 ppm 8-hour NAAQS. In Illinois, the Chicago Metropolitan, Metro East, North Illinois, West-Central Illinois, East Central, and Southeast areas all exceed the 0.075 ppm 8-hour NAAQS. [614] Significantly large areas to the northeast and southwest of the proposed project site are currently nonattainment for the ozone NAAQS.[615]

Rather than using single-source air dispersion modeling for their ozone analysis, TEC assesses ozone impacts from their proposed project using a simple set of screening tables. Specifically, Section 3.4 of CCG's Modeling Report relies solely on the simple and inappropriate "Scheffe Tables" for assessing ozone impacts from the project's major stationary source emissions.[616] IEPA should have rejected this insufficient analysis.

Regarding the applicability of these tables, Dr. Richard Scheffe (the developer of the tables used by CCG) has issued a memo clearly stating that the method is, and has always been, inadequate for assessing project ozone impacts. Dr. Scheffe explains:

> I developed the screening tables in 1988 as a screening test to estimate the contribution to ambient ozone associated with increased non-methane organic carbon (NMOC) emissions arising from new or modified point sources. The tables never achieved a level of EPA certification associated with EPA guideline models and consequently were not endorsed by the Agency. After publication (non-peer reviewed literature) of the tables in 1989, the American Petroleum Institute enlisted renowned atmospheric modeling experts, Drs. John Seinfeld and Panos

---

Scenario 4: Revised maximum hourly SO_2 flaring emission rate of 20,080 lbs/hr. modeled with my 2006 through 2010 meteorological data developed from one-minute ASOS winds.
For this scenario, TEC's emissions result in a 300.8 $\mu g/m^3$ five-year average fourth- highest daily maximum one-hour SO_2 concentration. When added to the background concentration (49.8 $\mu g/m^3$), the total one-hour SO_2 concentration is 350.6 $\mu g/m^3$. This is a violation of the one-hour SO_2 NAAQS, with or without adding the background concentration.

[612] Tables with the results of the modeling of each scenario addressed in this comment accompanied the comment.
[613] http://www.epa.gov/scram001/9thmodconfpres.htm.
[614] http://www.epa.state.il.us/air/ozone/exceedances.html.
[615] http://www.epa.gov/oaqps001/greenbk/map8hr.html.
[616] Modeling Report, pp. 3-13 — 3-15.

> Georgopoulous of the California Institute of Technology, to review the technique. Based on their input and my own analysis, the EPA decided at that time that the tables did not adhere to an adequate level of scientific credibility to be recommended for their intended purpose.
>
> Ozone science has advanced markedly since 1988 with substantial improvements in the characterization of emissions, meteorological, and atmospheric chemistry processes, paralleling an equivalent improvement in computational processing capability, all of which constitute the principal features of a modeling framework. As a result, the Scheffe method, which was deemed "not adequate" in 1989, would be even less adequate today.[617]

Given the nature of TEC's NO_x and VOC emissions and resulting ozone concentrations, there is no justification for IEPA to rely on the Scheffe Point Source Screening Tables for verifying compliance with the new 8-hour ozone NAAQS of 0.075 ppm. The USEPA agrees with Dr. Scheffe that given the current state of the art, this technique is inappropriate for assessing ozone impacts. From USEPA's analyses regarding *Approval and Promulgation of Implementation Plans; Kentucky; 110(a)(1) and (2) Infrastructure Requirements for the 1997 8-Hour Ozone National Ambient Air Quality Standards:*

> EPA agrees that States should not be using inappropriate analytical tools in this context. For example, the Commenter's Exhibit 14 does discuss the inappropriateness of using a screening technique referred to as the "Scheffe Tables.'' The Commenter is correct that the use of ''Scheffe Tables'' and other particular screening techniques, which involve ratios of nitrogen oxides (NOx) to volatile organic compounds (VOC) that do not consider the impact of biogenic emissions, or that use of other outdated or irrelevant modeling is inappropriate to evaluate a single source's ozone impacts on an air quality control region. More scientifically appropriate screening and refined tools are available and should be considered for use.[618]

It is important to note that facilities in USEPA Region VI have recently used photochemical grid models for ozone impact assessments. For example, two recently proposed major source facilities prepared ozone impact analyses using CAMx and associated SIP modeling episodes. The proposed facilities are NRG Limestone 3, a coal-fired power plant in Texas, and Nucor Steel Louisiana. There is no reason why IEPA should allow TEC to use a clearly inadequate ozone assessment, when Texas and Louisiana are requiring state-of-the-art photochemical grid models. Moreover, TEC's VOC emissions are greatly under-estimated, thus further invalidating CCG's simple "back-of-the-envelope" ozone analysis. *See* discussion infra regarding underestimated VOC emissions.

Clearly, CCG failed to verify compliance with the 8-hour ozone NAAQS of 0.075 ppm. IEPA must deny CCG's permit application until appropriate air dispersion modeling is performed that demonstrates compliance with this standard.

---

[617] Letter from Dr. Richard Scheffe to Ms. Abigail Dillen (July 28, 2006), (Commenter's Exhibit 129), Scheffe Memo 7_28_06.pdf
[618] Federal Register, Vol. 76, p. 41097, July 13, 2011,.

The Scheffe Tables are an appropriate technique to address the impact of the TEC on ozone air quality. This is particularly true because of the relatively low emissions of ozone precursors from the plant and the location of the plant in an area that has good air quality for ozone. As discussed by this comment, analysis of the impact of a single facility on ozone air quality continues to be a challenge. This is because ozone is formed in the atmosphere from precursor compounds by photochemical reaction. The USEPA has not developed an appropriate tool for routine single source ozone modeling other than the Scheffe Tables. Photochemical grid modeling, as used for analyses of ozone air quality in major metropolitan areas as part of attainment planning, is not an appropriate tool for this purpose in an area like that in which the TEC is proposed to be located. This is because the necessary preparatory work for use of such a model, including area-specific model verification, has not occurred. The Scheffe Tables provide a reasonable technique to assure that a proposed project will not pose a threat to ozone air quality. The use of these tables provides the user the ability to develop an answer to the question of ozone impact of a single proposed source or facility modification, in combination with a conservative ozone background concentration, relative to the ozone NAAQS. Moreover, because of their simplicity, they yield a more conservative estimate than would be anticipated through photochemical modeling. In this regard, it is noteworthy that the Scheffe Tables are a screening technique for evaluation of ozone impacts and could be followed by additional analyses if they indicated possible exceedances of the ozone NAAQS.

This comment references two communications discouraging the use of the Scheffe Tables. One is a letter to attorney Abigail Dillen of Earth Justice from Dr. Scheffe (originator of the Scheffe tables, for estimating ozone concentrations from a single source). The other is a Federal Register notice for the Kentucky ozone SIP, which was published on July 13, 2011. While Dr. Scheffe describes the use of the tables as being inadequate and also cites an American Petroleum Institute pronouncement that the tables are lacking in scientific credibility, his letter does not say in what way. Considering that potentially affected entities and interest groups would have an objection to these tables, the American Petroleum Institute position provides some indirect confirmation of the conservative nature of the Scheffe screening tables. While Dr. Scheffe states that USEPA has not formally endorsed their use, USEPA has also not endorsed a particular approach to addressing ozone contributions from proposed or modified sources under PSD. The Federal Register notice that the comment cites, also states that the state reviewing authority and the regional USEPA office must confer on air quality matters regarding the approach to developing an ozone air quality analysis. USEPA Region 5 has given IEPA permission in the past to use the screening tables methodology and has not objected to its use in numerous PSD permit applications where VOCs exceed 40 tons per year.

Since the ozone ambient impact analysis for the TEC relied on the Scheffe Tables, the comment further claims that TEC failed to verify compliance with the 8-hour ozone NAAQS of 0.075 ppm, and thus, should be required to conduct an appropriate air dispersion modeling analysis to demonstrate compliance with the ozone NAAQS. Single source modeling generally is not required under the CAA for demonstrating compliance with the ozone NAAQS. The EAB considered whether single source

modeling is required and found otherwise. *See generally In re Prairie State Generating Co.*, 13 E.A.D. 1 (EAB 2006), *aff'd¸Sierra Club v. EPA*, 499 F.3d 653 (7th Cir. 2007) (accepting the IEPA's conclusion that ozone models are not applicable to a single source). In *Prairie State,* the EAB found that "while both the [CAA] and the implementing regulations prohibit the issuance of a PSD permit without a demonstration that the proposed source will not cause or contribute to an exceedance of the applicable NAAQS, neither the statute nor the regulations define with precision what an applicant must do to make the required demonstration." *Id.* at 97.

Section 3.4 of the TEC application modeling report recognizes that ground-level ozone concentrations are the result of photochemical reactions among various chemical species. These reactions are more likely to occur under certain ambient conditions (e.g., high ground-level temperatures, light winds, and sunny conditions). The pollutants that contribute to ozone formation, referred to as ozone precursors, include NOx and VOM from both anthropogenic (e.g., mobile and stationary sources) and natural sources (e.g., vegetation). The proposed TEC plant will not directly emit ozone. Thus, TEC was required to conduct an ozone impact analysis as part of the PSD air quality analyses.

Section 5.1 of Appendix W, *Guideline on Air Quality Models* states that "Models for ozone are needed primarily to guide choice of strategies to correct an observed ozone problem in an area not attaining the NAAQS for ozone." [619] The area surrounding the TEC site is clearly an attainment area for ozone and such a strategic application of a photochemical dispersion model is not warranted. The *Guideline* goes on to recommend in Section 5.2.1 Models for Ozone that photochemical models for "multi-source applications" should include models that consider ozone on the basis of complex source interaction and photochemical-atmospheric reactions, again with respect to area with known "ozone problems". The area near and within an area encompassing over 100 km of the proposed TEC site is not an area with known ozone problems. Because this source is to be located distant from the ozone nonattainment areas to the north-northeast, i.e., the Chicago metro area (over 250 km distant) and to the southwest, i.e., the St, Louis metro area (over 130 km distant and in an upwind direction), impacts on nonattainment status are expected to be negligible. Section 5.2.1.c goes on to say that the most suitable approach for ozone modeling of an individual source should be determined with the consultation of the regional office. Such consultation was considered over the course of this analysis with the IEPA providing the approved screening method used (referenced in the IEPA PSD modeling guidance at the time of analysis). [620]

A recent letter from the USEPA Assistant Administrator goes on to state USEPA's current position on the subject of single source modeling for ozone impacts. Ms. McCarthy acknowledges the significant challenges in assessing the impacts of individual stationary sources on ozone formation. [621] USEPA has not in the past

---

[619] *Guideline on Air Quality Models*, 40 CFR 51, Appendix W, November 5, 2005.
[620] IEPA, *Prevention of Significant Deterioration – The Art and Science of the PSD Air Quality Analysis The Modeling Perspective*, October 10, 2008.
[621] Letter response from Gina McCarthy, EPA Assistant Administrator to Robert Ukeiley (on behalf of the Sierra Club), January 4, 2012.

recommended any such individual source models or required permitting authorities to implement ozone ambient impact analysis methodologies that are based on modeling. In this letter, USEPA goes on to say that the consideration of "generally-applicable guidelines that identify particular analytical techniques or models for assessing the impacts of an individual source on ozone concentrations" may now be reasonable and will be discussed further at the 10th Conference on Air Quality Modeling on March 13-15, 2012. But such techniques are yet not available. A workgroup will be formed to address technical approaches and models for ozone, will make their findings publically available, and will consider the specifics of any proposed rule at the 11th Conference on Air Quality Modeling which is scheduled in 2015 based on the every three-year cycle. Thus, future approval of a recommended model for individual source modeling is not imminent and the states and regions are left to their own preferred methods as in the case of TEC. Given the levels of ozone at nearby monitors to the proposed TEC site that are well within compliance of the 8-hour NAAQS, the lack of approved methodologies and models for ozone impacts due to individual sources, and the general approval of the method used for the current analysis for projects in Illinois, An appropriate and adequate analysis has been performed demonstrating compliance with the ozone NAAQS.

IX. ENFORCEABILITY

PRACTICAL ENFORCEABILITY OF PERMIT LIMITS

125. The Clean Air Act (CAA) requires permits be practically enforceable. The USEPA has emphasized that point. The NSR Manual, Section B.V specifically requires that the BACT provisions in a permit be practically enforceable.[622, 623] "Practicable enforceability" means that a permit's provisions must specify:

---

[622] The NSR Manual, at B.56, provides "The emissions limits must be included in the proposed permit submitted for public comment, as well as the final permit. BACT emission limits or conditions must be met on a continual basis at all levels of operation (*e.g.*, limits written in pounds/MMBtu or percent reduction achieved), demonstrate protection of short term ambient standards (limits written in pounds/hour) and be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements).

Consequently, the permit must: 1) Be able to show compliance or noncompliance (*i.e.*, through monitoring times of operation, fuel input, or other indices of operating conditions and practices); and 2) Specify a reasonable averaging time consistent with established reference methods, contain reference methods for determining compliance, and provide for adequate reporting and recordkeeping so that the permitting agency can determine the compliance status of the source."

[623] Since the PSD Permit terms and conditions will also eventually be incorporated as part of the TEC's federal Title V operating permit at the state level, law and guidance on enforceability in the Title V context also are instructive. Pursuant to the Clean Air Act, Title V permits are to include, among other conditions, "*enforceable* emission limitations and standards, ... and such other conditions as are necessary to assure compliance with applicable requirements of [the Act], including the requirements of the applicable implementation plan." 42 U.S.C. § 7661c(a) (emphasis added). USEPA policy requires Title V permits to be "enforceable as a practical matter."[623] Thus, to be enforceable, the permit must create mandatory obligations (standards, time periods, methods). Specifically, a permit condition must: (1) provide a clear explanation of how the actual limitation or requirement applies to the facility; and (2) make it possible for the [state agency], the USEPA, and citizens to determine whether the facility is complying with the condition. *See, e.g., Sierra Club v. Ga. Power Co.*, 365 F. Supp. 2d 1297, 1308 (D. Ga. 2004) (citing *Sierra Club v. Public Serv. Co.*, 894 F. Supp. 1455, 1460 (D. Colo. 1995)). Title V permits must contain monitoring and reporting requirements to allow citizen enforcement, in addition to the ability of State and Federal Regulators' ability to enforce the Title V permits). The USEPA has provided examples of permit conditions that are not enforceable as a practical matter in a letter to the Ohio Environmental Protection Agency ("OEPA") setting out deficiencies in Ohio's Title V program. In that letter, EPA explained that, "In addition to implementing appropriate compliance methods, the monitoring, recordkeeping, and reporting requirements must be written in sufficient detail to allow *no room for interpretation or ambiguity in meaning. Requirements that are imprecise or unclear make compliance assurance impossible*" *(See* Letter from Bharat Mathur, USEPA, Region 5, to Robert F. Hodanbosi, Ohio Environmental Protection Agency, November 21, 2001, Commenter's Exhibit 131.)

Similarly, USEPA policy explains that for a permit condition to be enforceable, the permit must leave no doubt as to exactly what the facility must do to comply with the condition. *Region 9 Guidelines*, at 111-55. "A permit is enforceable as a practical matter (or practically enforceable) if permit conditions establish a clear legal obligation for the source [and] allow compliance to be verified. Providing the source with clear information goes beyond identifying the applicable requirement. It is also important that permit conditions be unambiguous and do not contain language which may

(1) A technically-accurate limitation and the source subject to the limitation; (2) the time period for the limitation (hourly, daily, monthly, and annual limits such as rolling annual limits); and (3) the method to determine compliance including appropriate monitoring, recordkeeping, and reporting.
73 FR 1570, 1573 (January 9, 2008).

This comment correctly observes that the CAA requires a permit's conditions be enforceable as a "practical matter." The comment also cites to the appropriate criteria that a permit term must contain in order to be considered practically enforceable: "(1) a technically accurate limitation and the portions of the source subject to the limitation; (2) the time period for the limitation (hourly, daily, monthly, annually); and (3) the method to determine compliance including appropriate monitoring, record keeping and reporting." ***See, Guidance on Enforceability*** **at 6. In general, a permit limit is specific and technically accurate if "a source is fairly on notice as to the standard it must meet."** ***Id.*** **at 8. The averaging time for a limit is practically enforceable if it "readily allow[s] for determination of compliance."** ***Id.*** **at 9. In addition, "EPA policy allows for rolling limits not to exceed 12 months or 365 days where the permitting authority finds that the limit provides an assurance that compliance can be readily determined and verified."** ***Id.*** **The method to determine compliance must "state the monitoring requirements, record keeping requirements, reporting requirements, and test methods as appropriate for each potential to emit limitation."** ***Id.*** **at 8.**

USEPA has also instructed that in evaluating the practical enforceability of a permit term, the permit should be considered as a whole and in the appropriate context. Examining permit terms in isolation should probably be avoided, as it can overlook relevant linkages between inter-related conditions. ***See, Newmont Nevada*** **at 474 (observing that various compliance monitoring and recordkeeping requirements, when viewed together, demonstrated that the permit terms were fully enforceable).**

GENERAL ISSUES

126. Findings are not enforceable permit conditions. In issuing PSD permits, state agencies and applicants must identify a host of parameters, including the sulfur and ash content of the fuel, to determine emission limitations, compliance with PSD increments and NAAQS. As is always the case, all of the parameters used in making these assessments do not necessarily become part of the federally enforceable terms of the facility's permits. It is key that essential parameters that will ultimately impact the facility's ability to emit at a certain level

---

intentionally or unintentionally prevent enforcement." The "practical enforceability" requirement is necessary "to assure the public's and EPA's ability to enforce the title V permit is maintained, and to clarify for the title V source its obligations under the permit." III-56. Citizens do not have the powers at their disposal that agencies have (i.e., the power to conduct an inspection, the power to require the submittal of records or documents by the Permittee, or the power to reopen a permit). As a result, the permit must be self-contained (include all terms, definitions and conditions that are necessary to enforce the permit) and must be clear in order to be practically enforceable. *See* III-57 to III-62. USEPA, Region 9, Title V Permit Review Guidelines, Practical Enforceability, September 9, 1999. Also referred to "Region 9 Guidelines" (Commenter's Exhibit 147)hereafter

or comply with NAAQS and PSD increments must be included in the enforceable permit conditions, in order for those provisions to be practically enforceable.

While most of the Draft Permit for the TEC would contain enforceable conditions (*see, e.g.*, Section 3, Source Wide Permit Conditions, Section 4, Unit Specific Conditions for Specific Emission Units), not all of the provision in the permit are enforceable conditions. Notably, Section 1, the Findings, are probably not enforceable permit conditions as it is a narrative description by the IEPA about why it is issuing this permit. Some key assumptions that would impact the permitted emissions of the TEC are contained only in this section. IEPA should revise the permit to include these parameters in the permit conditions.

