SUNCOKE ENERGY
SOUTH SHORE FACILITY

RESPONSE TO SITING BOARD STAFF'S FIRST DATA REQUEST TO SUNCOKE ENERGY SOUTH SHORE LLC

Prepared for:
SunCoke Energy South Shore LLC
1011 Warrenville Road, Suite 600
Lisle, Illinois 60532

SunCoke Energy

Prepared by: URS

525 Vine Street, Suite 1800
Cincinnati, Ohio 45202

Case #: 2014-00162

December 2014

COMMONWEALTH OF KENTUCKY

BEFORE THE KENTUCKY STATE BOARD ON
ELECTRIC GENERATION AND TRANSMISSION SITING

In the Matter of:

APPLICATION OF SUNCOKE ENERGY SOUTH SHORE LLC FOR A CERTIFICATE TO CONSTRUCT AND OPERATE A MERCHANT ELECTRIC GENERATING FACILITY AND A 138KV NONREGULATED ELECTRIC TRANSMISSION LINE IN GREENUP COUNTY, KENTUCKY	)	CASE NO. 2014-00162

RESPONSE TO SITING BOARD STAFF'S FIRST DATA REQUEST TO SUNCOKE ENERGY SOUTH SHORE LLC

Comes the Applicant, SunCoke Energy South Shore LLC ("SunCoke"), and for its Response to the Siting Board Staff's First Data Request (the "Staff's First Request"), states as follows:

GENERAL OBJECTIONS

1. Applicant objects to the Staff's First Request to the extent it seeks information, documents, or things not in Applicant's possession, custody, or control, or that are publicly and easily available to the Kentucky State Board on Electric Generation and Transmission Siting (the "Board").
2. Applicant objects to the Staff's First Request to the extent it seeks information which is outside the scope of the jurisdiction of the Board.
3. Applicant's Response to the Staff's First Request is hereby made without waiver and intentional preservation of:
    a. All questions as to the competence, relevance, materiality, and admissibility of evidence for any purpose of the information or

documents, or the subject matter thereof, in any aspect of this or any other court action, or judicial or administrative proceeding, or investigation;

b. The right to object on any grounds as to the use of any such information or documents, or the subject matter thereof, in any aspect of this or any other court action, judicial or administrative proceeding, or investigation;

c. The right to object at any time for any further response to this or any other request for information or production of documents; and

d. The right at any time to supplement this response.

4. Applicant objects to the disclosure of confidential commercial, business, or proprietary information. Applicant will produce responsive documents containing confidential commercial, business, or proprietary information subject to an appropriate order by the Board or a court of competent jurisdiction. If such documents are in the possession of the Applicant they will be specifically noted in the attached Response.

5. Applicant reserves the right to amend, correct, or supplement any and all parts of its Response herein, and further states that the information provided to the Staff's First Request has been prepared by the Applicant after reasonable investigation and preparation as of the date of this Response.

6. Applicant objects to the Staff's First Request to the extent it is unreasonably vague, overly broad, unduly burdensome, or purports to require the disclosure beyond the scope of this proceeding.

7. Applicant objects to the Staff's First Request to the extent it is unreasonably repetitive, overlapping, or duplicative.

8. By making general and specific objections, Applicant does not waive other objections that might be applicable or become applicable at some time in the future. Applicant expressly reserves the right to assert additional objections which may become apparent in the course of providing information or documents.
9. Applicant, by and through its Director of Business Development for North America, David Schwake, provides its Response to the Staff's First Request. Mr. Schwake has been responsible for gathering and overseeing the preparation of responses in the attached document entitled, *Response to Siting Board Staff's First Data Request to SunCoke Energy South Shore LLC*, and has directed the compiling of responses by persons under his authority and direction. The information contained therein is true and correct to the best of his knowledge and belief, and is incorporated into this pleading as if set forth fully and completely.

VERIFICATION

I, David Schwake, Director of Business Development for North America, SunCoke Energy South Shore LLC, certify that I have read the attached Response to Staff's First Data Request and the same is true and accurate based upon my best knowledge, information, and belief.

David Schwake
Director of Business Development – North America, SunCoke Energy South Shore LLC

COMMONWEALTH OF ILLINOIS)
) :S
COUNTY OF DuPage)

The foregoing instrument was acknowledged before me this 10th day of December, 2014, by David Schwake, Director of Business Development for SunCoke Energy South Shore LLC.

My Commission expires: 09/04/2017.