The Draft Permit includes nine "Findings for the Revised Permit." These include findings on the amount of syngas that will be produced (64 million standard cubic feet), the power block nominal net electrical out (602 MW), and the design coal supply for the plant. In particular, Finding 3(c) in the Draft Permit states, for example:

> The design coal supply for the plant would be Illinois Basin coal nominally containing 4.4 percent sulfur by weight and 11,300 Btu per pound as received at the plant. The design feed rate of coal to the gasification block would be 212 tons of coal per hour.

This is not a permit condition but rather a "finding." There is not a corresponding permit condition that limits the TEC to using the coal that was used as the basis of the emission estimates, which in turn were used to demonstrate compliance with NAAQS and to determine major source status. The HAP emission calculations, for example, were based on a specific Illinois Basin coal, from the Herrin seam.[624] Other coals would have different amounts of HAPs. Information found elsewhere shows that the use of Herrin seam coal is by no means a given but that the TEC also considers using coal from the Springfield seam.[625]

Similarly, the SO_2 emissions were based on a coal containing 3.75% sulfur, but the subject finding indicates coal nominally containing 4.4% sulfur would be used. This would significantly increase SO_2 emissions and cause violations of the 1-hr SO_2 NAAQS. Finally, as discussed below, the Permit does not require any monitoring to discover violations of emission limits established with the coal assumed in the Application. Thus, if CCG chooses to use a higher sulfur coal, or a coal containing more HAPs, it would not be discovered.

Because each type of coal or coal blend can have different effects on the TEC's emissions and hence air quality impacts and major source status of the TEC, there must be an enforceable permit condition limiting the amount of sulfur and HAPs in the coal feed or else CCG's emission estimates and proposed permit limits are meaningless.

---

[624] Ap., p. 12-2 **("...** metallic HAP emissions from raw syngas, sweet syngas, and off-spec SNG combustion in the flare were calculated based on emission factors derived from Herrin coal metals data) and Table C-22-.2, p. C- 82.

[625] Illinois Commerce Division, Taylorville Energy Center Facility Cost Report, Exhibit 6.0, Wood Mackenzie Study, The Delivered Price of Coal to the Taylorville Energy Center, p. 9; http://www.icc.illinois.gov/downloads/yublic/en/Exhibit%206.0%20-%2OWood%20Mackenzie%20Study%2OThe%20Delivered%20Price%20oft/o2OCoal%2Oto%2Othe%20Taylorville%20Energy%20Center.pdf (Commenter's Exhibit 60).

As acknowledged by the comment, the Findings in the permit provide a brief summary of the basis of the permit and the findings by the IEPA that led to the issuance of this permit. As such the Findings are not intended to be enforceable conditions and were not prepared so as to be enforceable.

As related to the sulfur content of the coal feedstock used by the plant, a limit is not needed on this parameter. As discussed elsewhere, the sulfur content of the coal is not a factor on the emissions of the gasification block during normal operation. For these periods and for periods of startup and shutdown, when sulfur content does play a role in SO_2 emissions, the rates of SO_2 emissions are explicitly limited. This comment does not show that these limits are not practically enforceable. Moreover, the simple fact that a particular parameter may be a factor in emissions does not dictate that such factor must also be separately limited, along with limits on emissions.

127. The assumptions used in emission calculations are not made enforceable. The Application estimated emissions from many sources, including the flares; feedstock and bulk material handling, drying and storage; equipment components; cooling towers; and roadways and other open areas using a wide range of assumptions, including throughputs, silt content, number and type of vehicles, miles traveled, areas, concentrations, flow rates, and control efficiencies, etc. The resulting emissions were used in air dispersion models to demonstrate compliance with PSD increments and NAAQS.

However, the Draft Permit does not require any actual monitoring to determine compliance with these emission limits, arguing monitoring is not feasible and thus a work practice standard applies. However, the variables that were used to estimate the emissions can be limited to those assumed in the calculations and measured. Silt content, for example, a key input to all of the material handling emissions, is easily measured using the method in AP-42. The throughput for the various operations can be limited in the permit and recorded. The resulting data can be used to estimate emissions using the same procedures used in the Application.

The comment is incorrect that other parameters used in calculations for emissions of fugitive particulate, as contained in the application to develop emission data, must then become limits in the permit. In essence, the comment asserts that "potential to emit" or PTE calculations themselves should be made enforceable. Nothing in the Clean Air Act or the PSD program requires that the variables and assumptions behind PTE calculations must be enforceable. Rather, if a physical or operational <u>limitation</u> is considered in estimating PTE, it is that physical or operational limitation or its effect on emissions that may need to be made enforceable as a practical matter. Where emissions are limited by the permit, the concept of "worst case" or "enforceable" PTE calculations has no bearing. The enforceable permit limits establish the PTE in those instances. *See In re Knauf Fiber Glass GMBH*, 8 E.A.D. 121, 159 (EAB 1999) (denying review of petition seeking estimates of emissions as a result of malfunctions because the permit included emissions limits that applied during such periods); *Louisiana Pacific Corp.* 682 F. Supp at 1159.

The permit limits the overall operation of the plant by setting a limit on the overall amount of feedstock fed to the gasification block (Condition 4.1.5-1). This will directly constrain the amount of feedstock handled by coal handling operations as well as other aspects of plant operation. As discussed elsewhere in this response, the permit contains practically enforceable emission limits for the flare, equipment components, cooling towers, roadways and material handling units, including physical and operational limitations. *See* Condition 4.1.2-1.d.ii. (Flare emissions limits); Condition 4.9.2.d. (limits on component leaks); Condition 4.4.6 (Cooling tower emissions limits); (Condition 4.11.6 (PM emissions limits from on roadways). The comment incorrectly asserts that no actual monitoring to demonstrate compliance with these limits is required. On the contrary, for each of these emission units, the permit sets forth multiple operational monitoring, recordkeeping, and reporting requirements that collectively ensure continuous compliance with the associated limits.[626]

The permit imposes similarly comprehensive measurements, monitoring and recordkeeping requirements across all units. These terms and conditions are, by themselves, entirely sufficient to ensure that the associated emissions limits are practically enforceable. It is not necessary to set additional limits on particular parameters to provide practical enforceability. To do so would be contrary to providing the TEC with reasonable and appropriate flexibility and ability to comply with the applicable limits that are set. For example, if measurement of silt loadings show loadings that are different than those used in the emission calculations (as is to certainly be expected given the nature of these calculations for a proposed plant), CCG would have to develop or refine its practices for control of fugitive dust to appropriately address the actual levels of silt that are present.

128. The IEPA cannot issue the permit because it does not incorporate malfunction, startup/shutdown, and quality control plans into the permit which the agency relied upon to determine that the source will meet applicable requirements or provide these plans for public comment. The Draft Permit would require that a number of plans be developed in the future to satisfy BACT. These include Startup, Shutdown, and Malfunction Plan for emission units (Conditions 4.1.2-1.c and 4.1.5-2); Flare Minimization Plan (Condition 4.1.5-3); a Feedstock Management Plan (Condition 4.1.5-4); a Startup, Shutdown and Malfunction Plan for the Power Block (Condition 4.2.5-2); a Fugitive Dust Control Program for material handling emissions (Condition 4.3.5(e)); Haul Road Operating Plan (Condition 4.11.5). These plans will be developed in the future, outside of the PSD review process which will preclude public review.

Throughout the permit, IEPA relies on the SSM, minimization, and emission control plans to assure compliance with applicable standards. IEPA does not merely require the plans to be submitted, but relies on the plans as the basis for finding that the plant will comply with applicable requirements and to define terms in the permit. Because IEPA is relying on these plans to ensure compliance and to define permit terms, the Plans must be provided in the

[626] **For instance, the Permit requires continuous operating monitoring of the process gas flow rates to the flare, as well as a broader, comprehensive flare monitoring plan (Condition 4.1.8-2) and detailed recordkeeping during the flaring of process gases (Condition 4.1.10-2). As for fugitive PM emissions from roadways, despite the suggestion in the comment, the permit *does* in fact require CCG to measure silt loadings on roadways (Condition 4.11.8), in addition to keeping records of other operating factors and control measures (Condition 4.11.9).**

application. 40 CFR 70.5(a)(2) (a complete application must contain sufficient information to determine all applicable requirements), 40 CFR 70.5(c) (application cannot "omit information needed to determine the applicability of or impose, any applicable requirement..."), 40 CFR 70.5(c)(3)(vi) (application must include any "work practice standards"). The plans were not included with the application, or the public review documents. The public had no opportunity to review the plans to determine whether they were sufficient. This is unlawful.

In addition, because compliance with the plans constitutes a Permit requirement, the plans must be subject to public notice and comment. The public cannot comment on the sufficiency of the Permit, which incorporate, reference, or otherwise rely on the plans, when the plans were not part of the permit record and will not even be created until after the permit is issued. 40 CFR 70.7(h); *see e.g., In re RockGen Energy Center,* 8 E.A.D. at 553-54 (remanding permit requirement for a startup/shutdown plan that was not subject to public notice and review); *Waterkeeper Alliance v. EPA,* 399 F.3d 486, 503-04 (2nd Cir. 2005) (invalidating EPA regulation that allowed Nutrient Management Plans to be submitted after public comment and after a NPDES permit was issued).

The various plans addressed by this comment do not have to be prepared and available at this time, as claimed by this comment. This is a construction permit based on specifications and preliminary data that are available for the plant, as summarized in the application. The permit requires certain plans that are to be developed in the future, in conjunction with the further detailed design of the plant and with the actual operation of the plant. In this regard, the circumstances are significantly different than those associated with operating permits, which deal with operating facilities for which the required plans may be prepared. As such, the provisions of 40 CFR Part 70 that are cited by this comment, have no relevance to this permit.

In addition, unlike the *Rockgen* case, the permit for the TEC does not contain a blanket exemption for SSM events. The permit contains numeric emissions limits and associated specific monitoring and recordkeeping requirements, and requires development and implementation of an SSM plan. Additionally, the provisions for flaring minimization and the elements to be covered in the SSM plan are clearly set forth in the permit and thus were available for public comment. Conditions 4.1.5-2 and 4.2.5-2 (SSM Plans); and Condition 4.1.5-3 (Flare Minimization Plan). Therefore, these plans did not need to be included as part of the application and availability for public comment was not necessary. *See In re Indeck-Niles L.L.C.*, PSD Appeal No. 02-03 (EAB Mar. 11, 2002).

The comment's reliance on *Waterkeeper Alliance v. EPA*, 399 F.3d 486, 503-04 (2nd Cir. 2005) is misplaced. The controversy in that case occurred within the distinct regulatory context of National Pollution Discharge Elimination System (NPDES) permitting under the Clean Water Act. Unlike a pre-construction PSD permit, NPDES permits are not required before a new source is built, but rather before any new discharges occur. *See* 33 U.S.C. §§ 1311(a), 1342. Thus the same practical constraints necessitating post-permit issuance of the plans here -- constraints based on the lack of design and operational data -- do not apply in the case of an NPDES permit.

Moreover, the plans at issue in *Waterkeeper Alliance themselves* constituted the effluent limits that would be required and, as such, were expressly required by statute to be included in the permit.[627] By contrast, the plans identified in this comment are meant to serve as compliance assurance mechanisms and a means to further reduce emissions beyond the prescribed limits, not stand alone emissions limitations.

The appropriateness of the timing of the submittal of the SSM plan (Conditions 4.1.5-2 and 4.2.5-2) is addressed above. The same reasoning applies to each of the additional plans mentioned by this comment. Because this is a *pre*-construction permit, issued at a time in which significant final design details relative to these plans have not been finalized, submission of these sorts of plans after issuance of the permit is both appropriate and a practical necessity. The plans identified by the comment merely define specific monitoring and/or testing procedures that simply cannot be known or determined in advance of actual construction and operation of the plant.

While the plans themselves are not included, the permit does set forth the purpose and scope of each of these plans. (Conditions 4.1.5-2 and 4.1.5-3). Failure to make these plans available for public comment with the permit does not violate any applicable notice requirement. The EAB has explicitly cautioned against making it difficult to include in permits provisions such as the Flare Monitoring Plan (FMP):

> **[T]he Board is concerned that unnecessarily making implementation of the FMP unduly burdensome might discourage inclusion of such valuable provisions, or at least delay implementation of the benefits of the analyses contemplated by such provisions, to the ultimate detriment of air quality, and contrary to the purposes of the PSD program.[628]**

As for the Fugitive Coal Dust Control Program (Condition 4.3.5.e), this plan is expressly required by NSPS Subpart Y to be submitted prior to *startup*, not prior to permit issuance. 40 CFR 60.254(c)(4). By definition, the NSPS is enforceable as a practical matter. USEPA's decision regarding the timing of submittal of this plan is reasonable and appropriate because the actual requirements imposed by the plan cannot be determined until the design of the subject emission units has been finalized, as is the case with the other plans required by the permit.

FLARE CONDITIONS ARE NOT ENFORCEABLE

129. Flare Sulfur Conversion Efficiency Not Enforceable

The SO_2 flare emission calculations assume that 98% of the sulfur in the flared gases is converted to SO_2. If a larger amount of the sulfur were converted to SO_2, the 1-hour SO_2 NAAQS could be exceeded. The Draft Permit does not contain any limit on the sulfur to SO_2 conversion efficiency of the flare nor any method to determine if it is met.

---

[627] **The Clean Water Act requires that all applicable effluent limitations be included in each NPDES permit. *See* 33 U.S.C. §§ 1311(a), 1311(b), 1342(a). The rule at issue in *Waterkeeper Alliance* established *non-numerical* effluent limitations in the form of best management practices. *See* 40 C.F.R. § 412.4. Among these best management practices was the requirement that Permittees "develop and implement a nutrient management plan" that, *inter alia,* sets application rates that minimize pollutant discharges. *See* 40 CFR 412.4(c)(1).**

[628] ***In re Power Holdings of Illinois, LLC,* PSD Appeal No. 09-04, slip op. at 13-16 (EAB Aug. 23, 2010)**

As discussed elsewhere, the sulfur conversion efficiency used for the flare SO_2 emission calculations (98%) is consistent with USEPA recommendations for calculating SO_2 emissions from refinery flares. Also, the hourly SO_2 emissions from the flare would only increase by a small amount (i.e., an increase from 9,036 lb/hr to 9,220 lb/hr) if the conversion efficiency were increased to 100% as the comment suggests is appropriate. If this relatively small increase in hourly SO_2 emissions from the flare were included in an updated 1-hr SO_2 NAAQS modeling run, the conclusions of the 1-hr SO_2 NAAQS analysis would not change. The modeled emission rate was based on worst-case coal sulfur content and other conservative assumptions, including modeling setup, that could be refined, as necessary. For example, CCG assumed that the worst-case flare, SRU thermal oxidizer, and AGR vent hourly SO_2 emissions during a cold plant startup all occur during the same hour when in actuality the highest SO_2 emissions from the SRU thermal oxidizer and AGR vent will not occur until after the syngas has been fed forward into the process and no raw syngas flaring is occurring. Applying a schedule to the modeled emission rates for the flare, AGR vent oxidizer, and SRU thermal oxidizer in the 1-hr SO_2 NAAQS modeling which more closely matches the actual emissions expected during a cold plant startup would significantly reduce the modeled impacts, such that a higher emission rate from the flare could be accommodated without causing an exceedance of the NAAQS.

As also discussed elsewhere, establishing a "no more than" 98% sulfur conversion efficiency limit in the permit for the flare would be at cross-purposes with design and operation to achieve "at least" 98% efficiency for control of CO and VOM.

130. The destruction efficiencies of the flare for different pollutants are not enforceable. The emission calculations assume destruction and removal efficiencies of at least 98% for CO and VOM and at least 99% for methanol and methane. The Draft Permit establishes these as limits. Condition 4.1.2-la(v). However, it does not require any method to assure these removal efficiencies are achieved in practice. Conditions 4.1.7-1 and 4.1.8-2.

These can be demonstrated using a combination of three methods. First, the Permit should require that the flare vendor supply a guarantee for the subject efficiencies and supply the guarantee to the IEPA. Second, the Permit should be modified to require video monitoring of the flare, as currently required in SJVAPCD Rule 4311 and that actions be taken to improve combustion efficiency when anomalous conditions are observed, e.g., flame detachment from the flare stack, soot, etc. Third, it is feasible to measure the combustion efficiency using various remote sensing methods such as passive FTIR, which has been required by the EPA in other situations.[629]

CCG must demonstrate compliance with the flare destruction and removal efficiencies for CO, VOM, methanol, and methane established in Condition 4.1.2-1(a)(v) by conducting the flare design analysis required by Conditions 4.1.7-1(a) and (b) (in accordance with the relevant requirements of 40 CFR 60.18). The initial flare design analysis requirements in 40 CFR 60.18 for NSPS affected flares are equivalent to the

[629] Marathon Petroleum Company, Performance Test of a Steam-Assisted Elevated Flare with Passive FTIR, Final Report, May 2010, (Commenter's Exhibit 133; Thomas R. Blackwood, An Evaluation of Flare Combustion Efficiency Using Open-Path Fourier Transform Infrared Technology, *J. Air & Waste Manage. Assoc.*, v. 50, Oct. 2000, pp. 1714-1722, (Commenter's Exhibit 134).

similar requirements for NESHAP affected flares in 40 CFR 63.11. Therefore, the approach used in the permit to evaluate compliance with flare efficiency requirements is consistent with how USEPA regulates affected flares at facilities subject to NSPS or NESHAP rules.

The flare requirements in 40 CFR 60.18 also establish minimum heating value and maximum exit velocity requirements that are intended to ensure the process gas fed to a flare will be combusted at an efficiency equivalent to the design DRE. Under certain operating scenarios, the flare at the TEC will have a heating value below the minimum design requirements in 40 CFR 60.18 and an exit velocity above the maximum design requirements in 40 CFR 60.18. The inability of syngas to meet the process gas requirements of 40 CFR 60.18 has been documented in the literature, but even when the minimum heat content and related exit velocity requirements in 40 CFR 60.18 are not met, syngas flares are expected to achieve in excess of 98% efficiency for CO and VOM.[630] Recognizing this aspect of syngas flares, the permit establishes an alternative compliance method for the TEC's flare, which is consistent with the approach for addressing flare operation in the permit for the similar Kentucky NewGas SNG production facility.[631] When syngas is sent to the flare and the exit velocity or gas heat content is not expected to meet the relevant requirements in 40 CFR 60.18, Condition 4.1.7-1(c) requires visual observation of the flare to evaluate the condition(s) of the flare flame, including the nature of the features of the flame that would indicate stable and unstable combustion, such as burn-out or lift-off (i.e., separation(s) between the flare tip and parts of the flame). Since stable flames and high efficiency are linked as discussed in the USEPA literature used to develop the 40 CFR 60.18 requirements for high-hydrogen flares, observing a stable flame during periods of syngas combustion when the requirements of 40 CFR 60.18 cannot be met will ensure that the flare is operating at or above its design efficiency.[632]

The comment suggests that three additional permit requirements should be added to make the flare efficiency requirements in Condition 4.1.2-1(a)(v) enforceable. First, the permit should require a vendor guarantee which should be supplied to the IEPA. Second, permit should include video monitoring requirements consistent with the requirements of SJVAPCD Rule 4311. Finally, the combustion efficiency of the flare should be tested using a remote sensing method such as passive FTIR. These additional requirements are not necessary to ensure the flare efficiency requirements are achieved in practice.