NOTARY PUBLIC
State at Large

OFFICIAL SEAL
RITA M SLAGER
Notary Public - State of Illinois
My Commission Expires Sep 4, 2017

Respectfully submitted,

George L. Seay, Jr.
Max Bridges
WYATT, TARRANT & COMBS, LLP
250 West Main Street, Suite 1600
Lexington, KY 40507-1746
859.233.2012

Counsel for Applicant, SunCoke Energy South Shore LLC

CERTIFICATE OF SERVICE

This is to certify that the original and ten true and correct copies of the foregoing have been filed in the office of the Kentucky State Board on Electric Generation and Transmission Siting, 211 Sower Blvd., Frankfort, Kentucky 40601 and that the following have been served via Federal Express on this the ____ day of December, 2014:

Hon. Quang D. Nguyen
Division of General Counsel
Assistant Director
211 Sower Blvd
P.O. Box 615
Frankfort, KY 40602-0615
Telephone: (502) 564-3940, ext: 782-2586

George L. Seay Jr.

George L. Seay, Jr.
Counsel for Applicant, SunCoke Energy South Shore LLC

61272341.1

LIST OF FIGURES

Figures

LIST OF EXHIBITS

Exhibits

RESPONSE TO SITING BOARD STAFF'S FIRST DATA REQUEST
TO SUNCOKE ENERGY SOUTH SHORE LLC
DATED DECEMBER 1, 2014

1. Refer to the Application, Section 2.4 — Proposed Radial Tie Line, page 5. In the third paragraph, it states, "The remaining portion of the line would be located in Ohio and would cross over a highly-developed and disturbed area before terminating at the AEP Millbrook Park substation." Explain what is meant by "high-developed and disturbed area."

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

While SunCoke specifically objects to this request for information about property in Ohio, which is outside the jurisdiction of the Kentucky State Board on Electric Generation and Transmission Siting (the "Board"), SunCoke will nonetheless comply in order to cooperate with the Board's request. The Ohio side radial tie line routing as indicated in Figure 7 of the Application would traverse property belonging to Infra-Metals, a fabricator and distributor of structural steel. This site was entered into the Ohio Environmental Protection Agency's (OEPA) Voluntary Action Program and ultimately received a Covenant Not to Sue (CNS) from the OEPA. Certain activity and use limitations on the Infra-Metals property, such as restricting the property to commercial or industrial land uses, were a condition of the issuance of the CNS. In addition to the Infra-Metals property, the line would traverse a flood wall, Norfolk and Southern Rail, and portions of the American Electric Power properties on approach to the AEP substation.

2. Refer to the Application, Section 6.0 — Public Involvement Activities, page 17. The first and last bullets on this page refer to formal responses made to the U.S. Army Corps of Engineers and the Kentucky Division of Air Quality, respectively. Provide a copy of the responses.

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

SunCoke specifically objects to this request because it is outside the Board's jurisdiction. Notwithstanding the foregoing, formal comment responses to the U.S Army Corps of Engineers and commenting parties are provided as **Exhibit M,** and the formal comment responses to the Kentucky Division of Air Quality are provided as **Exhibit N**.

3. Refer to the Application, Exhibit A — Property Survey Map. The property for SunCoke is referred to as the John R. McGinnis et-ux property and part of the Kathy Reid property in the title to the map.

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

a. Has SunCoke purchased any of the property? If so, submit a copy of the deed.

No, SunCoke has not yet purchased any of the property.

b. Does SunCoke have a contract with either or both parties for an intent to purchase? If so, submit a copy of each contract.

SunCoke has executed options for purchase with both parties. To the extent the request seeks production of the full option agreements, SunCoke specifically objects to this request because the option agreements are non-public confidential business information. However, in order to cooperate with the Board's request and confirm that SunCoke does have option agreements for these properties, SunCoke will produce copies of the applicable Memorandums of Option for each property as **Exhibit O** as soon as practical**.**

4. Refer to the Application Exhibit A — Property Survey Map. There is a reference to an adjacent property as "Commonwealth of Kentucky, D.B. 264, PG. 105."

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

a. Submit a copy of the deed for "Commonwealth of Kentucky, D.B. 264, PG. 105."

A copy of the deed is attached here as **Exhibit P.**

b. *Submit a map from the Greenup County Property Valuation Administrator (or a map using their GIS data for parcels), which includes U.S. 23 and the parcels directly across U.S. 23 from SunCoke's parcel. Include the owner names and tax parcel numbers.*

See **Figure 8** - Greenup County Parcels South of Proposed SESS Facility.

c. *The boundary line between the Commonwealth of Kentucky and SunCoke's property is referred to as a "R-O-W LINE." Is the Commonwealth of Kentucky the owner of the right of way for U.S. 23?*

The Commonwealth of Kentucky acquired a fee simple title for a portion of the U.S. Highway 23 roadway by deed from John McMahan, a copy of which is attached here to as **Exhibit P**.

d. *How wide is the right of way for U.S. 23?*

According to the Kentucky Transportation Cabinet (KYTC) as-built plans for U.S. Highway 23, included as **Exhibit Q,** the ROW is 120' from the center line of U.S. Highway 23 and approximately 70' from the edge of pavement.

5. *Refer to the Application, Exhibit B1 — Letters to Property Owners.*

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

a. *A letter was sent to Paul Don Gibson and Kimberly G. Gibson. Why was a letter sent to the Gibsons?*

A letter was sent to Paul Don Gibson and Kimberly G. Gibson because they own the property adjacent to the Siloam parcel on the east, which is on the southern side of the CSX Railroad track, having acquired title from Scott Williams, et al., by deed dated September 25, 2009 and recorded in Deed Book 556, Page 40, a copy of which is attached as **Exhibit R**.

b. *A letter was sent to Anna M. Neal. Why was a letter sent to Ms. Neal?*

A letter was sent to Anna M. Neal, formerly known as Anna Michelle Warnock, because she has an interest in the Siloam land parcel by virtue of a deed from Frank H. Warnock and

Matthew J. Warnock, Trustees for Frank H. Warnock, et al., dated December 30, 1994 and recorded in Deed Book 577, Page 73, a copy of which is provided as **Exhibit S.**

c. *Why were no letters sent to adjacent property owners Jimmie and Verna Williams and John McMahon (see Exhibit A — Property Survey Map)?*

No letter was sent to John C. McMahan because he is no longer an adjacent property owner. John C. McMahan and Norma Lee McMahan, his wife, conveyed a parcel to Paul D. Gibson by deed dated March 8, 1991 and recorded in Deed Book 392, Page 356, a copy of which is attached as **Exhibit P**. The references to Jimmie and Verna Williams and John McMahan on the Property Survey Map (Exhibit A to the Application) are in error, and a corrected copy reflecting the Gibsons' ownership interest in those parcels, is attached as **Exhibit BB**.

6. Refer to the Application, Exhibit C1 — Confirmation of No Ordinances for Zoning. Provide signed and notarized copies of the affidavits.

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

Fully executed and notarized copies of the affidavits are provided as **Exhibit T.**

7. Refer to the Application, Exhibit E3 — Public Meeting Presentation, page23. This page shows that customer commitments were expected to be secured in late 2014. Provide the status of SunCoke's efforts to secure customer commitments.

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

SunCoke continues to meet with customers on a regular basis surrounding potential coke supply from the proposed South Shore Kentucky plant. As was discussed during the public meeting, the expectation of securing customer commitments in late 2014 was presented only as part of a "potential" schedule, as noted in the slides presented at the meeting, and at that time represented SunCoke's best estimate. Moving forward with the plant still depends on securing customer commitments which SunCoke continues to pursue but over which SunCoke does not have direct control.

8. *Refer to the Application, Exhibit E3 — Public Meeting Presentation, page 24.*

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

a. *This page shows that the construction period will average over 500 workers with a projected peak of over 900 workers. Section 10.0 — Local Economic Impact, page 21, of the application states that there will likely be 400 workers during construction with a peak of approximately 600 workers. Explain the discrepancy and state which is accurate.*

SunCoke utilized prior heat recovery coke plant construction manpower loadings as an estimate for purposes of the July 8th, 2014 public meeting presentation. However, as the schedule has continued in development, we now expect a longer schedule driven by longer lead times for the delivery of major equipment. Therefore, due to the longer schedule, there is a lower average manpower loading and a lower peak manpower loading. The estimates were adjusted for the October 24th, 2014 Application, based on the best available information at that time, to reflect an average of 400 workers with a projected peak of approximately 600 workers. Essentially, SunCoke expects a comparable number of hours to be worked, but over a longer period of time. More accurate manpower loadings are not possible until the project schedule, construction design, and major equipment suppliers are finalized, but the numbers set forth in the Application represent the most accurate estimate SunCoke has to date.

b. *This page states that annual salaries will be over $7 million. Section 10.0 — Local Economic Impact, page 21, of the application states that wages and benefits will be approximately $9 million. Explain the discrepancy and state which is accurate.*

The $7 million includes only wages, whereas the $9 million includes both wages and benefits. Both numbers are correct based on current estimates.

c. *This page states that "[u]p to 50% of the coal charge may be Kentucky metallurgical coals." State whether it is possible that no Kentucky coal will be used.*

Due to market forces, reliability of coal supply and coal quality, logistics, customer requirements, and other forces beyond SunCoke's control, coal sourcing is always subject to change, and SunCoke cannot at this time commit to whether or how much Kentucky coal could potentially be used.