Flare vendors do not typically provide guarantees such as suggested by the comment, as there would be no way to determine if the guarantee was achieved. Flare vendors do, however, evaluate the composition, heating value, flow, temperature, pressure, and other relevant design data for the process gas streams expected to be routed to the flare

---

[630] **John Zink Company, An Experimental Analysis of Flame Stability of Open Air Diffusion Flames, March 20, 1995 (provided as Attachment B to the December 28, 2011 draft permit comment letter submitted by Larry Carlson, CCG to Dean Studer, IEPA).**

[631] **Kentucky Division for Air Quality, Final Air Quality Permit Issued Under 401 KAR 52:020 for Kentucky Syngas, LLC, September 24, 2010, p. 12, available at http://dep.gateway.ky.gov/eSearch/**

[632] **USEPA, Basis and Purpose Document on Specifications for Hydrogen-Fueled Flares, March 1998, available at http://www.epa.gov/ttn/caaa/t1/reports/b_p.pdf (provided as Attachment C to the December 28, 2011 draft permit comment letter submitted by Larry Carlson, CCG to Dean Studer, IEPA).**

to determine the best flare header and flare tip designs for consistently high efficiency at or above the level assumed in the development of the flare BACT limits (refer to John Zink flare selection criteria cited elsewhere). Once the flare system is designed based on the final design of the plant, flare vendors also typically establish operating parameter ranges that must be met in order to achieve the design performance. CCG is required to operate the flare in accordance with good air pollution control practices (Condition 3.6) and to maintain a file containing the design flare efficiency for CO, VOM, methanol and methane with supporting documentation [Condition 4.1.10-2(a)]. The supporting documentation used to justify the design efficiency for the flare will include all information provided by the flare vendor that is relevant for assessing flare efficiency including any ranges for operating parameters or work practices that are recommended.

This comment mischaracterizes the video monitoring requirements of SJVAPCD Rule 4311. Section 6.10 of the Rule 4311 requires the following for flare video monitoring:[633]

> **Effective on and after July 1, 2011, the operator of a petroleum refinery flare shall install and maintain equipment that records a real-time digital image of the flare and flame at a frame rate of no less than one frame per minute. The recorded image of the flare shall be of sufficient size, contrast, and resolution to be readily apparent in the overall image or frame. The image shall include an embedded date and time stamp. The equipment shall archive the images for each 24-hour period. In lieu of video monitoring the operator may use an alternative monitoring method that provides data to verify date, time, vent gas flow, and duration of flaring events.**

As the last sentence indicates, video monitoring is one alternative, but refineries have the option to use other alternative monitoring to verify the date, time, vent gas flow, and duration of flaring events. CCG would satisfy SJVAPCD Rule 4311 without being required to install a video monitoring system based on Condition 4.1.8-2(a), which requires CCG to install, operate, and maintain continuous monitoring systems to determine the total flow of process gas sent to the flare and the date, time and duration of each occurrence of venting of process gas to the flare. A video monitoring system for the flare also is not necessary based on the visible emissions observation requirements in the permit. Condition 4.1.10-2(b)(iv) requires CCG to keep records of any visible emissions during each event when process gas is flared to demonstrate compliance with the requirements of 40 CFR 60.18(c)(1) (i.e., no visible emissions as determined by USEPA Method 22, except for periods not to exceed a total of 5 minutes during any 2 consecutive hours). In addition, when syngas is flared and CCG does not expect to meet the requirements of 40 CFR 60.18, Condition 4.1.7-1(c) also requires CCG to conduct visual observations of the flare flame stability to assess combustion efficiency. The visual observation requirements in the permit serve the same purpose as video monitoring to verify the flare is operating properly during each flaring event.

---

[633] **SJVAPCD, Current District Rules and Regulations: Rule 4311 for Flares, available at http://www.valleyair.org/rules/1ruleslist.htm.**

Open path emissions measurement technologies such as passive Fourier Transform Infrared (OP-FTIR) spectroscopy are in the research and development phase, and no USEPA approved flare test methods using this technology have been promulgated or even proposed for regulatory use.[634] The Marathon steam-assisted flare study provided in Commenter's Exhibit 133, whose main objective was to better understand the impact of steam on flaring, acknowledges that passive OP-FTIR "is a new tool that has not yet been blind validated against extractive sampling results," and therefore, "additional research is needed to characterize the instrument's overall precision and bias."[635] Extractive FTIR techniques for the measurement of various organic and inorganic compound emissions from various types of sources have been established by USEPA as reference methods (refer to Methods 318, 320, and 321), but these extractive techniques cannot be applied to flares because of the difficulty and danger posed by attempting to extract emissions from an open flare flame.[636] The statements about the current status of passive OP-FTIR in the Marathon study suggest additional validation against the more accurate, USEPA accepted extractive FTIR techniques in a laboratory setting is necessary before passive OP-FTIR can be deployed as a regulatory test method for assessing the combustion efficiency of an industrial flare. Without an approved test method for passive OP-FTIR, the permit appropriately relies on other available monitoring techniques to demonstrate the flare is properly operating at all times and is achieving its design DRE.

131. The results of the BACT analysis for the flare are not required as enforceable conditions. The BACT analysis in the Application identified a specific operating procedure to reduce emissions during a cold plant startup by 60%, from 170,000 lb/event to 72,000 lb/event. This procedure involves shifting raw syngas forward into the control system as quickly as possible.[637] The planned startup and shutdown emission calculations assumed this procedure is used. *See* Comments infra. The IEPA Project Summary does not mention it, and it is not required in the Draft Permit to satisfy BACT. Condition 4.1.2-1. Thus, the BACT determination is not enforceable.

The maximum hourly SO_2 emission rate set for the flare (Condition 4. 1.6.b) was calculated based on this BACT assumption. However, as discussed infra, the Draft Permit does not contain adequate monitoring to determine if this emission rate is achieved. Therefore, the maximum hourly emission rates using in the PSD increment and NAAQS modeling are not enforceable as a practical matter.

As discussed elsewhere, the comment incorrectly concludes that the permit would not require implementation of the cold plant startup procedure conceptually described in

---

[634] **The primary repository of publicly available information from USEPA regarding this technology is USEPA's Office of Solid Waste and Emergency Response (OSWER) Technology Innovation Program. Its *Measurement and Monitoring Technologies for the 21st Century* (21M^2) program website clearly states that the program's mission is to "research and inventory the state of the art for advanced monitoring technologies" for future commercial and regulatory deployment. EPA's Office of Solid Waste and Emergency Response, Technology Innovation Program, *Measurement and Monitoring Technologies for the 21st* Century (21M^2), September 11, 2006. (http://www.clu-in.org/programs/21m2/strategy.cfm). OP-FTIR is listed among other open path technologies for future development along with Differential Absorption Light Detection and Ranging (DIAL), ultra-violet differential optical absorption spectra (UV-DOAS), Raman spectroscopy, and tunable diode lasers (TDLs).**

[635] **Commenter's Exhibit 133, pp. 1-2 and 1-4.**

[636] **USEPA, Technology Transfer Network, Emissions Measurement Center, Monitoring, FTIR Technology, available at http://www.epa.gov/ttn/emc/ftir.html**

[637] Ap., p. 6-6.

the application. CCG has developed preliminary gasification block startup and shutdown methodologies that were applied in the material balances used to derive the data for potential annual SO_2 emissions from the flare and the flare SO_2 BACT limits. Once the final design of the plant is completed, CCG will either have to develop standard operating procedures that include these proposed methodologies directly or alternative procedures that are at least as effective at minimizing emission as the methodologies envisioned when establishing the flare SO_2 BACT limits. Without taking measures to ensure that the key steps of the preliminary cold plant startup methodology envisioned in the application are implemented in practice (or developing an equally effective methodology in terms of minimizing flare emissions), CCG would jeopardize its ability to comply with the annual flare SO_2 emission limit in the permit.

The maximum hourly SO_2 emission limit for the flare was not calculated based on the 60% control described on page 6-6 of Volume 1 of the Application for the "feed forward" cold plant startup procedure. The hourly SO_2 emission limit for the flare does not take credit for any SO_2 emissions control offered by the syngas processing train. As discussed elsewhere, this emission rate was derived based on a coal throughput rate of 51.2 ton/hr on a dry basis, a coal sulfur content of 4.41%, and the assumption that all raw syngas produced by the gasifier being started is routed to the flare without benefit of any control offered by the syngas processing train. The continuous flow rate and sulfur content monitoring requirements for the flare in Condition 4.1.8-2(a) and 4.1.9(b) will ensure a complete record of the sulfur flow rate to the flare during all hours when process gas is vented to the flare. This operational monitoring will allow for a real-time evaluation of compliance with the hourly SO_2 emission limit, and thus, makes the hourly flare SO_2 BACT limit enforceable.

132. The hourly limit for SO_2 emissions of the flare is not enforceable. Condition 4.1.6(b) of the Draft Permit would hourly limits for the SO_2 emissions of the flare that are not enforceable. The permit would set a limit of 9,036 lb/hr on SO_2 emissions from the flare. This value was calculated from material balances and assumptions, such as sulfur content and duration of raw syngas flaring, which are not disclosed in the record. Exceedances of this limit would never be discovered because the permit does not require adequate testing. First, Condition 4.1.8-2(a) of the Draft Permit requires CEMS to measure total flow of process gas sent to the flare and the H_2S and CO content of this gas. This is not enough information to determine the 1-hour SO_2 emission rate. The SO_2 emissions from the flare arise from the combustion of two sulfur containing gases, H_2S and COS. The Permit does not require monitoring of COS, which excludes about 13% of the SO_2.
Second, the Draft Permit is silent on what one does with the measurements of flow rate and H_2S to come up with an hourly SO_2 emission rate. The CEMS data must be converted to pounds per hour of SO_2 and multiplied by a conversion efficiency to yield flare SO_2 emissions. The calculations that yielded the 1-hour limit of 9,036 lb/hr assumed 98% conversion efficiency. (As noted elsewhere, the permit does not require this as a limit.) CEMS measurements alone are not adequate to determine hourly SO_2 emissions at the flare, unless it is assumed that 100% of the sulfur in the gases sent to flare are converted to SO_2. This is the common assumption, but here, the calculations that led to the one-hour limit of 9,036 lb/hr assumed only 98%. A higher conversion efficiency would result in violations of NAAQS. Thus, the Draft Permit would not assure compliance with the 1-hour SO_2 limit as a

significant component of SO_2 is omitted from monitoring, no method is provided for making the calculation, and no limit on sulfur to SO_2 conversion efficiency is contained in the Permit. Thus, exceedances of the limit would never be discovered and violations of the 1-hour SO_2 NAAQS would go undiscovered.

The assumptions used to derive the hourly flare SO_2 BACT limit do not need to be addressed in the permit because the permit contains adequate monitoring requirements for demonstrating compliance with this limit on a continuous basis. The comment is incorrect that the permit does not require "monitoring" of the COS content of process gases routed to the flare and it has not correctly calculated the percentage of flare SO_2 emissions that are attributable to the COS in the process gas. Condition 4.1.9(b) requires CCG to sample and analyze raw syngas, sour syngas, sweet syngas, and SNG for COS content, and Condition 4.1.9(d) requires CCG to sample and analyze the various gas streams that could be vented to the flare for sulfur content (which would include COS). These sampling results must be used in conjunction with the continuous H_2S content monitoring to determine the SO_2 emissions from the flare on a continuous basis. As discussed elsewhere, approximately 93 - 98% of the sulfur in syngas is H_2S with only 2 - 7% being COS.[638] This relatively narrow range of COS content in raw syngas and the kinetics of the chemical reactions which determine the relative ratio of H_2S to COS content in syngas suggest that the COS content will be a relatively constant ratio of the H_2S content. Therefore, the total sulfur content of the process gas routed to the flare can be calculated from the H_2S content measured by the continuous monitoring system and the ratio of COS to H_2S in the process gas determined based on process gas sampling.[639]

The comment also suggests the permit should include a prescriptive recordkeeping requirement describing how the SO_2 emissions from the flare will be calculated based on data from the flow rate and H_2S content continuous monitoring system. As discussed elsewhere, this type of detailed permit requirement describing how actual emissions should be calculated is not appropriate for the TEC. The data that will be used in the actual flare emission calculations is not static, like a reference emission factor, and may shift based on actual operation of the plant. While the permit does not specify the exact calculation methodology for determining the SO_2 emission rate from the flare, Condition 4.1.10-2 does require CCG to record, for each flaring event, the amount of H_2S contained in the gas sent to the flare and the amount of SO_2 emitted, pounds/event, with supporting calculations. Furthermore, Condition 4.1.10-2(b)(i) requires CCG to maintain a file containing the COS emission factor for the flare (or more likely the constant COS to H_2S ratio) with supporting calculations. Finally, Conditions 4.1.10-2(b)(ii) and (iii) require CCG to record the daily, monthly, and annual (i.e., 12-month rolling) SO_2 emissions from the flare. With several flare SO_2 emissions recordkeeping requirements in the permit, any exceedances of the hourly

[638] *See, e.g.*, Power Holdings of Illinois, LLC, Flare Emissions - Evaluation, November 5, 2008, p. 3 ("When going thru the Flare:... H_2S and COS all go to SO_2."), (Commenter's Exhibit 1)

[639] **As shown in Table C-3.9 of Appendix C to Volume 1 of the Application, the molar ratio of COS to total sulfur in the process gas routed to the flare during cold plant startups, total plant shutdowns, single gasifier startups, and single gasifier shutdown ranges from 8.2% to 8.35% on a maximum hourly basis and from 8.23% to 8.83% on a per event basis. The 13% value referenced by the comment is incorrect. The relatively constant ratio of COS to total sulfur presented in Table C-3.9 on both a maximum hourly and per event basis further demonstrates the adequacy of only continuously monitoring H_2S and deriving the total sulfur content (i.e., H_2S plus COS) based on the ratio of COS to H_2S in the process gas routed to the flare.**

SO_2 flare BACT limit would be identified almost immediately and would trigger the deviation reporting requirements in the permit (refer to Condition 4.1.11-1).

133. The hourly limits for emissions of pollutants other than SO_2 from the flare are not enforceable. While Condition 4.1.6(b) of the Draft Permit sets hourly limits on VOM and PM emissions, the permit would not require any routine monitoring of these pollutants in gases sent to the flare nor any indication of how compliance with these limits would be determined. The Draft Permit does require that a file be maintained that contains emission factors used to calculate emissions (Condition 4.1.10-2), but no method on how these emission factors would be used to determine compliance with maximum annual limits. Thus, these annual limits are unenforceable.

The monitoring requirements for the VOM and PM emissions from the flare are appropriate considering the low VOM and PM emissions from the flare (i.e., 1.14 tpy and 2.95 tpy, respectively). As shown in Table C-3.10 of Appendix C to Volume 1 of the Application, the only compounds considered to be VOM found in measurable quantities in the process gas routed to the flare are COS, HCN,[640] and methanol.[641] Condition 4.1.9(b) requires sampling and analysis of raw syngas, sour syngas, and SNG for VOM content which will include COS, HCN, and methanol. In addition, Condition 4.1.9(d) requires CCG to sample and analyze the various gas streams that could be vented to the flare for VOM content. Beyond these initial sampling requirements, other provisions of the permit can be used to determine the VOM content of the process gas routed to the flare on an ongoing basis.

Condition 4.1.10-2(c)(i) requires CCG to maintain a file with all HAP emission factors used in the emission calculations for the flare with supporting documentation.

To demonstrate compliance with VOM limits applicable to the flare, CCG must implement the previously mentioned actual emission calculation methodologies and maintain records of the amount of VOM contained in the gas sent to the flare and the amount of VOM emitted from the flare (in unit of pounds/event, with supporting calculations) as required by Condition 4.1.10-2(b)(vi). Based on the flare monitoring, recordkeeping, and reporting requirements specifically established to address VOM emissions, the hourly and annual flare VOM BACT limits are enforceable.

---

[640] **HCN is commonly considered an inorganic compound from an scientific standpoint, but the relevant definition of VOC, 40 CFR 51.100, includes any compound of carbon with a list of exceptions that does not include HCN. Based on this definition, any compound containing carbon (other than CO, CO_2, and CH_4) was conservatively assumed to be part of VOM when quantifying emissions from the flare.**

[641] **As discussed previously, the relatively constant ratio of COS to H_2S expected to be present in the process gas routed to the flare will enable CCG to estimate the COS content of the flared process gas on a continuous basis using data from the H_2S content monitor. HCN should only be present in measurable quantities in the raw and sour syngas because it is water soluble so high removal efficiency will occur during routine syngas processing. The HCN emission rate in the process gas routed to the flare during cold plant startups, total plant shutdowns, and single gasifier startups and shutdowns will range from 0.41 to 1.35 lb/event. Refer to Tables C-3.3 to C-3.7 of Appendix C to Volume 1 of the Application. The HCN concentration in the process gas routed to the flare during a cold plant startup on a per event basis can be calculated as follows: 0.0385 lbmol HCN/hr on average for the event (Table C-3.10) /(0.00000268 scf/hr on average for the event (Table C-3.7) / 379.5 scf/lbmol) x 1,000,000 conversion to ppm = 5.5 ppmv. Similar calculations were performed to determine the range of HCN concentrations for all flaring events on a maximum hourly and per event basis. To calculate actual emissions of HCN from the flare, the permit requires development of an emission factor based on the results from the initial raw and sour syngas sampling required by Conditions 4.1.9(b) and 4.1.9(d). Methanol is not formed in the gasifiers, so the only way it gets into the flared process gas is through direct contact with the liquid methanol fed to the AGR unit. The permit requires methanol analysis for sweet syngas and SNG routed to the flare [Condition 4.1.9(b)], and, similar to the approach for HCN emissions, development of a methanol emission factor to be used to quantify actual methanol emissions from the flare on an on-going basis.**

As discussed in Section 6.1.4 of Volume 1 of the Application, the only off-specification process gas routed to the flare that is expected to contain particulate matter is the raw syngas generated for a brief period during gasification block startups and shutdowns. This raw syngas will be treated in the raw gas treatment system for PM removal prior to being routed to the flare header, and thus, is expected to consist of very fine dust that cannot be readily removed by water scrubbing. Without available sampling or monitoring techniques that have been previously applied to measure PM in a pressurized flare header, the permit requires compliance with the flare PM BACT limits to be demonstrated by: 1) monitoring the total flow rate of raw syngas routed to the flare [Condition 4.1.8-2(a)], 2) establishing a PM emission factor for raw syngas flaring based on an estimate of the particulate loading in the raw syngas developed by Siemens from laboratory tests of their gasifier system [Condition 4.1.10-2(b)(i)], 4) calculating PM emissions based on the emission factor and raw syngas flow rate measured by the continuous flow monitor and 5) maintaining daily, monthly, and annual PM emissions records of the amount of PM emitted from the flare with supporting calculations [Condition 4.1.10-2(b)(iii)].[642] Based on this methodology, which involves a combination of continuous monitoring and reference emission factors, the flare PM BACT limits are enforceable.

134. Annual limits for emissions of the flare are unenforceable. Condition 4.1.6(b) of the Draft Permit sets annual limits on emission of SO_2, NOx, CO, VOM, PM, COS, and CO_2e from the flare in that are not enforceable. First, as explained for the hourly limits, the Permit does not require any routine monitoring of most of these pollutants in gases sent to the flare (CO and H_2S are monitored) nor any indication of how compliance with these limits would be determined. The Draft Permit does require that a file be maintained that contains emission factors used to calculate emissions of VOM, PM, and other pollutants (Condition 4.1.10-2), but no prescription for what those emission limits can be and how they might be used to determine compliance with maximum 1-hour emission limits. Thus, these limits are unenforceable. In addition, these annual limits only take effect one year after the shakedown of the gasification block is complete. This means no limits at all are in place for

[642] **USEPA's reference methods for measuring PM emissions (i.e., Methods 5, 201, and 202) are based on isokinetic extraction of exhaust gas through filtration devices and impingers to collect the PM followed by weight measurements to quantify the mass of PM present in the volume of exhaust gas sampled. The USEPA methods for measurement of PM were not developed to enable such sampling to be conducted on process lines that operate at high pressures. Rather they were developed for measurements in stacks, which are open to the atmosphere and operate at or near ambient pressure. CCG indicates that it is not aware of these measurement techniques ever being applied to a pressurized flare header to quantify PM emissions from intermittent discharges of process gases with highly varying flow rates and PM concentrations. PM CEMS have also been developed for measuring PM concentrations in the exhaust gas from sources like, hazardous waste combustors, and Portland cement kilns (refer to USEPA Performance Specification 11). USEPA, Current Knowledge of Particulate Matter (PM) Continuous Emissions Monitoring (EPA-454/R-00-039), September 2000, available at http://www.epa.gov/ttn/emc/cem/pmcemsknowfinalrep.pdf. USEPA, Performance Specification 11—Specifications and Test Procedures for Particulate Matter Continuous Emission. Monitoring Systems at Stationary Sources, available at http://www.epa.gov/ttn/emc/perfspec/ps-11.pdf. Some of these PM CEMS technologies can conduct in-situ measurements of PM concentrations using various techniques (including light scattering, beta attenuation, probe electrification, light extinction, and optical scintillation) without the need to extract and transport a gas sample for analysis. However, the use of such monitoring techniques is dependent upon measurements of PM emission using established test method, because such measurements are needed to calibrate the monitoring system. CCG is not aware of any examples of facilities measuring the particulate loading to a flare using a PM CEMs. In fact, a comprehensive survey of monitoring techniques for refinery emissions sources including flares conducted by the Canadian Council of Ministers of the Environment (CCME) concluded that the best available method for quantify PM emissions from flares is to use an emission factor. CCME, National Framework for Petroleum Refinery Emissions Reductions, available at http://www.ccme.ca/assets/pdf/nfprer_final_e.pdf. In addition, USEPA recommended the use of an emission factor approach for quantifying PM emissions from refinery flares in the *Emission Estimation Protocol for Petroleum Refineries* released with the recent information collection request (ICR). RTI International, Emission Estimation Protocol for Petroleum Refineries, Version 2.0, September 2010, available at http://www.epa.gov/ttnchie1/efpac/protocol/index.html.**

COS and CO_2e for over a year after startup, and no annual limit for SO_2, NOx, CO, VOM, and PM.

The previous discussion regarding the enforceability of the hourly flare BACT limits for SO_2, VOM, and PM applies equally to the annual flare BACT limits for NOx, CO, COS, and CO_2e.

NO_x is not present in the process gas routed to the flare and thus is only emitted from the flare as a by-product of combustion at the flare tip.[643] . Measurement methodologies are not available for quantifying NOx emissions from the open flame of a flare in routine practice, so actual NOx emissions are quantified relying on reference emission factors such as those found TCEQ's flare permitting guidance document entitled *Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers*, which.[644] ,. Compliance with the flare NOx limits will be demonstrated by: 1) monitoring the total flow rate of process gas routed to the flare [Condition 4.1.8-2(a)], 2) estimating the heat content of the process gas based on the results of initial sampling [Conditions 4.1.7-1(b), 4.1.9(b), and 4.1.9(d)], 3) estimating the ammonia content of the process gas based on material balance data, 4) calculating thermal NOx emissions based on the heat input rate of process gas to the flare, 5) calculating fuel NOx emissions based on the ammonia flow rate in the process gas routed to the flare, and 6) maintaining daily, monthly, and annual records of total NOx emissions from the flare with supporting calculations [Condition 4.1.10-2(b)(iii)].[645] The use of the emission factors in combination with site-specific data makes the annual flare NOx emission limit enforceable.

The permit requires continuous flare gas flow rate and CO content monitoring which can be used to calculate CO emissions from the flare on a continuous basis (in the same fashion as the CO CEMS will be used to quantify CO emissions from the combustion turbines). The only input needed to calculate flare CO emissions from the output of these continuous monitoring systems is the design efficiency for CO [98%, as required by Condition 4.1.2-1(a)(v)]. As previously discussed, the initial flare design analysis and other flare monitoring provisions will ensure the flare achieves its design efficiency for CO. With a continuous record of CO emissions available for the flare, the CO limits are practically enforceable.

As discussed previously, actual COS emissions will be quantified based on the process gas sampling required in Conditions 4.1.9(b) and 4.1.9(d) and the continuous H_2S content monitoring in Condition 4.1.8-2(a). The process gas sampling results will be

---

[643] **As discussed in Section 6.1.3 of the Application, the collateral NOx emissions formed by the flare include contributions from "thermal" NOx and "fuel" NOx. Thermal NOx refers to NOx formation that occurs from high temperature combustion of any combustible gas in the presence of nitrogen. Fuel NOx refers to NOx formation that results from oxidation of the already-ionized nitrogen contained in the fuel or process gas routed to a combustion process.**

[644] **The only nitrogenous compound present in the process gas routed to the flare at the TEC will be ammonia (NH_3). CCG calculated hourly, per event, and annual NOx emissions from the flare using a reference emission factor for thermal NOx formation and an assumed conversion efficiency of NH_3 to NOx for fuel NOx formation from Table 4 of TCEQ's flare permitting guidance document.**

[645] **Ammonia content sampling or monitoring of the process gas routed to the flare is not required in the permit because fuel NOx emissions only comprise less than 1.5% of the total NOx emission and the ammonia content of the various process streams that could be routed to the flare can readily be quantified based on as-built heat and material balance data.**

used to establish a COS to H_2S ratio and this ratio will be applied to the continuous H_2S content monitoring results to determine COS emissions.

As shown in Table A-2.7 of Appendix A to Volume 3 of the Application, the carbon containing compounds which could contribute to CO_2 emissions from the flare are CO_2, CO, CH_4, COS, HCN, and methanol.[646] The majority of the GHG emissions from the flare are from the CO content of the process gas and will be quantified based on the output from the continuous process gas flow rate and operational monitors for CO content. The CO_2 content of the flared process gas based will be estimated on as-built heat and material balance data. For CH_4, Condition 4.1.8-2(f) requires continuous operational monitoring for the supplemental natural gas flow rate to the flare header from which the CH_4 flow rate will be calculated. For the portion of the CH_4 flow rate in the process gas attributable to CH_4 found in syngas or off-specification SNG, CH_4 content will be estimated based on as-built heat and material balance data. Finally, the monitoring methods described previously for quantifying emissions of COS, HCN, and methanol from the flare can be applied to determine the amount of these compounds present in the process gas routed to the flare. Based on this compilation of data, CCG must quantify CO_2 emissions from the flare on a monthly and annual basis to verify compliance with the flare limit for GHG [Condition 4.1.10-2(b)(iv)].

GHG emissions from the flare also include a contribution from N_2O. Similar to NO_x, N_2O is not found in the process gas routed to the flare, but is only formed as a by-product of combustion from controlling CO, VOM, and H_2S emissions. Thermal N_2O emissions will be calculated based on the process gas heat input rate and an AP-42 Chapter 1.4 emission factor for natural gas combustion. N_2O emissions from NH_3 combustion will be calculated based on the same data used to calculate fuel NO_x emissions. The relatively small contribution to CO_2e emissions from CH_4 and N_2O must be included in the monthly and annual flare CO_2e emission calculations required by Condition 4.1.10-2(b)(iv).

The permit requires CCG to demonstrate compliance on a continuous basis with the annual SO_2, NOx, CO, VOM, PM, COS, and CO_2e flare emission limits using a combination of continuous operational monitoring data, reference emission factors, and engineering estimates. With the ability to accurately quantify actual flare emissions based on cited requirements of the permit, the emission limits for the flare are practically enforceable.

POWER BLOCK CONDITIONS ARE NOT ENFORCEABLE

135. Emissions limits for startup and shutdown of the combustion turbines in the power block are not enforceable. Condition 4.2.2 of the Draft Permit would exempt startups, shutdowns, and malfunctions from BACT emission limits for NO_x, CO, VOM, and CO_2. These are

[646] **Depending on the type of gasification block startup or shutdown event, CO is expected to comprise between 64% and 76% of the total carbon containing compounds routed to the flare on a per event basis. The flow rate of CO_2 in the process gas routed to the flare during gasification block startups and shutdowns comprises between 2.5% and 5.0% of the total carbon containing compound flow rate, and therefore, direct CO_2 emissions from the CO_2 present in the flared process gas comprise a relatively small fraction of the total GHG emissions from the flare. CH_4 comprises between 19% and 33% of the process gas routed to the flare, but most of this methane is derived from supplemental natural gas fed to the flare header.**

addressed in Condition 4.2.2(d), which refers to separate limits specified in lbs/event in Condition 4.2.6(a) (Attachment 1, Table I). Table I sets separate emission limits for NOx, CO, VOM, and CO_2 for cold starts, warm starts, hot starts, and shutdowns, but does not set any limits at all for malfunctions. These limits for startup and shutdown are not enforceable.

First, the Draft Permit does not define cold start, warm start, and hot start, making application of these limits to any given event ambiguous. The definitions in the Application at 7-15 should be incorporated into the permit. Further, each of these types of events occurs at different frequencies and lasts for different durations, and therefore has different emission profiles, which have the potential of affecting compliance with 1-hour NAAQS and PSD increments. The Draft Permit does not identify or sufficiently limit the frequencies of cold starts, warm starts, and hot starts.

Second, the Draft Permit does not require any monitoring to determine compliance with these startup and shutdown limits. Rather, Condition 4.2.2(d) states that compliance is to be "determined based on engineering analysis and calculations." The Draft Permit and supporting record are silent as to what engineering analysis and calculations are required by Condition 4.2.2(d), preventing any review. Condition 4.2.7(a)(i)(A), emission testing, notes that "[i]n addition, the Permittee may also perform measurements to evaluate emissions at other loads and operating conditions [other than at maximum production]," making it clear that testing is at the discretion of the CCG. The Application at p. 7-14, on the other hand, states that "[c]ompliance with these limits will be determined via CEMS for NOx and CO."

Third, neither the Application, the Draft Permit nor the supporting record, mentions any testing for VOM. The Application at p. 7-14, for example, states "[f]or VOM, compliance will be determined by recordkeeping and manufacturer estimates." This is circular and does not require that the manufacturer estimates ever be confirmed. Thus, compliance is never determined for VOM emissions during SSM events, rendering the limits in Attachment 1, Table I unenforceable.

Fourth, the Draft Permit includes annual limits for the combustion turbines in tons per year. The Application suggests that these are "an alternative to separate short-term limits" as they include startups and shutdowns.[647] However, they contain the same problems discussed above, namely, no requirement to actually measure the startup and shutdown emissions to include in the tally for the annual limits. Thus, they do not cure the defect of no monitoring.

The limits for NOx, CO, VOM and CO_2 emissions in Attachment 1, Table 1 of the permit are enforceable. CCG must continuously monitor CO, NOx, and CO_2 emissions using CEMS to directly demonstrate compliance with these limits, including during periods of startup and shutdown [Condition 4.2.8]. There is no available method to directly measure VOM emissions during startup and shutdown periods, which were included in the permit based on engineering knowledge that the turbines would likely be unable to meet the steady state VOM limit during these periods, as VOM stack testing during transient startup and shutdown conditions is not possible. The CO

[647] Ap., v. 1, p. 7-14.

emissions data from the CEMS will be used as an indicator of VOM performance during these periods, as is commonly provided for by USEPA.

Finally, in response to this comment, definitions for cold starts, warm starts and hot starts have been included in the issued permit. (See Attachment 1, Note b). However, limits on the frequencies of startup and shutdown were not included as they are adequately limited by the annual emission limits in the permit, which achieve the overall goal of both restricting and minimizing emissions. The claim in this comment that there is "no requirement to actually measure the startup and shutdown emissions to include in the tally for the annual limits" is incorrect based on the use of a continuous emissions monitoring system.

136. Malfunctions of the combustion turbines are exempted from BACT requirements, but are not covered by separate limits as required by the Clean Air Act. Because BACT requirement results in an "emission limitation," *see* 42 U.S.C. § 7479(3), App. E, PSD permitted sources must always comply with BACT; thus a permitting authority cannot exempt start up, shut down, or malfunction events. Emissions limitations are designed to "limit[ ] the quantity, rate, or concentration of emissions of air pollutants on a *continuous* basis." 42 U.S.C. § 7602(k), App. F (emphasis added). As a result, although emission limits may vary to reflect special conditions during malfunction and atypical performance periods, an agency may not waive them. *See In re Indeck-Elwood, LLC,* PSD Appeal No. 03-04, slip op. at 66, 2006 WL 3073109 (EAB 2006) ("It is well established that BACT requirements cannot be waived or otherwise ignored during periods of startup and shutdown."); *see also In re Rockgen Energy Center,* 8 E.A.D. 536, 553, 1999 WL 673224 (EAB 1999) (quoting EPA guidance for the proposition that "[s]tartup and shutdown of process equipment are part of the normal operation of a source . . . . Accordingly, it is reasonable to expect that careful and prudent planning and design will eliminate violations of emission limitations during such periods"); *In re: Knauf Fiber Glass, GMBH,* 8 E.A.D. 121, PSD Permit No. 97-PO-06 (Feb. 04, 1999) ("There are no exceptions to the permit limits for periods of equipment malfunction, breakdown, or upset.") 65 FR 70,792, 70,793 (Nov. 28, 2000) (USEPA rulemaking "reiterat[ing] that, under the Act, all excess emissions during starts up, shuts down, or malfunctions episodes are violations of applicable emission limitations.").

Because BACT limits apply at all times, the permit's standards for start up, shut down, and malfunction periods must still be based on the BACT for the problems that are or may be encountered during those periods. Malfunctions in the power block might include, for example, reagent supply issues for the SCR, HRSG tube leaks, or electrical interruptions at the generator or substation. During these periods, control equipment and control measures would not necessarily perform normally. The Draft Permit would not regulate emissions during these events, which is contrary to the applicable law.

The permit includes BACT limits that are applicable during malfunctions. Per Condition 3.7(a), "the emission limits set by this permit, including BACT limits and other permit limits for emissions, apply at all times unless otherwise specified in a particular provision." The draft and issued permit made no exclusion for combustion turbine malfunction events for the PM/PM_{10}/$PM_{2.5}$, SO_2, CO, VOM, and CO_2 BACT limits. The combustion turbine NOx BACT limit in the draft permit did, however,

inadvertently exclude malfunction events. This was corrected in the issued permit in Condition 4.2.2(b)(ii) by removing the exclusion for malfunctions. Additionally, the lb/event startup and shutdown and annual emission limits for the combustion turbines in Attachment I Table 1 do not exclude malfunctions events, contrary to the suggestion made in the comment.

ROADWAYS AND OPEN AREA CONDITIONS ARE NOT ENFORCEABLE

137. The results of the BACT analysis are not required as enforceable permit conditions. For haul roads, the Application concluded that BACT is paving plus washing, sweeping or vacuuming to reduce 90% of the PM, PM_{10}, and $PM_{2.5}$. For open areas, the Application concluded that BACT is dust suppression to reduce 90% of the PM, PM_{10}, and $PM_{2.5}$.[648] The Draft Permit does not require 90% reduction in PM, PM_{10} or $PM_{2.5}$ emissions, but rather Condition 4.11.2 sets an opacity limit of 10% without explaining where it came from or how 10% opacity guarantees that dust suppression will be used to reduce emissions by 90% to achieve the emission rates in lb/hr that were included in the air quality modeling.

The haul road BACT determination is enforceable as the permit required compliance with an opacity limit and a number of work practices control requirements, which accommodate appropriate operational flexibility. Dust control programs must be able to appropriately respond to the full range of operations and weather conditions, and broad BACT control requirements are most appropriate. Condition 4.11.2 limits opacity to 10% and monthly visual inspections must be conducted. Condition 4.11.5 requires a dust control plan, including a detailed description of the emissions control technique(s), including: typical application rate, type and concentration of additives, frequency of application, triggers for additional control (e.g., observation of 8 percent opacity), and calculated control efficiency. Additional permit conditions require tracking of PM emissions and operating parameters to maintain fugitive emissions within the permit limits which were set based on the emission calculations in the permit application (Conditions 4.11.6 and 4.11.9). The opacity limit and required work practice standards will ensure that BACT is implemented.

138. The emission rates used in modeling are not enforceable. The Application estimated the emissions that would result from hauling and handling coal, slag, liquid sulfur, filter cake, ZLD solids, and methanol, among others. These emissions were included in the air quality modeling for PM_{10} and $PM_{2.5}$ ambient air quality standards. The emission calculations were based on a large number of assumptions which must be realized in practice to assure that standards are not exceeded. While it is difficult to directly measure the PM, PM_{10}, and $PM_{2.5}$ emissions from haul roads, it is feasible and facile to measure the input assumptions used in these calculations to verify the emission calculations. These verifiable assumptions include roadway silt content, number and type of vehicles, vehicle weights, distances travelled, and maximum daily throughputs of various hauled materials. The Draft Permit does not limit any of these inputs. Thus, the emissions included in the air quality analysis are not enforceable and the analyses cannot be used to conclude that the project would not have any adverse air quality impacts.

[648] Ap., v. 1, pp. 11-2 to 11-3.