9. Refer to Exhibit H — Site Assessment Report ("SAR"), Section 1.2 — Surrounding Land Uses, pages 2-3, which states, "Access to the subject property is via Johnson's Lane along the eastern boundary and via a drive off of Route 23 along the southern boundary."

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

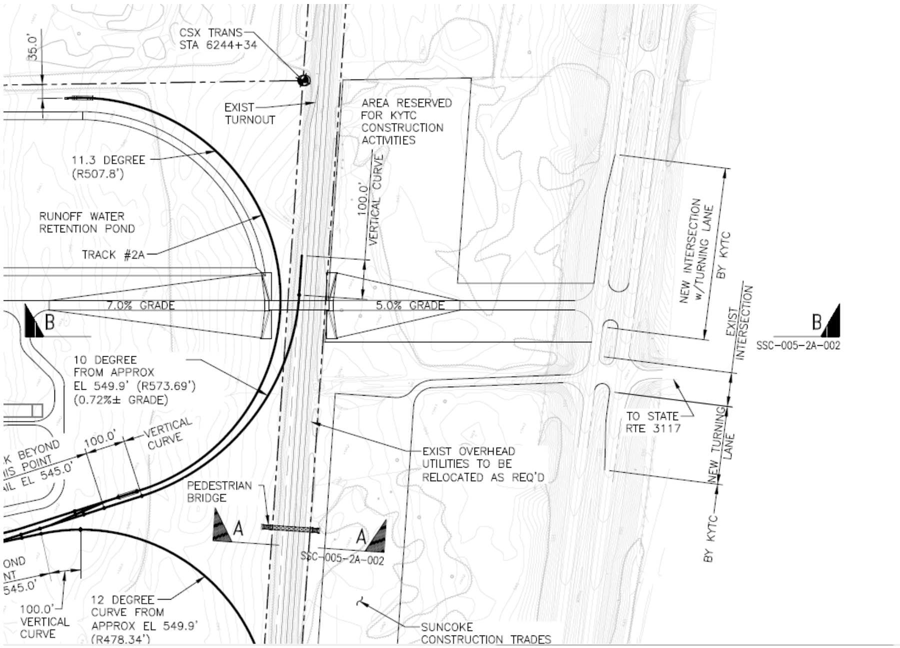
a. Provide a description of Johnson's Lane.

As indicated in Exhibit A – Property Survey Map of the Application, Johnson Lane is a county road with a 50-foot right-of-way beginning at U.S. Highway 23 and extending north to the United States of America's flowage easement of the Ohio River, a distance of approximately 5,500 feet.

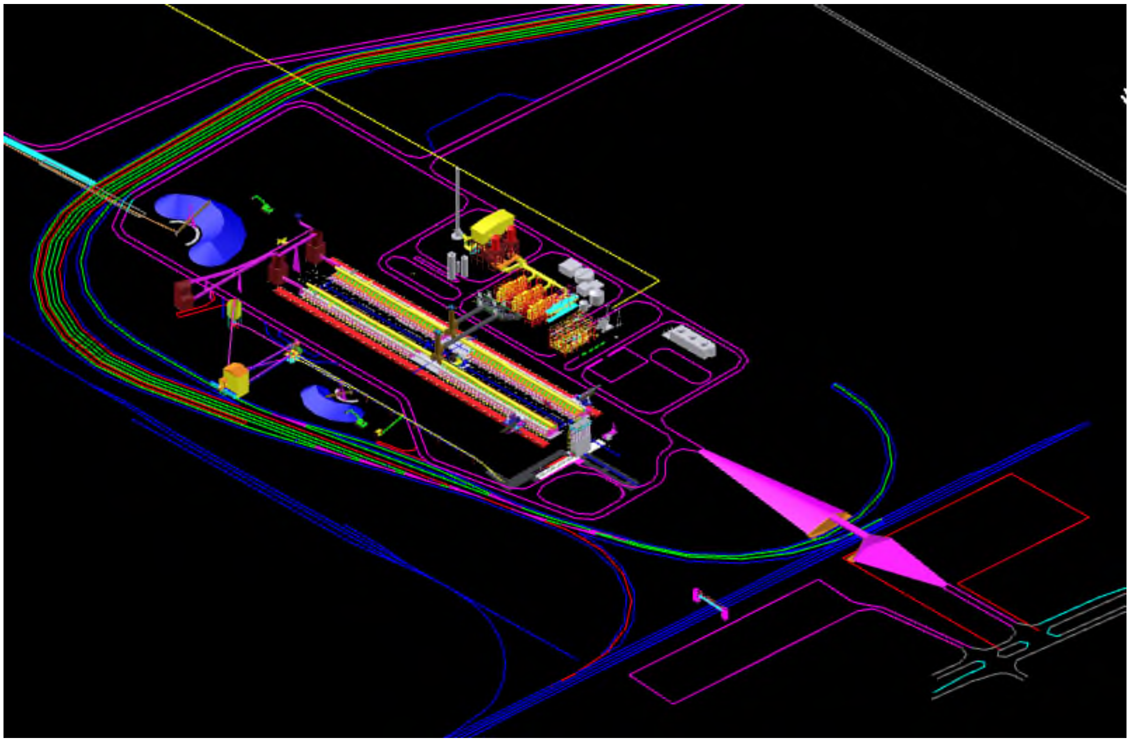
b. Provide a description of the drive off of Route 23 along the southern boundary that will provide access to the subject property.

SunCoke received information from the KYTC in preliminary discussions about an overpass, but design work has not started. Funding for the overpass has not been identified and will not be identified until such time as there is a commitment from SunCoke to build and operate the facility as proposed to the Kentucky Economic Development Cabinet. SunCoke utilized the preliminary information in its general arrangement of the plant consistent with typical guidelines of CSX and the KYTC.

Below is an image depicting the general arrangement layout utilized for the entrance access to the plant:



Below is an image indicative of the general arrangement showing the location of the bridge overpass:



c. *Refer to Exhibit H — SAR, Exhibit H5 — Summary of Rail Impact Considerations — Rail, Road & Logistics Review Meeting (Minutes of Meeting), dated September 27, 2013, page 4. Section 4 describes improvements to Johnson's Lane.*

(1) Does SunCoke intend to widen Johnson's Lane in the manner described in this section?

Yes, where possible.

a. *If so, will Greenup County conduct the actual construction in widening Johnson's Lane?*

Yes, the county road would be widened, targeting 12 feet per lane and 2 feet of gravel shoulder where possible. The road may be temporarily widened using gravel or other suitable surface during construction. See **Exhibit U** for a letter from Judge Executive Robert Carpenter in which he indicates the Greenup County Road Department would build a temporary road to bypass the Graf Brothers' lumber yard so as not to interrupt the Graf Brothers' operations during construction of the SESS facility. Once use of the temporary road begins, the Greenup County Road Department will commence the widening and ultimate improvement of Johnson Lane.

b. *Who will fund this construction?*

Based on the letter provided by Judge Executive Carpenter **(Exhibit U),** the Greenup County Road Department would fund the construction.

c. *Provide a timeline for this construction.*

Based on conversations with the Greenup County Road Department, it was estimated by the Greenup County Road Department that the project would take two to four weeks of construction. SunCoke would provide adequate (~30 day) notice for construction to be complete in time for use.

(2) On page 5 of this section, under 4.6, it states "Should it be decided that the existing width is not sufficient, SunCoke will need to address it with KYTC." Does "KYTC" refer to the Kentucky Transportation Cabinet? Does SunCoke intend to widen Johnson's Lane in the manner described in this section?

Yes, under the same section on Page 5, under 4.5, there is a reference to the Kentucky Transportation Cabinet (KYTC) (a.k.a. Kentucky Department of Transportation, a.k.a. Kentucky Highway Department). These are in reference to whoever is responsible for setting the requirements (i.e. U.S. Highway 23).

SunCoke intends to widen Johnson Lane in order to allow for two-way traffic. The details associated with widening from the railroad crossing south towards U.S. Highway 23 have not yet been discussed.

d. *Provide a projection of the volume of truck traffic along the southern portion of Johnsons Lane (between the rail crossing and U.S. Highway 23).*

The site is situated such that SunCoke could receive materials and equipment by road, rail, or river. SunCoke presently expects the larger equipment to be shipped in modules by river which should reduce truck traffic compared to prior plant construction. The bulk of truck traffic is expected for the delivery of concrete, aggregate, brick, and equipment. The construction team estimates, based on best information available to date, an average load of 50 trucks per day versus an approximate average of 11,800 vehicles per day which travel the stretch of U.S. Highway near the proposed site, according to the KYTC Traffic Station Counts for Greenup County **(Appendix R)**.