The permit contains requirements that ensure the enforceability of the modeled emission rates by (1) requiring work practice standards that detail the emissions control technique(s), as addressed elsewhere, (2) requiring PM emissions and operating parameters to be tracked, such as traffic/vehicles associated with receipt of material and compliance with the PM emission limits, and (3) silt testing requirements on various roadway segments. The emission rates used in the air quality analysis are practically enforceable by the permit.

MATERIAL HANDLING CONDITIONS ARE NOT ENFORCEABLE

139. The emissions limits for the inactive storage pile (PIL1 - PIL3) and certain transfer points (TP1- TPI3) are not enforceable. The modeling analysis assumes very low, unsupportable and erroneous emissions for PM_{10} and $PM_{2.5}$ emissions from three transfer points (TP1-3) and inactive storage pile sources (PIL1-3) that are not controlled by a dust collector. Comments infra discussed the errors in these calculations. These emissions were underestimated by over a factor of 30. The Draft Permit contains no mechanism(s) to discover this underestimate.

The conditions in the Draft Permit do not assure that these low emission rates, required to avoid exceeding the 24-hour PM_{10} and $PM_{2.5}$ increments and NAAQS, are achieved in practice. The emissions that were modeled are not included in the Draft Permit as emission limits. The key inputs used to calculate these emissions are also not stated as Permit conditions or measured: wind speed, silt content, moisture content, and control efficiency. Thus, even a calculation of emissions to demonstrate compliance is not feasible. Compliance with an opacity limit does not assure that the modeled PM_{10} and $PM_{2.5}$ emissions are achieved in practice.

The permit contains adequate provisions to ensure that the modeled emission rates are achieved in practice without the need to set limits on the wind speed, silt content, moisture content, and control efficiency. The wind speed varies from year-to-year and thus a five-year average of actual wind measurement data for the area represents average conditions and does not require further verification. Silt content of unpaved storage yards for dozer/loader traffic PM emission calculations is conservatively based on data for plant roads at Western surface coal mines in AP-42 Table 13.2.2-1. As discussed elsewhere, the silt content for the piles is conservatively based on the AP-42 Table 13.2.4-1 value for coal piles at Coal-Fired Power Plants and the silt content is not an input for the transfer points. The basis of the coal moisture content used in material handling fugitive PM emission calculations has already been discussed. Since the emission calculations are either based on actual measurements or conservative emission factors, they are appropriate for use in calculating emissions from TEC emission units. Control efficiency values are based on AP-42, USEPA reference documents, and other reference literature that are widely used for calculating fugitive emissions and forming the basis of air permits.[649]

[649] **National Pollutant Inventory (NPI) Emission Estimation Technique Manual for Mining Version 2.3, Environment Australia, December 5, 2001, Table 3. Estimated Control Factors for Various Mining Operations and USEPA's Model Plant Control Cost Estimates for Units**

In addition, Condition 4.3.6.b limits annual PM emissions from coal handling and storage sources (including: TP1-3, PIL1) and separately limits the annual particulate matter emissions from slag pile maintenance (including PIL2-3). Operating parameters are required to be tracked along with detailed documentation for the level of emissions control achieved through work practices (Condition 4.3.10.b.iv).

140. BACT is not required for certain units. The Application concluded that BACT for the transfer points (TP1-3) is wet dust suppression as a work practice standard with compliance based on an opacity level of 10%.[650] The Application also concluded that BACT for wind erosion (PILl) and maintenance transfer (PIL1-3) for the inactive storage pile is wet dust suppression and pile compaction as work practice standards.[651]

First, the Condition 4.3.5(d) of the Draft Permit does not require pile compaction, but rather only the implementation and use of control measures that "minimize visible emissions of PM…" The phrase "minimize visible emissions" is ambiguous and does not necessarily require the BACT control of compaction.

Second, the BACT control required in Condition 4.3.2(d) of the Draft Permit — "wet dust suppression" — is ambiguous. What does the term "wet dust suppression" mean? Watering only? Does it require chemical suppressants and binders? How frequently must the suppressant be applied to assure the control levels required to protect the NAAQS and PSD increments? Watering only is inconsistent with both the Application and modeling, but is a reasonable interpretation of the Draft Permit language. The estimated PM_{10} and $PM_{2.5}$ emissions assumed high dust control efficiencies, which require continuous application of chemical suppressant and binder. The Draft Permit lacks any description whatsoever of what is required to achieve the assumed control efficiencies, 50% to 90%, factors such as frequency and amount/type of suppressant applied.

Third, the measures that would be implemented pursuant to Condition 4.3.5(d) of the Draft Permit to control fugitive emissions will be identified in a plan that would be submitted later. This would violate the public review requirements of the PSD program, preventing public comment.

Fourth, Condition 4.3. 3-1(c) of the Draft Permit does not require compliance with 10% opacity at TP2 or TP3. The only opacity monitoring required in the Draft Permit is that pursuant to NSPS Subpart Y. This provision only applies to TP1.[652] Thus, no opacity monitoring is required for TP2 and TP3 or PILl.

BACT for the material transfer points (TP1-3) and storage piles (PIL1 - PIL3) is wet dust suppression (Condition 4.3.2(d)). In the issued permit, requirements are clarified. Specifically for the inactive storage pile chemical dust suppressants must be used. There are other provisions that require the use of chemical surfactants in minimizing fugitive emissions for the inactive storage pile. Condition 4.3.3-1.d. requires

---

Subject to NSPS for Coal Preparation Plants, April 2008. These documents were used extensively for developing emission factors and control efficiencies for the recently finalized NSPS Subpart Y (Coal Preparation and Processing Plants) rule amendments.

[650] Ap., v. l, p. 8-11.

[651] Ap., v. l, p. 8-18.

[652] Ap., v. 1, p. 4-12, Table 4-2.

a fugitive dust control plan per the Subpart Y NSPS, Conditions 4.3.6(b) and 4.3.10(b)(iv) limit the annual PM emission rates and require detailed documentation for the level of emissions control achieved. For transfer points, TP1-TP2 clarifies water sprays shall be applied to achieve a 50 percent nominal control efficiency, and for TP3 no additional controls are necessary since the inactive coal pile will have chemical suppressants applied and an inherent chemical latency will minimize fugitive coal dust from this source. Furthermore, TP1-3 have annual emission limits and a requirement to track emissions and document the level of emissions control achieved through work practices (Conditions 4.3.6(b) and 4.3.10(b)(iv)) that will require TEC to achieve emission rates and control efficiencies represented in the permit application.

Since the slag is a vitreous (glass-like) material with a negligible silt content and very high moisture content (~40 percent) the temporary slag and landfill slag piles (PIL2 and PIL3) will essentially not have any fugitive emissions from wind erosion or pile maintenance and the BACT determination for dozer and loader vehicle emissions from traveling on/around the pile is specified in the conditions for roadway (Section 4.11 of the permit) which requires a written operating program and a 10 percent opacity limit. These conditions specify BACT for the material handling units and include requirements to demonstrate and record that the control efficiencies are met.

The comment also questions the later submittal of the fugitive control plan and it not being a part of the public review period. TEC is required to implement a fugitive coal dust emissions control plan in accordance with the NSPS Subpart Y for PIL1, TP2, and TP3 (Condition 4.3.3-1(d)). Per 40 CFR 60.254(c)(4), fugitive coal dust emissions control plans must be prepared and submitted prior to startup, not prior to permit issuance. Furthermore, since the most effective measures of minimizing fugitive coal dust and implementing a control plan can change with changing conditions at a facility, it is appropriate to have permit conditions that outline the general elements of a control plan. In developing the control plan requirement under the NSPS Subpart Y, USEPA recognized that facility conditions change and there was a need for a clause providing for sources to "revise their plan as needed to reflect changing conditions at the source."[653] All fugitive coal dust emissions control plans have to be submitted by the agency to ensure that all NSPS Subpart Y facilities are meeting the same objectives. It is not practical to include specific plan requirements as permit conditions.

Lastly, the comment observes that the Draft Permit would not set a 10% opacity limit for TP2 or TP3. A 10% opacity requirement was not believed necessary as part of the BACT determination for TP2 or TP3, since the units were subject to the fugitive coal dust emissions control plan and not the opacity requirement under the Subpart Y NSPS. The control plan along with the permit Condition 4.3.9 to conduct monthly inspections will ensure that no visible emissions from TP2 or TP3 are visible off-site. However, a 10% opacity limit is included in the issued permit (See Condition 4.3.2(i).

EQUIPMENT LEAK CONDITIONS ARE NOT ENFORCEABLE

[653] **40 CFR 60.254(c)(4)(ii)**

141. Definitions are not provided for the different categories of process streams that serve to determine which control measures are applicable. The emission calculations assumed very high control efficiencies, typically 97% emission reduction, for certain components controlled by LDAR programs. The application characterized these components as being "high VOM fraction process streams" or "high VOM and H_2S fraction process streams," without ever defining these terms.[654]

Condition 4.9.2(a)(i) of the Draft Permit adds to the ambiguity by applying LDAR only to unidentified components in triethylene glycol service in the SNG drying process; components in methanol, propylene, and acid gas service within the AGR unit; components in sour gas and acid gas service in the SRU process; and components in methanol and propylene service in miscellaneous minor process areas. The draft permit does not define these terms or identify the subject components on piping and instrumentation diagrams.

Proper identification is required to assure that the reductions assumed in the emission calculations (and used as the basis for eliminating more effective controls as BACT) are actually realized. How much methanol or propylene must be in the stream to qualify as in methanol or propylene service? What are sour gas and acid gas? How much H_2S, for example, must be present in a process stream to render it "sour" or to classify it as "acid gas?"

The permit should require an explicit inventory of the components subject to LDAR, *i.e.*, location on P&ID that is tied to the assumptions in the emission calculations to assure that the reductions assumed in the emission calculations are achieved. The Permit also should be modified to define all terms used in establishing the LDAR program to eliminate ambiguity.

The provisions of Conditions 4.9.2(a)(i)(A) to (C) identify which process streams and components are subject to the LDAR program in Condition 4.9.6. As previously discussed, appropriate reduction credits were used for high VOM streams consistent with TCEQ guidance for LDAR programs as selected as BACT for TEC. Descriptions of each ELC process area provided in Section 6.6 of the application describe and identify by name the high VOM process streams that are required to be monitored as part of the LDAR program, and the relevant portions of each of these descriptions were incorporated into the Draft Permit.[655]

The permit requires that ELC on each of these specifically-identified streams are monitored under the BACT LDAR requirements for high VOM streams (Condition 4.9.2(a)(i)). It is not necessary for the permit to further define each controlled component from each process stream.

Defining a threshold of methanol concentration for a stream to identify it as a methanol stream subject to LDAR is unnecessary. The TEC will not have mixed streams of widely varying concentrations, such as the overheads from a refinery, with

[654] See Ap., v. 1, Appx. C, Tables C-24.2, C-25.2, C-26.2, and C-27.2 and v. 3, Appx. A, Tables A-16.2 and A-17.2.

[655] **All connectors contacting these process streams are included in the LDAR program. No streams were left unidentified, and no stream is ambiguous. The difference between a high VOM stream and low VOM stream is not slight. For example, in ELC1 the low VOM streams have an average stream composition of 0.1 percent VOM. The high VOM streams in ELC1 all exceed a VOM stream composition of 98 percent. This obvious separation between low and high is not ambiguous.**

potential variations in the service type based on the materials being handled. The methanol streams subject to LDAR at TEC all include "methanol" in the process stream description, and all contain a significant concentration of methanol (ranging from approximately 77% for the Methanol Drain to nearly 100% for Lean Methanol). A similar conclusion can be made for the permit's identification of propylene streams subject to LDAR. The propylene stream at TEC will be pure propylene for use as a refrigerant in a closed loop system within the AGR process area.

It is also unnecessary for the permit to define an H_2S concentration to differentiate between sour and acid gas. Condition 4.9.2(a)(i)(C) requires LDAR for components for both sour and acid gas streams with no exemption from LDAR monitoring based on H_2S composition.

The permit further classifies that VOC service generally means that equipment contains or contacts a process fluid that is at least 10 percent VOC by weight, which is consistent with the term used in LDAR requirements of other permits (e.g., Power Holdings, Cash Creek, and Kentucky NewGas).[656, 657, 658] The LDAR requirements for the TEC and these other planned coal gasification facilities that would produce SNG apply only to components in VOC service. All streams not specifically identified in Condition 4.9.2(a)(i) as high VOM streams subject to the LDAR requirements of the permit would have a VOM concentration far below 10%.

Given these circumstances, the permit does not need to provide an explicit inventory of the components subject to LDAR because the characterization of process streams in the permit will be clear and unambiguous.

The comment also suggests that the permit should define all terms used in establishing the LDAR program to eliminate ambiguity. The comment's assertion that the Draft Permit would be ambiguous is incorrect for reasons as discussed above. The permit need not include further definitions as suggested.

142. The required LDAR program would not cover all relevant pollutants. Equipment leaks contain many regulated pollutants, including VOCs, CO, H_2S, COS, CH_4, and CO_2, among others. However, the LDAR requirement, which is assumed in the emission calculations to control all of these pollutants, in Condition 4.9.2.a(i) of the Draft Permit would be applied only to VOM emissions. The term "VOM" is not defined anywhere in the Draft Permit, but presumably is volatile organic material. This term is ambiguous and must be defined in the permit to assure enforceability.

The LDAR program is assumed to control the same percentage of emissions of non-VOM components, such as COS, H_2S, CO, CH_4, and CO_2, as VOM, or 97% for most all components, as VOM. However, the Draft Permit would not require LDAR for these other

---

[656] **IEPA, *Construction Permit – PSD Approval NSPS Emission Units, for Power Holdings of Illinois, LLC* (Permit ID No. 081801AAF), October 26, 2009, p. 83.**

[657] **Kentucky Division for Air Quality, *Air Quality Permit Issued under 401 KAR 52:020 for Cash Creek Generation, LLC*, May 5, 2010, p. 60, available at http://dep.gateway.ky.gov/eSearch/Search_AI.aspx**

[658] **Kentucky Division for Air Quality, *Air Quality Permit Issued under 401 KAR 52:020 for Kentucky Syngas, LLC*, September 24, 2010, p. 38, available at http://dep.gateway.ky.gov/eSearch/Search_AI.aspx**

pollutants. The LDAR monitoring requirements in Condition 4.9.6 only require monitoring for VOM. The other compounds can be reasonably expected to have different leak rates than VOM due to physical and chemical differences (*e.g.,* size of the molecule affects the amount that can escape through a given hole size). If there is no requirement to monitor these non-VOM components, there is no guarantee that the assumed control efficiency (93% - 97%) will be achieved and thus no assurance that the source is minor for HAPs and is controlled by BACT. The Permit must be modified to require monitoring for all non-VOM components assumed to be controlled by LDAR.

While equipment leaks may involve different pollutants depending on the material being handled, the LDAR requirements in the permit specifically address control of only VOM for the following reasons:

1. **LDAR requirements were defined as BACT only for high VOM streams, as part of the top-down BACT evaluation for VOM emissions from equipment leak components. The small amount of emissions of other pollutants that are also reduced by LDAR as a co-benefit is however reflected in the BACT limits for the other pollutants. The LDAR program implemented for high-VOM components will reduce CO emissions by 1.9%, CO_2 emissions by 4.8%, and CH_4 emissions by less than 0.1%.[659]**

2. **The high VOM process streams have a composition of greater than 77 percent VOM, with many streams greater than 98 percent VOM. Monitoring of VOM, the primary constituent, will ensure appropriate identification of leaks under the LDAR requirements to allow for the very small emissions reductions claimed for CO, CO_2, and CH_4.**

3. **The nature of equipment leaks is that when there is a leak, the entire stream will be leaking at a composition similar to the process stream it contains. Mitigating leaks of the primary constituent of a process stream will act to mitigate emissions of all other pollutants present in the process stream.**

The comment's assertion that other compounds from the same leaking component will have different leak rates is not reasonable. The comment offers no support or analysis backing this claim. The reasons why equipment leak component emissions rates are not based on the molecular size of the pollutant have already been explained.

For these reasons, it is not necessary that the permit specifically identify that the LDAR program also achieves concurrent reductions of other pollutants. Conditions 4.9.2(d) and 4.9.5 include appropriate facility-wide limits of all pollutants emitted from the equipment leak components, which account for the concurrent reduction of all pollutants at the same rate for high VOM components. CCG will be required to demonstrate compliance with these numeric BACT emission limits in accordance with

[659] CO Emissions % Reduction from LDAR on High-VOM Streams = 1 – [30.5 tpy CO BACT limit for ELC (Condition 4.9.2(d) /31.1 tpy uncontrolled CO emissions from ELC (page 6-49 of Volume 1 to the Application)] = 1.9%. CO_2 Emissions Reduction for LDAR on High-VOM Streams = 1 – [177.4 tpy CO_2 emission rate with LDAR (page 6-36 of Volume 3 to the Application)/186.3 tpy uncontrolled CO_2 emissions from ELC (page 6-35 of Volume 3 to the Application)] = 4.8%. CH_4 emissions % reduction from LDAR on high VOM streams is less than 0.1% based on same controlled and uncontrolled emissions rates listed on pages 6-38 and 6-39 of Volume 3 to the application.

Condition 4.9.7(c). Condition 4.9.5 also requires CCG to demonstrate compliance with the ELC emissions limits using an appropriate USEPA methodology for estimating emissions from leaking components. As discussed previously, CCG will use either leak-no leak data in the screening ranges approach or measured concentrations in the correlation approach from LDAR monitoring data to determine actual emission factors for each ELC subject to the LDAR program. These emission factors can then be speciated based on known stream compositions from as-built heat and material balance data to account for actual emissions of VOM and any other regulated air pollutant present in the high-VOM streams subject to LDAR including CO, CH_4, CO_2, and individual and combined HAPs. No permit modification is necessary to ensure emissions of non-VOM pollutants remain below their corresponding emissions limits because the results of LDAR monitoring for leaks of VOM compounds from high VOM process streams can be used to accurately quantify emissions from non-VOM pollutants for direct comparison against the permit limits in Condition 4.9.5.

The comment also raises concerns about the enforceability of the COS and H_2S emissions reductions that will be achieved through the LDAR program applied to high-VOM process streams. While the LDAR program applied to high-VOM process streams will concurrently offer significant reductions in H_2S, and COS, no additional permit provisions are needed to make the H_2S and COS reductions enforceable. In the SRU process area, the sour gas and acid gas process streams subject to LDAR do contain more H_2S than they do VOM but any streams that contain COS or H_2S also contain measurable concentrations of VOM that could be readily monitored using Method 21.[660] Therefore, no separate instrument monitoring specifically for H_2S or COS needs to be added to the permit, since a single instrument monitoring program calibrated for VOM can be used to simultaneously ensure equivalent reductions in emissions of VOM, H_2S, and COS from affected process streams in the AGR and SRU process areas.

Finally as already discussed, volatile organic material (VOM) is a defined term in Illinois regulations (see 35 IAC 211.7150). It is synonymous with the federal term volatile organic compounds (VOC). As such, it need not be defined in the permit.

143. There are errors in the emission limits in the Draft Permit. Top controls were rejected as BACT based on the cost per ton of pollutant removed. The "uncontrolled tons of pollutant" is an important factor in this cost calculation and depends directly on uncontrolled emissions. Further, the Application claims that the TEC is a minor source for HAPs as the emissions are less than 10 ton/yr for any individual HAP or 25 ton/yr total HAPs. Thus, the permit must contain enforceable emission limits on pollutants involved in these determinations: VOCs, CO, COS, H_2S, CO_2e. Limits on these pollutants must be demonstrated through actual measurement. The Draft Permit contains some limits for equipment leaks but they are incomplete, contain errors, and are not enforceable. First, the Draft Permit contains duplicative emission limits for fugitive components, in Conditions

[660] As shown in the process-area specific stream composition data for LDAR and non-LDAR components in Sections C-24 to C-27 of Appendix C, the only two process areas that contain process streams controlled by LDAR with COS and H_2S present are the AGR process area (designated as ELC2) and the SRU process area (designated as ELC3). In aggregate the process streams subject to LDAR in the AGR process area contain 77% VOM compared with only 0.66% COS and 6.0% H_2S, and all process streams that contain COS and H_2S also contain significant amounts of VOM which would be readily picked up by a organic vapor analyzer operated in accordance Method 21.

4.9.2(d) and 4.9.5. The former should be eliminated. Second, the emission limits in Draft Permit Condition 4.9.5 contains two errors that should be corrected. As drafted, it states: "Emissions of VOM, CO, CO_2e, COS, and methanol from affected component shall not exceed 2.44, 30.5, 177.4, and 1,255, 1.00 and 1.05 tons/year." This condition should state: "Emissions of VOM, CO, CO_2, CO_2e, COS, and methanol from affected component shall not exceed 2.44, 30.5, 177.4, 1,255, 1.05, and 1.00 tons/year."

The TEC will be a non-major or "area source" of HAPs. To ensure that the TEC remains an area source of HAP, the permit includes limitations on the primary individual HAPs emitted from equipment leak components, COS and methanol. Condition 3.4(d) also requires that CCG keep records of the annual emissions of HAPs to demonstrate that the TEC is not a HAP major source. The comment asserts that the Draft Permit contains two errors which prevent the permit from adequately limiting emissions of HAPs to ensure the plant is an area source of HAP.

The comment's first "error" is that the Draft Permit contains duplicative emission limits for equipment leak components in Conditions 4.9.2(d) and 4.9.5. These limits are not duplicative and the approach for ELC limits is the same used for other emission units at the TEC. Condition 4.9.5 contains all permit limits for ELC and Condition 4.9.2(d) contains only the BACT limits for PSD regulated pollutants. In addition to the numeric emission limits, Condition 4.9.5 also identifies that compliance must be determined by appropriate USEPA methodology for estimating emission from leaking components.

The second error correctly observes that Condition 4.9.5 in the Draft Permit omits CO_2 from the identified list of limited pollutants, yet includes a numeric emission limit for CO_2 on a mass basis. This has been corrected in the issued permit.[661].

144. Limits for emissions from equipment leaks are not enforceable. The Draft Permit does not include any requirements to actually determine compliance with the emission limits. Rather Condition 4.9.5 simply stipulates that emissions must be determined using "appropriate USEPA methodology." This methodology is not further identified, *e.g.*, what emission factors would be used, what assumptions would be made about control effectiveness? How many components would be assumed and based on what? How would the emissions be speciated, *i.e.*, subdivided among the specific pollutants that are regulated?

No measurements are required to confirm that any of the inputs to this calculation are representative of the TEC, *e.g.*, emission factors, control efficiencies, component counts. Nothing in the Draft Permit measures fugitive leaks in pounds per hour or tons per year or requires that they meet the estimates used to reject control options as BACT based on cost in dollars per ton. Also, nothing specifically addresses any component of these emissions except VOM, which is measured by EPA Method 21. This method does not detect the

[661] In the issued permit, Condition 4.9.5 reads, "Emissions of VOM, CO, CO_2, CO_2e, COS and methanol from the affected components shall not exceed 2.44, 30.5, 177.4, 1,255, 1.05, and 1.00 tons/year, respectively, as determined by use of appropriate USEPA methodology for estimating emissions from leaking components."

inorganic compounds in the fugitive emissions, such as CO, CO_2, COS, and H_2S. Thus, these limits are not enforceable.

The Draft Permit allows CCG to carry out the exact same calculation, using the same inputs and assumptions, as was used to estimate emissions in the Application. These emissions became the emission limits in the Condition 4.9.5. Such an approach is a self- fulfilling prophecy that does nothing to ensure that the emission factors relied upon are accurate or that the assumed control efficiencies are actually being achieved. The USEPA has held that such circular demonstrations are not enforceable limits on PTE. *See, e.g., In re Peabody Western Coal Co.*, 12 E.A.D. 22, CAA Appeal No. 04-01 (Feb. 18, 2005).

While the Draft Permit does require measuring the VOM concentration in ppm of individual leaks, it never requires converting them to emission rates in tons per year and adding them up to see if they exceed the estimates contained in the application or the emission limit in Condition 4.9.5. No measurements of any kind are required for other regulated pollutants.

Leaks identified under the proposed LDAR program are not taken into account in any way in the compliance demonstration. Even if testing showed higher fugitive emission rates or lower control efficiency; even if the final component count is higher than the assumed preliminary estimates; the Draft Permit bases compliance on the emission limits only on an undefined calculation that takes none of this into account.

As a result, there is no consequence to CCG if leaks occur more frequently than assumed in the emission calculations or more components are installed than assumed in the application. It is impossible to violate any of the emission limits in Condition 4.9.5 regardless of how many leaks occur under the Draft Permit terms. The Draft Permit does not require that emissions from leaks above the levels assumed in the application ever be quantified or tallied. If the number of leaks, concentration of pollutants in the leaks, or the size of the leaks exceeds the application's assumptions, CCG is not even required to identify this problem, nor report it.

Thus, while CCG is required to carry out an LDAR program, CCG never has to use this program to determine whether the facility has more leaks or more components or poorer repair efficiency and thus more emissions than assumed to reject the top technologies as BACT and to classify the TEC as a minor source for HAPs. In sum, the emission limits in Condition 4.9.5 are unenforceable as a practical matter.

This is a major concern because the coal gasification industry is a new industry with no emission history. Further, recent evidence reviewed elsewhere in these comments indicates that potential emissions from equipment leaks may be underestimated by an order of magnitude. The permit emission limits should be based on actual measurements at existing coal gasification facilities, or confirmed through periodic direct testing at TEC after it is built using the bagging techniques described in the 1995 USEPA report, *Protocol for Equipment Emission Estimates*[662] or more advanced, state of the art remote sensing methods, reviewed elsewhere in these comments.

[662] USEPA, *Protocol for Equipment Emission Estimates, EPA-453/R-95-017* (Nov. *1995),* available at http://www.epa.gov/ttnchie1/efdocs/eguiplks.pdf, (Commenter's Exhibit 150)

This comment generally provides a compilation of claims already made in other comments. Each of those claims has already been addressed elsewhere.[663]

---

[663] **A brief review of those responses follows.**

The comment inquires as to how CCG will comply with the requirements of Condition 4.9.5 to demonstrate compliance with the numeric BACT emission limits for equipment leak components in accordance with the appropriate USEPA methodology. As part of the LDAR instrument monitoring required by Condition 4.9.6, CCG must generate measured concentrations for each monitored component which can be used in conjunction with USEPA's screening ranges or correlation emission factors in Tables 2-5 and 2-9 of the *Protocol for Equipment Leak Emissions Estimates* and assumptions about stream composition to estimate actual annual emissions for all pollutants. Using measured data (where available) will provide the most accurate estimate of emissions from equipment leak components at the TEC for comparison against permit limits, and these calculations will ensure that CCG is meeting the numeric BACT emission limits of Condition 4.9.5.

The comment also claims that no measurements are required to confirm that any of the inputs to the BACT emission calculations is representative of the TEC. However, the permit requires verification that actual equipment leak components emissions are less than the BACT limits considering emission factors, actual emissions calculations, control efficiencies, and component counts. As such, the permit would require TEC to meet the emission estimates used to reject control options as BACT. Condition 4.9.5 requires CCG to demonstrate compliance with ELC emission limits using an appropriate USEPA methodology. For components subject to the LDAR program, this appropriate methodology will include either the screening ranges or correlation approach recommended by USEPA for ELC that are subject to periodic leak monitoring. CCG cannot carry out the same calculations presented in the Application for components subject to the LDAR program as the compliance calculations must address actual circumstances and operations. CCG cannot use the SOCMI without ethylene or LDAR control credits in the actual emission calculations for components subject to the LDAR program as this would not be considered an appropriate USEPA methodology. For the remaining ELC that are not subject to a LDAR program, CCG may use the uncontrolled SOCMI average without ethylene emission factors in conjunction with actual component counts and stream composition data for all components that are not known to be leaking in any given operating period, as this is consistent with established and appropriate USEPA methodology. If on the other hand a leaking component not subject to LDAR is identified through the good work practices required in Condition 4.9.2(a)(ii), CCG is required to generate a leaking component record [Condition 4.9.7(b)] and must use the data from this record in conjunction with follow-up organic vapor analyzer monitoring data to determine the actual emission rate from the leaking components. With the exception of the emission factor for non-leaking components not subject to the LDAR program, CCG cannot simply replicate the emissions for uncontrolled ELC presented in the Application, but must instead use actual component counts, stream composition estimates, and leak records to accurately quantify actual emissions for ELC not subject to the LDAR program, which is consistent with USEPA recommendations for process streams that are not subject to LDAR programs.

This comment and other related comments essentially recommends a complete overhaul of the emission calculation methodology that USEPA has endorsed in the Equipment Leak Protocol for ELC at chemical plants for the past 26 years because of perceived underestimates of ELC emissions. All of the examples used to justify the blanket statement that pervasive underestimates of ELC emissions are occurring across all industries are based on irrelevant and incomplete studies from existing sources in the petroleum refining industry. The conclusions of these studies from the refinery industry would have little relevance when evaluating the adequacy and enforceability of the permit for TEC for the reasons previously discussed regarding the differences between the TEC and refineries. The permit conditions for ELC are complete, robust, and consistent with USEPA recommended approaches for regulating emissions from ELC and quantifying emissions from ELC.

The comment asserts that the permit should require measurement of fugitive leaks in pounds per hour or tons per year. This is a clear misconception of LDAR and appropriate monitoring requirements for equipment leak components. CCG must develop lb/hr/component rates utilizing the measured concentration of leaks through the required LDAR monitoring under Condition 4.9.6 in accordance with USEPA's screening ranges or correlation equations, discussed previously. These rates will then be used in calculating actual emissions to demonstrate compliance with the permit limits.

The permit appropriately requires monitoring of VOM by USEPA Method 21 to control emissions for the high VOM streams subject to LDAR, as already discussed elsewhere.

The comment incorrectly states that the permit would include a "circular demonstration" of compliance, which would let CCG verify compliance with the numeric BACT emission limits using the same calculation as that used for potential emissions. Because CCG is required to utilize actual measurements from ELC monitored under LDAR to estimate emissions in accordance with Condition 4.9.5, the comment's assertions that the permit "never requires converting them to emission rates in tons per year," "Leaks identified under the proposed LDAR program are not taken into account in any way in the compliance demonstration," and " it is impossible to violate any of the emission limits in Condition 4.9.5 regardless of how many leaks occur" are wrong. Condition 4.9.2(d) of the Draft Permit includes justified numeric BACT emissions limits. For ELC subject to the LDAR program, compliance is required to be verified in accordance with USEPA methodologies using either the screening ranges or correlation approach, both of which rely on actual measured concentrations from the LDAR monitoring. If CCG does not adhere to the stringent LDAR requirements and large numbers, high concentrations, or a great magnitude of leaking components result, the actual emissions calculated in accordance with the screening ranges or correlation approach will exceed the limits in the permit and would have to be identified in deviation reports, as required by Condition 4.9.8.

The last element of this comment is self-contradictory. The comment recognizes that the modern coal gasification industry is a new industry with very limited emissions history. It immediately follows with a statement claiming that recent evidence presented in other comments indicates potential emissions from equipment leaks may be underestimated by an order of magnitude. If the coal gasification industry has no emission history, as the comment acknowledges, there is no evidence that equipment leak components from coal gasification facilities are underestimated or that, given the nature of these plants, that they will have difficulty in appropriately and correctly implementing LDAR programs.

Through the monitoring, recordkeeping, and reporting requirements of the LDAR program, as well as the referenced USEPA calculation methodologies for quantifying actual emissions from equipment leak components, the permit includes appropriate, practically enforceable, and stringent requirements for verifying BACT and permit limits are met. These comments suggest only one enhancement to the provisions of the Draft Permit. In the issued permit, Condition 3.4(d) requires that the emission records for emissions of HAPs from the plant be accompanied by supporting documentation and calculations. A condition requiring this supporting information for the records for emissions, which CCG would have to maintain in any case, will facilitate review of the emission data of ELC to ensure that the data has been properly compiled and calculation, reflected actual operation of the TEC.

145. In Draft Condition 4.9.5, the emission limits for leaks from equipment components is expressed in tons per year without any indicated averaging time. In Draft Condition 4.9.8, reporting is only required on an annual basis. Limits without averaging times are not continuously enforceable. Further, there are no restrictions at all during the first year of operation, when upsets and malfunctions are most likely.

The limits in Condition 4.9.5 are on a ton per year basis. Considering the nature of the ELC emissions which is a function of undesired leaks, short-term emission limits are not appropriate. Plant-wide Condition 3.7(e)(i) provides that "compliance with annual limits established by this permit shall be determined from a rolling total of 12 months of data, i.e., from the sum of the data for the current month and data for the preceding 11 months (12 month total), and shall consider all emissions, including emissions during startup, shutdown, and malfunction and breakdown." This is reasonable for equipment leak components while still providing for practical enforceability.

The comment incorrectly states that reporting is only required on an annual basis. The comment refers to Condition 4.9.8, which provides that CCG must notify the IEPA with the deviations reports required by Condition 4.1.11-1(c), which clearly provides that such reports must be submitted every 6 months. In addition, Condition 3.7(e)(i) requires CCG to demonstrate compliance with the annual ELC emission limits in Condition 4.9.5 on a 12-month rolling basis using monthly emission data.

The comment claims that there are no restrictions at all during the first year of operation when upsets and malfunction are most likely. The comment provides no supporting basis for their claim that upsets and malfunction for equipment leak components are more probable in the first year of operation. Equipment leak components are often passive sources of emissions which do not require a shakedown period. The seals and gaskets will be unworn and the newly installed equipment components will have been recently inspected and tested for integrity. In contrast to the comment's inappropriate suggestion, components likely will have fewer leaks during the first year of operation.

The permit would not exempt equipment leak components from meeting any of the requirements of Condition 4.9 during the first year (refer to Condition 3.7(e)). It is assumed that the comment's claim that "there are no restrictions at all during the first year of operation" is in response to its belief that reporting is only required on an annual basis, suggesting that CCG will not have to report compliance to the IEPA until after a year of operation. CCG is not relieved from permit requirements during the first year. Deviations are required to be reported to the IEPA at a minimum of every 6 months (Condition 4.1.11-1(c)).

HAP EMISSIONS LIMITS ARE NOT ENFORCEABLE

146. Condition 3.4(b) of the Draft Permit establishes facility-wide emission limits for lead and mercury. The permit requires analysis of the metals content a) in conjunction with emissions testing of the AGR unit and SRU; b) within 90 days of acceptance of a feedstock from a new source; c) within 90 days of a written request from IEPA; and d) at least once

every two calendar years. Condition 4.1.9 of the Draft Permit further requires that the Permittee keep a file containing the emission factors that the Permittee uses to calculate emissions of methanol, mercury, hydrogen chloride, hydrogen fluoride and other HAPs from the flare, the AGU, and the SRU with supporting documentation as well as records for total monthly and annual total HAP emissions from the flare, the AGU, and the SRU. However, nowhere does the Draft Permit set out the formula for the emission respective calculations, or require that CCG demonstrate that monthly or annual total HAP emissions do not exceed the permit limits. Thus, the emission limits for HAPs are not enforceable.

Condition 3.4(d) requires CCG to keep records for actual HAP emissions to verify that the TEC is not a major source for HAP emissions. Requiring periodic sampling and maintaining emission factors are sufficient building blocks to the calculation of actual HAP emissions at the source. The specific formulas that must be used for those emission calculations need not be prescribed by the permit. To do so, would do nothing to make the determination of HAP emissions more enforceable or more accurate. The comment fails to demonstrate how such specific calculation procedures would be appropriate, necessary or beneficial.

However, this comment has suggested one enhancement to the provisions of the permit. In the issued permit, Condition 3.4(d) requires that the emission records for emissions of HAPs from the TEC be accompanied by supporting documentation and calculations. A condition requiring this supporting information for the records for these emissions, which CCG would have to assemble and maintain in any case, will facilitate review of the emission data for HAPs to ensure that the data has been properly compiled and calculated, so as to accurately reflect actual operation.

COMMENTS FROM CCG

Comment 1. Project Summary, Page 5
AGR Vent Sequestration upon Startup

CCG is concerned about the definitiveness of the highlighted language in the following statement from the Project Summary regarding the implementation of carbon sequestration at the TEC: *"The CO_2 stream (from the AGR vent) would not be sequestered when the plant begins operation since the necessary prerequisites for sequestration would not be present."* We believe that all necessary prerequisites for sequestration are likely to be satisfied prior to the time that TEC begins commercial operation as it is our intent to meet the requirements of Illinois' Clean Coal Portfolio Standard Law ("CCPSL", 20 ILCS 3855/1-75, as amended by P.A. 95-1027, effective June 1, 2009). As the IEPA is aware, CCG is pursuing classification of TEC as a "clean coal facility" under the CCPSL. Pursuant to that law, CCG is required to capture and sequester at least 50% of its CO_2 emissions when the plant begins operation. If it fails to meet this standard for any reason whatsoever, CCG is subject to a penalty of $20 million per year, and additional penalties in the form of a reduction on its approved return on equity if such failure is deemed willful. While CCG agrees with IEPA that CCS does not meet the definition of Best Available Control Technology (BACT) for the purposes of TEC's PSD permit for all the reasons set forth in the Project Summary and the application, CCG nonetheless is committed to developing TEC as a clean coal facility with the objective and intent of sequestering the CO_2 when the plant begins operation.

The IEPA acknowledges this informational statement from CCG. This statement does not require any substantive response by the IEPA. This is because it simply restates CCG's intent to be a clean coal facility under the CCPSL and to sequester CO_2 if and as it would be possible do so, as would be required under the CCPSL.