During the earlier stages of the construction, for approximately 6 to 8 months, the peak loading would occur on the order of 100 trucks per day. This is where the site is being cut and filled to bring the site to grade, pilings for foundations are required, concrete for foundations is required, and aggregates for roadways and other purposes are required. Once this peak period ended, the level would drop towards the average of 50 trucks for the next four to six months and then drop again to roughly 20 to 30 trucks per day for the balance of the project construction schedule. There are multiple factors affecting this potential traffic flow which have not yet been finalized, including but not limited to the volume of larger size modularization which would utilize barging as opposed to trucks, whether or not any delivery by rail would be utilized (potentially requiring earlier completion of a portion of the rail spur), staged delivery times based on suppliers' delivery schedules, actual equipment supply points, and other logistics details.

As stated above, SunCoke intends to utilize Johnson Lane, a public roadway, for receiving materials by truck during the construction phase. However, SunCoke would use commercially reasonable efforts to mitigate traffic flow issues on Johnson Lane by taking steps such as assessing other viable delivery methods, utilizing traffic control measures, notifying Graf Brothers of higher expected traffic flow periods, and scheduling deliveries around peak traffic times where practical.

As indicated in the application, SunCoke has already worked to mitigate the impacts to Johnson Lane by relocating the bridge overpass onto the proposed project site which consumes a significant amount of real estate. Additionally, SunCoke has added to the project's scope a construction parking lot and pedestrian bridge for the majority of the construction contractors.

10. Refer to Exhibit H — SAR, Section 1.4 — Proposed Access Control.

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

a. Describe, in more detail, planned access control and security at the site during construction to handle the large volume of temporary workers and material shipment.

The project site would be fenced to prevent unauthorized access during the construction phase of the project. Access is anticipated to be limited to three access points:

The first would be the pedestrian turnstile expected to be located at the southern portion of the project site near the planned parking lot for the construction labor force. This gate would be monitored by a security team. Access would be limited to employees with ID badges only. All hiring is expected to take place off site, so all employees entering at this location would have the required personal ID badge to enter. All employees entering the site would be tracked by a method to be determined so that the site safety and security teams could monitor who is on site at all times in case of emergency.

The second access point is anticipated to be the site vehicle gated entrance located off of the north end of Johnson Lane (north of Graf Brothers access). This location would be monitored 24/7 by security who would monitor vehicles and personnel entering and exiting the project site using the same methodology as the pedestrian turnstile. The badging system used at the man gate would be used to track employees at the vehicle gate. Equipment and material delivery personnel would sign in and be inspected for safety prior to being allowed to enter the main site.

A third limited access gate is anticipated to be located on the haul road leading to the river where large modularized equipment pieces would be unloaded from barges and moved to the site. This gate would be locked and monitored 24/7 to prevent unauthorized people from entering the project site. Everyone passing through this gate would have entered initially through one of the first 2 access points. **Exhibit W** includes the conceptual fencing and access plan.

b. How would access to the gates be controlled?

The site would be gated with 24/7 security monitoring during construction and operation. For the safety of employees and residents it is within SunCoke's best interests to protect the site by means of fencing, controlled access points, and continuous monitoring of the site either through turnstiles or vehicle gates. Vehicle gates would be controlled by personal identification badge access with automated control as well as manually by the 24/7 security personnel monitoring at the gate's guard shack. Employees and contractors would have identification badges to gain access to the site.

c. How would the gates be monitored?

Vehicle gates would be controlled by personal identification badge access with automated control as well as manually by the 24/7 security personnel monitoring at the gate's guard shack.

d. How would authorized personnel be identified?

Personal ID badges would be utilized for employees and contractors. Only authorized personnel would be granted access. Visitors and delivery drivers would be logged in by security personnel and escorted by an employee.

e. Provide clarification of the basis or rationale for the proposed methods for controlling access to the site. For example, do these reflect SunCoke's standard corporate policy or a security assessment that SunCoke may have conducted?

These proposed methods reflect SunCoke's standard operating practices.