Comment 2. Draft Permit Condition 3.4(a)
Revised Metallic HAP Potential Emission Calculations

Since the submittal of the Application,[664] CCG has reconsidered the methodology used for calculating potential emissions of metallic hazardous air pollutants (HAPs). As shown in Table C-22.2 of Appendix C to Volume 1 in the Application, the original metallic HAP emission calculations for syngas and for SNG-fired equipment relied primarily on site-specific emission factors derived from: 1) coal trace metals concentrations, 2) pollutant-specific coal-to-raw syngas conversion rates, and 3) syngas conditioning train removal efficiencies. To conservatively estimate potential HAP emissions for the project, CCG originally set the syngas conditioning train removal efficiency for all trace metals other than mercury to zero. On November 15, 2011, CCG submitted a comment letter to IEPA requesting a reduction in the plant-wide mercury emission limit in Condition 3.4(b) of the draft permit from 0.10 tpy to 0.01 tpy based on the expected mercury limit for IGCC units in the new NESHAP from Coal- and Oil-Fired Electric Utility Steam Generating Units (40

[664] General references to the permit application in this comment letter refer to the three volume "Updated Prevention of Significant Deterioration and State Construction Permit Application for the Taylorville Energy Center" submitted by Christian County Generation in the following three parts: 1) Volume 1 of 3 - Updated Permit Application submitted on September 24, 2010, 2) Volume 2 of 3 - Class II Area Air Quality Modeling Report submitted on October 14, 2010, and 3) Volume 3 of 3 - Greenhouse Gas Best Available Control Technology Analysis submitted October 27, 2010. In this comment letter, these application submittals are generally referred to as "the Application".

CFR 63 Subpart UUUUU).[665] In conjunction with reconsidering the mercury emissions from the TEC, CCG also feels it is appropriate to reconsider the conservatism built into the potential emissions calculations for other non-mercury metallic HAPs. As such, CCG has updated the trace metal emissions calculations presenting in Section C-22 and C-23 of Appendix C to reflect the use of a 90 percent syngas conditioning train removal efficiency based on the expected performance of the syngas processing train for removing metals from the sweet syngas and SNG (refer to Attachment A). Design specifications for the various types of syngas processing equipment located between the gasifiers and the outlet of the methanation unit suggest a significant amount of trace metals removal will occur, and this removal efficiency for trace metals should be accounted for when establishing the potential emissions from sweet syngas and from SNG-fired equipment at the TEC.

In addition, CCG is no longer relying on the AP-42 Chapter 1.4 external natural gas combustion emission factors for trace metals to calculate the potential emissions from the combustion turbines (CT) in instances where the AP-42 emission factors are higher than the site-specific emission factors (refer to Table C23.2 of Appendix C to the Application, where AP-42 emission factors were originally used for cadmium and chromium). These AP-42 Chapter 1.4 emission factors are no longer expected to be representative of the metallic HAP emission profile for the CTs. As discussed in Section 3.1.3.5 of AP-42 Chapter 3.1 for Stationary Gas Turbines, metallic HAP emissions found in turbine exhaust are a function of the fuel metals content. The natural gas that will be burned in the CTs is not known to contain measureable levels of trace metals as is evidenced by the lack of metallic HAP emission factors for gas-fired CCCTs in AP-42 Chapter 3.1 and by the fact that the potential natural gas suppliers for the site do not report trace metals in their gas analyses and do not expect these species to be present in their natural gas. Furthermore, an investigation into the basis of the metallic HAP emission factors reported in AP-42 Chapter 1.4 revealed that the large number of the individual test runs used as the basis for the emission factors had no detectable emissions. Therefore, trace metal emissions from natural gas combustion in the CTs are expected to be negligible, and as such, the annual potential emission calculations for the CTs presented in Table C-23.2 of Attachment A conservatively assume that SNG is burned continuously at the maximum hourly fuel heat input rate for the turbines. Accordingly, the revised metallic HAP potential emission calculations for the CTs presented in Attachment A use the site-specific SNG combustion emission factors developed from the coal metal concentrations, coal to raw syngas conversion rates, and the updated syngas conditioning train removal efficiency of 90 percent. The raw syngas combustion emission factors used in the TEC emission calculations (which do not account for any removal of trace metals in the syngas conditioning train) compare favorably with the trace metals stack test data for syngas-fired IGCC units reported for the recent Utility MACT information collection request issued by U.S. EPA; therefore, the TEC emission factors are expected to provide an accurate estimate for the potential trace metal emissions from raw syngas, sweet syngas, and SNG combustion.[666]

[665] Letter from Mr. Larry Carlson, Tenaska to Mr. Dean Studer, IEPA, RE: Public Comments - Taylorville Energy Center Draft Air Permit Christian County Generation, LLC - Application No. 05040027, November 15, 2011.
[666] U.S. EPA Technology Transfer Network, Air Toxics Standards for Utilities: MACT Floor-IGCC, March 16, 2011, available at http://www.epa.gov/ttn/atw/utility/utilitypg.html

For external combustion equipment capable of firing both natural gas and SNG (i.e., SRU thermal oxidizer, coal dryers, auxiliary boiler, flare pilots, and methanation startup heater), the metallic HAP emission calculations continue to rely on the higher of the AP-42 Chapter 1.4 emission factor or the site specific emission factor. CCG chose to retain the emission factors from AP-42, Chapter 1.4, for these external combustion sources at the TEC since this AP-42 section is based on stack test data specifically for boilers, process heaters, and furnaces which are expected to have similar combustion dynamics. While these AP-42 Chapter 1.4 emission factors are suspected to be biased high due to the large numbers of no detectable emissions results in the dataset, CCG has chosen to retain these emission factors in the HAP emission calculations for the TEC to ensure the conservatism of the plant-wide annual potential HAP emission estimated for the project. As discussed in Section 3.2.1 of the AP-42 Chapter 1.4 background document, metallic HAP stack test results with no detectable emissions were reported as one half of the detection limit for the purposes of calculating an emission factor even though there is no statistical evidence that the emissions of the measured trace metal are greater than zero, and therefore, the emission factors calculated using this approach are expected to be biased high.[667] Despite the uncertainty regarding the accuracy of the trace metal emission factors in AP-42 Chapter 1.4, it is common for applicants for permits for natural gas-fired external combustion equipment to use these data for calculating speciated and total HAP emissions.

The IEPA acknowledges this comment from CCG. As it constitutes an informational statement, it does not require any substantive response by the IEPA. This is because emissions of HAPs from the TEC, overall, are limited by Condition 3.4(a) to below major levels.

However, in conjunction with this statement, a change has been made to the emission limit for lead in Condition 3.4(a). In the issued permit, the limit is 0.02 tons/year, reduced from 0.22 tons/year in the Draft Permit. As discussed in this statement, the lower limit is more appropriate limit, as the power block would fire SNG and commercial, pipeline natural gas.

Comment 3. Draft Permit Condition 4.1.7-1(c)
Alternative Compliance Option for Flare Design Requirements in 40 CFR 60.18

CCG concurs with the current permit language regarding the alternative compliance option to 40 CFR 60.18 when flaring syngas, which is consistent with similar language incorporated into the PSD permit for the Kentucky Syngas site in Western Kentucky. CCG considered the alternative compliance option to be necessary and appropriate in light of the unique operating characteristics of syngas flares.[668] CCG is providing the following additional supporting information for the alternative compliance option to the flare design requirements in 40 CFR 60.18. 1) a technical paper authored by the John Zink Company entitled *An Experimental Analysis of Flame Stability of Open Air Diffusion Flames* (refer to Attachment B) and 2) a US EPA background document supporting the development of the hydrogen exemption in 40 CFR 60.18 entitled *Basis and Purpose Document on*

[667] Eastern Research Group for U.S. EPA Office of Air Quality Planning and Standards, *Emission Factor Documentation for AP-42 Section 1.4 Natural Gas Combustion*, March 1998
[668] Kentucky Division for Air Quality, Final Title V/PSD Air Quality Permit for Kentucky Syngas, LLC, September 24, 2010.

Specifications for Hydrogen-Fueled Flares (refer to Attachment B). As discussed in these documents, process gases containing primarily carbon monoxide and hydrogen, like syngas, exhibit high flame stability. These types of process gases can be burned over a wider range of velocities and heat content conditions than other organic process gases that are commonly flared without compromising the destruction/removal efficiency (DRE) achieved by the flare. As long as the features of a flare flame during a visual observation indicate stable combustion (i.e., no evidence of burn-out or separation between the flare tip and parts of the flare flame), a DRE at or above 98 percent for CO and VOM will be achievable on a continuous basis.

The IEPA acknowledges this informational statement from CCG, which does not require any substantive response by the IEPA. The statement provides additional information that supports the IEPA's permit decision with respect to flare.

Comment 4 Draft Permit Conditions 4.3.3-1(b)(i) and (c)(ii)
Applicability of NSPS Subpart Y PM Emission Limits to Coal Handling Sources

To clarify the applicability of the PM emission standard of the NSPS Subpart Y, in Condition 4.3.3-1(b)(i) and (c)(ii), to the emission units listed in Attachment 1 Table II of the permit, CCG requests that IEPA add a column to this table to indicate the applicability of the PM standard in this NSPS. In this regard, Condition 4.3.3-1(b)(i) applies to the coal milling and drying system stack that serves both coal dryer baghouses (EP21 in Attachment 1 Table II to the Draft Permit) since the coal dryers are classified as "thermal dryers" under the affected facility definitions in this NSPS. Condition 4.3.3-1(c)(ii) applies to various coal handling baghouses and bin vent filters listed in Attachment 1Table II as these fabric filters serve emission units that are considered "coal processing and conveying equipment" under this NSPS. Finally, Condition 4.3.3-1(c)(ii) also applies to the active storage dome baghouses (EP15), raw coal silo vents (EP19-20), gasifier coal bunker vents (EP22-23), and the off-spec coal silo vent (EP24) since these fabric filters serve emission units that are considered "coal storage systems" under this NSPS.

In addition to clarifying which units are subject to the PM standard of this NSPS, this change is also sought because, it will also clarify the units for which performance tests must be conducted for PM emissions pursuant to this NSPS, as addressed in the emission testing requirements in Condition 4.3.7-1(a) of the Draft Permit,

The IEPA will not make the change requested by this comment. This is because the provisions of NSPS Subpart Y determine to which "affected units" these NSPS standards apply.

Comment 5. Draft Permit Condition 4.3.7-1(a),(e), and (f)
Condensable PM Emission Testing for Fabric Filters for Material Handling Operations

Based on the language in Conditions 4.3.7-1(a) and 4.3.7-1(e), it appears that IEPA is requiring both filterable PM and condensable PM testing for the affected units subject to the NSPS Subpart Y-derived filterable PM emission limits in Conditions 4.3.3-1(b)(i) and 4.3.3-1(c)(ii). CCG does not believe that condensable PM emission testing for material handling fabric filters operated at ambient temperature is reasonable or appropriate, and CCG requests

that IEPA remove the requirement from the permit in accordance with the alternative set of permit revisions in Attachment E.

CCG's primary concern with IEPA's PM testing provisions for bulk material handling, drying, and storage equipment is that it requires condensable PM emissions testing for affected units associated with coal transport and storage operations that have ambient exhaust temperature and are not known to be sources of condensable PM emissions. Pursuant to 40 CFR 52.21(b)(50)(v), condensable PM emissions "include gaseous emissions from a source or activity which condense to form particulate matter at ambient temperature". An inherent assumption in this definition is that the exhaust from the source or activity is significantly above ambient temperature and above the boiling point of gaseous constituents that could comprise condensable PM. Therefore, by definition, baghouses with ambient temperature exhaust cannot be sources of condensable PM. The regulatory test method for quantifying condensable PM, Method 202, formalized the definition in the federal PSD regulations by stating "if the gas filtration temperature never exceeds 30°C (85°F), use of this method is not required to measure total primary PM".[669] Even on the summer days in Taylorville when the ambient temperature may exceed 85°F, the ambient temperature coal storage and handling fabric filters are still not expected to emit any condensable PM because there are no operating characteristics of these sources which would tent to form gaseous emissions that may condense into particulate upon cooling.[670] The lowest initial volatilization temperature of the volatile organic matter fraction of coal observed in the literature is approximately 250°C, which is much greater than the highest expected ambient temperatures at the facility.[671] In addition, EPA made the following statement in the preamble to the April 28, 2008 proposed amendments to NSPS Subpart Y with respect to condensable PM emissions for coal storage and handling sources other than thermal dryers:[672]

> We concluded that there are insignificant condensable PM emissions from coal processing and conveying equipment, coal storage systems, and transfer and loading systems and, therefore, decided not to establish a separate PM limit for condensable PM emissions.

As shown in Table C-2.1 of Appendix C to Volume 1 of the Application, the only NSPS Subpart Y affected sources subject to PM testing that have exhaust temperatures above ambient are the coal milling and drying baghouses (with an exhaust temperature of 214 ˚F) and the gasifier coal bunker vents (with an exhaust temperature of 160 ˚F). CCG does feel it is appropriate to quantify condensable PM emission from the coal milling and drying baghouses since these units are expected to be sources of condensable PM emissions formed as a byproduct of natural gas combustion in the dryer burners, but condensable PM testing for the gasifier coal bunker vents should not be required. The gasifier coal bunker vents are

[669] USEPA, Method 202 - Dry Impinger Method for Determining Condensable Particulate Emissions from Stationary Sources, Section 1.2(a), available at http://www.epa.gov/ttn/emc/promgate/m-202.pdf

[670] According to the National Climatic Data Center (NCDC) Local Climatological Data Annual Summaries for 1999 at the Springfield Capital Airport in Springfield, Illinois (KSPI), approximately 30 days per year on average have maximum daily temperatures above 90°F over the 30 year period of record.

[671] Kopp, O.C., and Harris, L.A., "Initial volatilization temperatures and average volatilization rates of coal - their relationship to coal rank and other characteristics," *International Journal of Coal Geology*, Volume 3, Issue 4, p. 333-348, April 1984, http://www.sciencedirect.com/science/article/pii/016651628490003X

[672] 73 FR 22901, Standards of Performance for Coal Preparation Plants

associated with coal storage systems that receive pneumatically conveyed coal from the coal milling and drying system. The coal from the dryers contains residual heat that causes the exhaust temperatures of the coal bunker vents to be elevated above ambient. Even at the moderate exhaust temperatures of the coal bunker vents, the coal is not expected to emit any gaseous compounds that could condense in the atmosphere as particulate as evidenced by USEPA's decision not to regulate condensable PM emissions from coal storage systems downstream of thermal dryers. Accordingly, CCG requests that IEPA remove all condensable PM testing requirements in Condition 4.3.7 except for an initial Method 202 condensable PM test for the coal milling and drying baghouse stack.

If IEPA nonetheless retains the condensable PM emissions testing for ambient temperature fabric filters in the permit, CCG request that IEPA revise Condition 4.3.7-1(a) to make it clearer that the PM testing requirement includes both filterable and condensable fractions. Condition 4.3.7-1(a) should be revised by indicating that both filterable and condensable PM emissions testing are required for the identified units and that filterable PM emissions testing must be conducted in accordance with the relevant requirements of 40 CFR 60.255. In addition, Condition 4.3.7-1(e) should be revised to indicate that only filterable PM_{10} and $PM_{2.5}$ emissions testing (conducted in accordance with Method 201 or 201 A) is required if the results of the filterable PM testing (conducted in accordance with Method 5) required in Condition 4.3.7-1(a) cannot be used to demonstrate compliance with the applicable PM_{10} and $PM_{2.5}$ emission limits in Attachment 1 Table II. Additional condensable PM testing for the purposed of quantifying total PM_{10} and $PM_{2.5}$ emissions is not necessary since all condensable PM has a size fraction smaller than $PM_{2.5}$ and the regulatory condensable PM test method, Method 202, is used to quantify the condensable fraction of total PM, PM_{10}, and $PM_{2.5}$.

Upon review of this comment, the IEPA agrees that exhaust gas temperature is a relevant consideration in determining whether testing is needed for emissions of condensable particulate and should be required. Accordingly, in response to this comment, in the issued permit, a minor change has been made to Condition 4.3.7-1(e). This condition now provides that testing for condensable particulate would only be required to be conducted if appropriate based on the temperature of exhaust gas in the stack of the emission unit. This would provide for such testing when the exhaust gas temperature of emission units involved in coal handling or processing is above ambient temperatures so that emissions of condensable particulate may be present. It would not require such measurements when the exhaust gas temperature is at ambient temperature so that condensable particulate would not be present, since any precursors to the formation of condensable particulate that may have been present upstream of the stack would have already transformed into condensable particulate.

The IEPA has not made the specific changes requested by CCG. This is because they requested changes to Condition 4.3.7-1(a). This condition addresses performance testing for PM emissions required by the NSPS Subpart Y. As this NSPS does not require testing for condensable particulate, that condition was not the appropriate place to address CCG's concerns. The appropriate condition in which to address the issue raised in this comment was Condition 4.3.7-1(e), which deals with emission testing

to verify compliance with permit limits for particulate, for which measurements of condensable particulate are relevant.

Comment 6. Draft Permit Condition 4.3.7-1(c) and (f)
Other Clarifications to PM Emissions Testing for Fabric Filters for Material Handling

Revisions need to be made to Conditions 4.3.7-1(c) and 4.3.7-1(f) to clarify the PM testing requirements for material handling sources. Condition 4.3.7-1(c) which specifies the testing requirements for the gasifier coal bunker vents does not need to address PM since the bunker vents are subject to a NSPS Subpart Y PM emissions limit and thus, the PM testing requirements are already addressed in Condition 4.3.7-1(a) (refer to Attachments D and E). Condition 4.3.7-1(f) should be revised to indicate that the NSPS Subpart Y performance testing requirements in 40 CFR 60.257 only apply to filterable PM, and the particulate matter test method list should be revised to more closely match the testing protocol that CCG would likely implement to comply with the requirements of the permit. Method 5 should be listed as a separate line item for filterable PM. Method 201 should be listed as the test method for filterable PM_{10} and Method 201A should be listed as the method for filterable PM_{10} and $PM_{2.5}$. Under this revised scheme of test methods, CCG could choose to conduct only a Method 5 filterable PM test and use the results to assess compliance with the applicable PM, PM_{10} and $PM_{2.5}$ emission limits based on the assumption that all filterable PM has a size fraction less than $PM_{2.5}$. If some type of PM speciation is deemed necessary, CCG could conduct a follow-up Method 201 and 201A test in accordance with Condition 4.3.7-1(e). If a Method 201 test is conducted, CCG would assume that all measured filterable PM_{10} falls below the $PM_{2.5}$ size fraction, and if a Method 201A test was conducted CCG would have both filterable PM_{10} and $PM_{2.5}$ for direct comparison against the applicable PM_{10} and $PM_{2.5}$ emission limits without the need for any simplifying assumptions regarding PM speciation.

These changes requested by CCG are not appropriate or necessary. This is a consequence of the change made to Condition 4.3.7-1(e), which does appropriately address the circumstances in which testing for condensable particulate is or is not required. In this regard, it should be noted that Condition 4.3.7-1(f) addresses the methods that must be used for emission testing but does not address the emission units and pollutants for which emission testing is required.

Comment 7. Various Draft Permit Conditions
Corrections to Typographical Errors

In Condition 4.2.10-1, references to Condition 5.3 and 5.3 should be changed to references to Conditions 6.2 2 and 6.3, respectively.

The permit contains two different conditions that are identified as Condition 4.1.10-2(b).

There is no condition "4.9.8."

These errors have been corrected, as further discussed in the "LISTING OF EDITORIAL CHANGES BETWEEN THE DRAFT PERMIT AND THE ISSUED PERMIT" at the end of this Responsiveness Summary.

Comment 8. Condition 4.2.2(b)(v)
Limit for CO_2 Emissions from the Combustion Turbines

CCG is requesting a revision to the combustion turbine CO_2 limit to make the terms of the limit consistent with USEPA's proposed Greenhouse Gas New Source Performance Standard (NSPS) for Electric Utility Generating Units (77 FR 22392, April 13, 2012). The CO_2 limit in the Draft Permit is based on the gross power output of the combustion turbine generators only, ignoring the output from the steam turbine generator (i.e., only the "simple cycle component") as compared to the proposed NSPS, which considers the gross power output (i.e., both the combustion turbine and steam turbine components). The CO_2 limit would be 827 lb/MW-hour when the power output from the steam turbine associated with operation of the heat recovery heat recovery steam generators on the combustion turbine is also taken into consideration. Therefore, CCG requests that the CO_2 limit in Condition 4.2.2(b)(v) be changed from 1201 lb/MW-hour (gross combustion turbine power output) to 827 lb/MW-hour (gross combined cycle output).

The new limit requested by CCG is included in the issued permit, accompanied by appropriate monitoring and recordkeeping requirements to address compliance with this new limit. (Changes to Condition 4.2.9-2(b)(i), new Condition 4.2.9-2(b)(ii), changes to 4.2.10(b)(v) and new Condition 4.2.10(d)(v).) In light of USEPA's recent proposal of an NSPS that would address emissions of CO_2 in terms of overall power output from both the combustion turbines and the steam turbine, it is reasonable for the permit to also include a limit in these terms. The limit that CCG has proposed is consistent with information in the application for the energy efficiency and CO_2 emissions of the combustion turbines considering they would be operating in a combined cycle configuration, with power also generated by an associated steam turbine.

However, the issued permit also retains the CO_2 limit for the combustion turbines from the Draft Permit. That is, this new limit does not replace the proposed limit but is established as an additional limit for the combustion turbines. This is because the "original limit" from the Draft Permit is also an appropriate limit for the combustion turbines. It was based on detailed information provided in the application and directly addresses the energy efficiency and CO_2 emissions of the combustion turbines when considered by themselves.

Comment 9. Condition 4.1.6
Requirement for CO_2 Sequestration

CCG wishes to follow up on our informal requests over the last two months regarding a permit limit reflecting use of carbon capture and sequestration ("CCS"). While CCG agrees with IEPA's proposed determination in the Draft Permit that CCS is not technically feasible as that term in used in Clean Air Act PSD permitting, CCG is now formally requesting an additional CO_2 limit for the AGR Unit based on the planned use of CCS when applicable law and regulation allows this, consistent with CCG's intent to develop and implement CCS for the TEC to the fullest extent possible.

The proposed new limit in Condition 4.1.6 would limit CO_2 emissions from the AGR Unit to 11.14 tons per million scf of substitute natural gas (SNG) produced by the gasification block, annual average, effective if certain criteria are met. This limit would represent a 90% reduction from the current limit and a 90% capture rate. The criteria for the effectiveness of this limit would be either: 1) When a pipeline and related facilities are available at the TEC site to deliver commodity CO_2 to a third party; or 2) 24 months after the later of the effective date of the Class VI UIC permit (and any other permits that may be required to implement CCS) and the date by which CCG has obtained the necessary storage and easement rights, provided that emissions that result from limitations on CO_2 injection under the terms of TEC's Class VI (or similar) permit shall not be included in this limit. Failure to obtain the necessary storage and easement rights, however, shall not excuse compliance with the proposed limit unless the State of Illinois, through the Department of Commerce and Economic Opportunity, has failed to provide the assistance necessary to procure such rights.

Even if IEPA determines not to issue the permit as requested, CCG is committed to the development and implementation of CCS for the TEC to the fullest extent possible. Once CCS has been established for the TEC (through the issuance of effective approvals and the acquisition of easements and storage rights needed for CCS, CCG will seek permit limits reflecting its operation to reduce the allowable CO_2 emissions from the plant.

The IEPA appreciates CCG's desire to memorialize its commitments to CCS by a concrete, quantitative provision in the permit. However, the IEPA will not include the condition now being requested by CCG in the permit that is now being issued. The various qualifications to the criteria in the proposed condition serve to confirm that there are significant hurdles that must be overcome before CCS can be implemented for the TEC in practice. They also suggest that events may occur during the life of the plant that would disrupt continued use of CCS. Accordingly, as already discussed, the permit that is now being issued cannot require CCS as a component of the BACT determination for the plant.

In addition, the qualifications to the criteria in the proposed condition involve subjects that are outside the established areas of expertise, responsibility and authority of the IEPA. Since the requested condition would be included in an IEPA permit and would necessitate exercise of reasoned judgment, rather than simple matters of fact, it would be improper and of questionable effect if the IEPA were to defer to others in deciding whether these qualifications were or were not satisfied. Accordingly, the requested condition cannot be considered enforceable as a practical matter and should therefore not be included in the permit that is now being issued.

In these circumstances, it is appropriate for the IEPA at this time to rely upon the provisions of the CCPSL as they would address use of CCS by the plant. The CCPSL provides economic incentives and penalties that should assure that CCG sequesters CO_2 from the plant as it is possible to do so. Moreover, as CCG is able to implement CCS for this plant and in the future seeks permit limits on CO_2 emissions that reflect the reductions in emissions that are achieved with CCS, the IEPA would welcome the opportunity to work with CCG to issue a permit in the future that contains such limits.

FOR ADDITIONAL INFORMATION

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

Bradley Frost, Community Relations Coordinator
Illinois Environmental Protection Agency
Office of Community Relations
1021 North Grand Avenue, East
P.O. Box 19506
Springfield, Illinois 62794-9506

217-782-7027 Desk line
217-782-9143 TDD
217-524-SO23 Facsimile

brad.frost@illinois.gov

LISTING OF SIGNIFICANT CHANGES
BETWEEN THE DRAFT PERMIT AND THE ISSUED PERMIT

Finding 1(c) – The portions of this finding providing the nominal sulfur and heat content of the design coal for the source were removed. These specifications were only intended to be part of an informational statement. However, it became apparent based on a comment that this information might be misconstrued as an enforceable requirement. To avoid this possibility, information for the composition of the design coal supply was removed from the finding.

Finding 3 – The location of the plant is now indicated as being in Taylorville. This change responds to a comment that the City of Taylorville had extended its boundaries so that this plant would now actually be located within the city.

Condition 3.4(b) – In the issued permit, the annual emission limits for lead and mercury are set at 0.02 and 0.01 tons/year, respectively, from 0.22 and 0.10 tons/year in the draft permit. This change was made in response to comments from CCG. The new limits reflects CCG's re-evaluation of the mercury content of the coal feedstock and removal efficiency data for syngas processing train, to develop more realistic data for the potential emissions of these pollutants.

Condition 3.4(d) – In the issued permit, this condition specifically requires monthly, as well as annual records of HAP emissions, and to require that this emission data be accompanied by supporting documentation and calculations. These comments were made in response to a comment that expressed concern about the practical enforceability of the limits on the plant's overall emissions of HAPs. The changes were made to enhance the enforceability of these limits by explicitly requiring data to enable annual limits to be "rolled" on a monthly basis and by explicitly requiring records of information that supports the recorded emission data.

Conditions 4.1.2-1(d)(ii)(B), 4.1.6(b) and 4.3.6(b) and (c) – In the issued permit, these conditions do not provide that certain annual emission limits would not become effective until one year after the shakedown of the gasification block is complete, as would have been provided by the Draft Permit. (In other words, these limits are now effective upon initial startup of the plant and its subsequent shakedown). This change was made in response to comment that triggered further consideration of these provisions in the Draft Permit. The IEPA has determined that annual emission limits for these units, as would have been addressed by the clause in question, should also be applicable during shakedown of the plant. It is not necessary to set alternative annual limits for shakedown of the plant.

Condition 4.2.2(b)(ii) – In the issued permit, this BACT limit for NOx emissions for the combustion turbines also applies during malfunction. This responds to comments that expressed concerns that, while there may be different BACT requirements for different modes of operation, BACT should apply at all times. Upon further consideration the IEPA determined that an alternative BACT requirement should not be set for the NOx emissions of the combustion turbines for malfunction events and that the BACT limits for periods of startup and shutdown of the turbines should not also apply for malfunctions. This is because the specific features of startup and shutdown that justify alternative limits for these periods should not be present during normal operation.

Condition 4.2.2(b)(v) – In the issued permit, an additional BACT limit has been added for CO_2 emission of the combustion turbines. The additional limit, 827 lb/MW-hour, addresses CO_2 emissions relative to the overall power output of the generators associated with the combustion turbines and the steam turbine in the power block, excluding the contribution to power output from the waste heat steam in the gasification block. This limit has been added in response to a request from CCG. It set another limit for the combustion turbines in the terms that are used by USEPA in its proposed NSPS for greenhouse gas for electric utility generating units.

Condition 4.2.4(a) – A clause was removed from this nonapplicability provision for the combustion turbines, "(see 40 CFR 60.49Da(b) for applicable exemption, which excludes CTs of an IGCC steam generating unit that are subject to 40 CFR 60, Subpart KKKK)." This clause was removed because it is not relevant to the determination that the combustion turbines are not subject to the NSPS, 40 CFR 60 Subparts GG and Da. The change was triggered by comments questioning the classification of the combustion turbines as natural gas fired turbines, rather than "integrated gasification combined cycle electric utility steam generating units," as defined by 40 CFR 60.40Da.

Condition 4.2.4(d) – A nonapplicability provision was added for the combustion turbines addressing the NESHAP for Coal- and Oil-fired Electric Utility Steam Generating Units, 40 CFR 63 Subpart UUUUU. This NESHAP is not applicable to the combustion turbines at this plant because the emission standards of this NESHAP do not apply to combustion turbines that fire natural gas. For purposes of this NESHAP, substitute natural gas (SNG) is a form of natural gas.

Condition 4.2.9-2(b) (i) (Draft Condition 4.2.9-2(b)) – In the issued permit, this condition also requires that the electrical output from the generator associated with steam turbine be monitored, as well as the output from the generators on each combustion turbine. This change was made to support the additional limit for the CO_2 emissions from the turbines that considers some of the output from the generator associated with the steam turbine.

Condition 4.2.9-2(b)(ii) – A condition was added requiring monitoring for steam flows to the steam turbine from the gasification block and either total steam flow to the turbine or steam flow from the heat recovery steam generators on the combustion turbines. These requirements were added to support the additional limit for the CO_2 emissions from the turbines that considers some of the output from the generator associated with the steam turbine.

Condition 4.2.10-2(b)(v) – A condition was added requiring daily records of electrical output generated from waste heat steam from the gasification block also be maintained. These requirements were also added to support the additional limit for the CO_2 emissions from the turbines that considers some of the output from the generator associated with the steam turbine, as well as the original limit that only considers output from the generators on the combustion turbines.

Condition 4.2.10-2(b)(v) – A condition was added requiring records of CO_2 emissions of the combustion turbines relative to electrical output of the generators. The requirements were added to support the "additional limit" for the CO_2 emissions from the turbines, as well as the "original limit."

Condition 4.3.2(d) (i) (Draft Condition 4.3.2(d)) – This condition was enhanced to further describe what wet dust suppression means for units TP1, TP2 and TP3. Namely, wet dust suppression shall

mean water spray for units TP1 and TP2, and dust (chemical) suppression for TP3 and PIL1 (the inactive coal pile). The change was made in response to comments that expressed concern for the lack of specificity in this requirement in the draft permit.

Condition 4.3.2(d)(ii) – A condition was added limiting the opacity of units controlled by wet dust suppression to 10 percent. This change was made in response to a comment that the Draft Permit, in fact, would not limit the opacity of the emission of these units to 10 percent, as indicated by the Project Summary. The new condition corrects this situation.

Condition 4.3.7-1(c)(i) – The requirement to test PM emissions of the coal bunker vent was removed from this condition, since testing for PM emissions, which is required by the NSPS, is already provided for by Condition 4.3.7-1(a). In the issued permit, Condition 4.3.7-1(c) would only address the further testing for CO and VOM emissions that is also required for the vent from the coal bunker. This change was made in response to a comment from CCG that sought further clarity regarding testing for PM emissions.

Condition 4.3.7-1(e) – This condition was clarified to only provide for emission testing for condensable particulate under conditions when condensable particulate may occur (i.e., when the flue gas in the stack is above ambient temperatures so that condensable particulate could be formed upon release to the atmosphere). The change was made in response to a comment from CCG that discussed the general nature of condensable particulate, pointing to elevated flue gas temperature in the stack, i.e., temperatures above the ambient temperature, air as a key factor in the presence or formation of condensable particulate.

Condition 4.8.6 – The VOM emissions of the methanol tank are limited to 0.21 tons per year, consistent with emission data in the application, rather than 0.25 tons per year as in the draft permit. This corrects an arithmetic error during the preparation of the draft permit. The new limit accurately reflects the relevant emissions data in the application (i.e., the sum of breathing and working losses, 0.11 tons per year, and landing losses, 0.10 tons per year). Related corrections were also made to Attachment 1, Table IV, which summarizes emissions plant-wide.

Condition 4.9.2(a)(ii) – The phrase “excluding A. above” was added to this provision, which defines the criteria by which a component is considered to be in VOM service so as to be subject to control with the LDAR program. The result of this change is that components in triethylene glycol service are subject to control with the LDAR program without regard to partial pressure of VOM in the material handled by the component or the operating pressure of the component. This change was made in response to comments that expressed concern about the specificity with which components that were subject to the LDAR program were defined.

Condition 4.9.6(c) – In the issued permit, sampling connections are also subject to the specified LDAR provisions for accessible valves. This corrects an inadvertent error in the draft permit. This change was made in response to comments that identified this oversight in the draft permit.

Condition 4.9.6(h) – In the issued permit, various corrections were made to these provisions that define leaks from components. The language in the draft permit did not specify that the 2000 ppm leak criterion for a damaged or leaking pump, compressor and agitator seals should apply to those components in light liquid and gas/vapor service. It also did not specify a 500 ppm leak for pump

and agitator seals in heavy liquid service. These changes were made in response to comments that expressed concerns about inconsistencies between the application and the requirement in the draft permit.

Condition 4.9.6(j) – In the issued permit, the required LDAR monitoring of components is to be conducted quarterly rather than annually. This change was made for consistency with the LDAR monitoring requirements upon which the relevant emission data in the application were based. This correction was made in response to a comment that identified this inconsistency between the application and the requirement in the draft permit.

Condition 4.11.5 – In this condition, which deals with the operating program for control of fugitive dust from roadways, the value for an example of a "trigger level" of opacity that would result in the implementation of additional dust control is 8 percent, rather than 12 percent. This corrects an inadvertent error in the draft permit. The trigger level for additional dust control measures must be lower than the applicable limit for opacity in Condition 4.11.2, which is 10 percent.

Attachment 1, Table I, Note b – A new note was added to this table which provides emission limits for the combustion turbines to provide the relevant definitions of the terms "startup", "cold start," "warm start" and "hot start." This change was made in response to a comment that observed that practical enforceability of emission limits for various types of startups required definitions for the various types of startups. The definitions in the permit are consistent with the terminology for different types of startups and associated emission data in the application. (Note: The previous Note b was renumbered Note c.)

Attachment 1, Table II –Hourly limits for $PM/PM_{10}/PM_{2.5}$ were added to the table for TP1, TP2, and TP3; the inactive coal pile and the slag pile maintenance.

Attachment 1, Table IV – In this summary of the plant's permitted emissions, the total permitted VOM emissions for storage tanks have been increased to 0.22 tons per year (from 0.12 tons per year). This corrects arithmetic errors during the preparation of Attachment 1, Table IV, in the draft permit. The total permitted VOM emissions of the plant (far right column) increase to 90.3 tons/year with this correction.

LISTING OF EDITORIAL CHANGES
BETWEEN THE DRAFT PERMIT AND THE ISSUED PERMIT

Table of Contents – The listing of conditions in Section 3 was corrected to include Condition 3.3, which was omitted from this listing in the draft permit.

Condition 4.1.8-2(a)(ii) – An incorrect cross-reference in this condition was corrected, from Condition 4.1.8-2(h) to 4.1.8-2(g).

Condition 4.1.10-1(d) – An incorrect cross-reference in this condition was corrected, from Condition 5.2(a) to 6.2(a).

Condition 4.1.10-1(e) – The numbering of this condition was corrected, from Condition 4.1.10(f) to 4.1.10(e), since the draft permit did not contain a Condition 4.1.10(e).

Condition 4.1.10-1(e) – An incorrect cross-reference in this condition was corrected, from Condition 5.2(b) to 6.2(b).

Condition 4.1.10-1(f) – The numbering of this condition was corrected, from Condition 4.1.10(g) to 4.1.10(f), since the draft permit did not contain a Condition 4.1.10(f).

Condition 4.1.10-2(b)(iv) – An incorrect regulatory citation in this condition was corrected, from 40 CFR 60.18(f)(1) to 40 CFR 60.18(c)(1).

Condition 4.1.10-2(c) – The numbering of conditions was corrected, by numbering the second Condition 4.1.10-2(b) in the draft permit to Condition 4.1.10-2(c) in the issued permit.

Condition 4.3.10(b)(iv) – An incorrect cross-reference in this condition was corrected, from Condition 4.3.6(b) to Condition 4.3.6(a).

Condition 4.9.5 – Errors in this condition in the draft permit for equipment components were corrected, i.e., the omission of CO_2 from the listing of pollutants for which limits were set and transposition of the limits for emissions of COS and methanol.

Condition 4.9.6(j) – An incorrect cross-reference in this condition was corrected, to Condition 4.9.6(b) from Condition 4.9.7(b).

Condition 4.9.7(a)(iv) – An incorrect cross-reference in this condition was corrected, to Condition 4.9.6(b) from Condition 4.9.7(b).

Condition 4.9.8 – The numbering of this condition, which was shown as Condition 4.9.9 in the draft permit, was corrected (i.e., there was not a Condition 4.9.8).