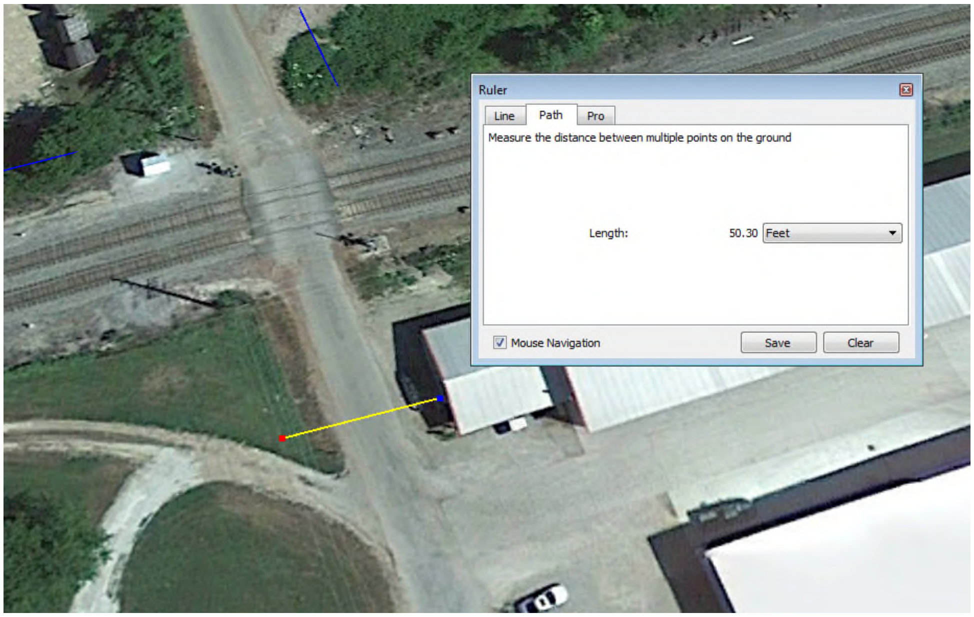
11. Refer to Exhibit H — SAR, Section 1.4 — Proposed Access Control.

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

a. Was Graf Brothers concerned about the potential increased traffic on Johnson's Lane that could occur because of the bridge overpass? If so, explain in detail.

It is SunCoke's understanding that increased traffic was not the leading cause for concern to the Graf Brothers, but rather the impact of the initially-proposed bridge overpass on existing Graf Brothers buildings, as the overpass would have utilized the entire Johnson Lane right-of-way. Graf Brothers has utilized up to (and possibly onto) the right-of-way which would have created access issues for Graf Brothers to its existing structures. The bridge overpass, due to the maximum grade allowable, requires a long entrance and exit ramp which, even if minimized by use of a retaining wall versus an embankment, could have created access restrictions utilizing the initially-proposed location. For example, as depicted in the image below, garage doors on one of the Graf Brothers' buildings open directly onto the right-of-way where the overpass retaining wall would have been placed.



In response to Graf Brothers' concerns, SunCoke relocated the bridge overpass onto SunCoke's property. The current general layout for the bridge overpass is depicted with the yellow oval on the western (left) portion of the photo below, compared to the original design, indicated with the yellow oval on the eastern (right) portion.

b. Has Graf Brothers expressed concern regarding the anticipated use of Johnson's Lane during the construction and operation of the proposed facility? If so, explain in detail.

During the public meeting held in July 2014, Graf Brothers expressed concern about the potential impact on traffic on Johnson Lane, and SunCoke discussed the ways in which it has worked to minimize this impact. Specifically, SunCoke would incorporate a contractor parking lot and pedestrian walkway onto SunCoke's project site to be utilized during construction. As discussed above, SunCoke has also relocated the bridge overpass directly onto the project site. SunCoke does intend to utilize Johnson Lane, a public roadway, for receiving materials by truck during the construction phase. However, SunCoke would use commercially reasonable efforts to mitigate traffic flow issues on Johnson Lane such as assessing other viable delivery methods, utilizing traffic control measures, notifying Graf Brothers of higher expected traffic flow periods and scheduling deliveries around peak traffic times where practical.

c. Has SunCoke attempted to develop an agreement with Graf Brothers to coordinate traffic and use of Johnson's Lane during construction and operation of the proposed facility? If so, provide a description of that agreement and, if it has been reduced to writing, provide the agreement.

No, as indicated above, SunCoke responded to Graf Brothers' concerns raised during the public meeting, but SunCoke and Graf Brothers have not discussed a formal agreement at this time. Until the project is finalized, there is not yet enough information to put such an agreement in place. However, as indicated, SunCoke will continue to use commercially reasonable efforts to mitigate traffic issues on Johnson Lane keeping in mind this is a county road (public roadway).

12. Refer to Exhibit H — SAR, Section 1.9 — Evaluation of Noise Levels, and Section 4.0 — Anticipated Noise Levels at Property Boundary. Provide an explanation of the rationale behind the locations selected for noise measurement and the propagated noise level locations.

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

Exhibit H1 contains noise studies conducted in Middletown, Ohio at a comparable SunCoke coke plant which uses the same heat recovery to electricity process utilizing steam turbine generators. The Middletown plant noise studies are considered relevant to the proposed South Shore, Kentucky plant due to similar construction and operations. In actuality, the Middletown noise studies are likely conservative for purposes of this Application. The noise receptor locations in the Middletown study (consisting of local roadways and nearby residential neighborhoods) are generally closer to the Middletown facility than the distance between the proposed South Shore plant and the closest residential neighborhood (where the background noise levels were tested for this Application). Exhibit H1 contains several layout maps indicating where the noise measurements were taken within the Middletown facility and the surrounding roadways for Middletown. These include the roadways adjacent to the closest neighboring communities as well as multiple points within the facility. The following table was generated from the noise data in Exhibit H1 along with estimated distances for reference:

Reference Point	Approximate distance to closest operating point	July 2010 Background	July 2010 During Construction	January 18th 2011 Background	January 18th During Construction	January 19th 2011 Background	January 19th During Construction	September 2011 Daytime Operation	September 2011 Evening Operation	Avg Background	Avg Construction	Avg Operation
R1	300	75	65	48	49	64	55	55	61	62	57	58
R2	1650	77	46	65	54	53	47			65	49	
R3	1700	61	49	61	50	73	65	55	56	65	55	56
R4	1450	63	64	63	58	59	56	67	56	62	60	62
R5	1450	56	46	60	54	59	51	60	57	58	51	59
R6	1300	46	46	42	37	46	40			45	41	
R7	1900	51	46	63	59	68	61			61	55	
Average	1393	61	52	57	52	60	54	59	58	60	52	58

The data indicates average background noise levels in the range of 45 dBA to 65 dBA, with average construction noise levels in the range of 41 dBA to 60 dBA, with average operating plant noise levels 56 to 62 dBA (for the data points collected). The data clearly indicates no impact to noise levels from plant construction or operation versus the background noise level.

Additionally, since receiving the request for information, SunCoke contracted McCulley, Eastham & Associates, Inc. (MEA) Industrial Hygiene Division to conduct a background noise level study at two locations in South Shore at the closest residential neighborhood (referenced as Sand Hill in the BBC report) which is attached as **Exhibit X.** The two locations, Monitoring Point A and Monitoring Point B, where the background noise data was collected in the South Shore noise study, were located directly to the north of the Sand Hill community along State Route 3117. The noise data indicates a very similar range to Middletown with the average background noise level at roughly 60 dB. The similar background noise levels indicate little cause for concern regarding noise impacts as stated in BBC's Review and Evaluation Report.

13. Provide an explanation of the type of noises that may arise outside of normal operations, including but not limited to safety whistles that sound during the opening of the coke ovens, the frequency with which these noises occur, and how loud these noises will be.

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

The facility's machinery, including the pusher charger machine, flat push hot car, and quench car operate during the production cycle. Warnings using intermittent flashing lights and audible tones (similar to sirens) are utilized for personnel safety during the 10-12 hour production cycle. The Middletown noise study indicates a noise level near the oven locations where machinery is operating in the 70 dBA range during production.

14. Refer to Exhibit H — SAR, Section 1.9 — Evaluation of Noise Levels.

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

a. Provide a description of the "negligible increase" on the noise levels the proposed facility would have on the area, particularly in reference to the Sand Hill community directly south of the proposed site.

Sound is measured in decibels. The units of the noise studies are expressed as dB or dB(A) in relation to the decibels in "A-weighting" scale. "A-weighting" is the most commonly used of a family of curves defined in the International standard IEC 61672:2003 and various national standards relating to the measurement of sound pressure level. This unit is common for measuring environmental noise and industrial noise. It is important to note that multiple sound sources at a given dBA measurement are not additive but rather follow the following relationship (SPL = sound pressure level expressed in dB):

$$SPL_{(total)} = 10\log_{10} \sum_{i=1}^{n} 10^{(SPL_i)/10}$$

Reference: http://www.epd.gov.hk/epd/noise_education/web/ENG_EPD_HTML/m1/intro_5.html

For example 3 sources each at 60 dBA would result in a total sound pressure level of 63 dBA. 3 sources of 60 dBA, 65 dBA, and 70 dBA would result in a total sound pressure level of 71.5 dBA. **Therefore multiple sources yield a net sound pressure level fairly close to the maximum of the sources.**

Additionally, **sound pressure level decreases with distance with a decrease of roughly 6 dBA for doubling of distance and 20 dBA for 10 times the distance per the following:**

$$L_2 = L_1 - |\, 20 \cdot \log\left(\frac{r_1}{r_2}\right) |$$

Reference: http://www.sengpielaudio.com/calculator-distance.htm

For reference the following is a listing of common sounds and there relative sound pressure levels in dBA:

Comparative Examples of Noise Levels

Comparative Examples of Noise Sources, Decibels & Their Effects

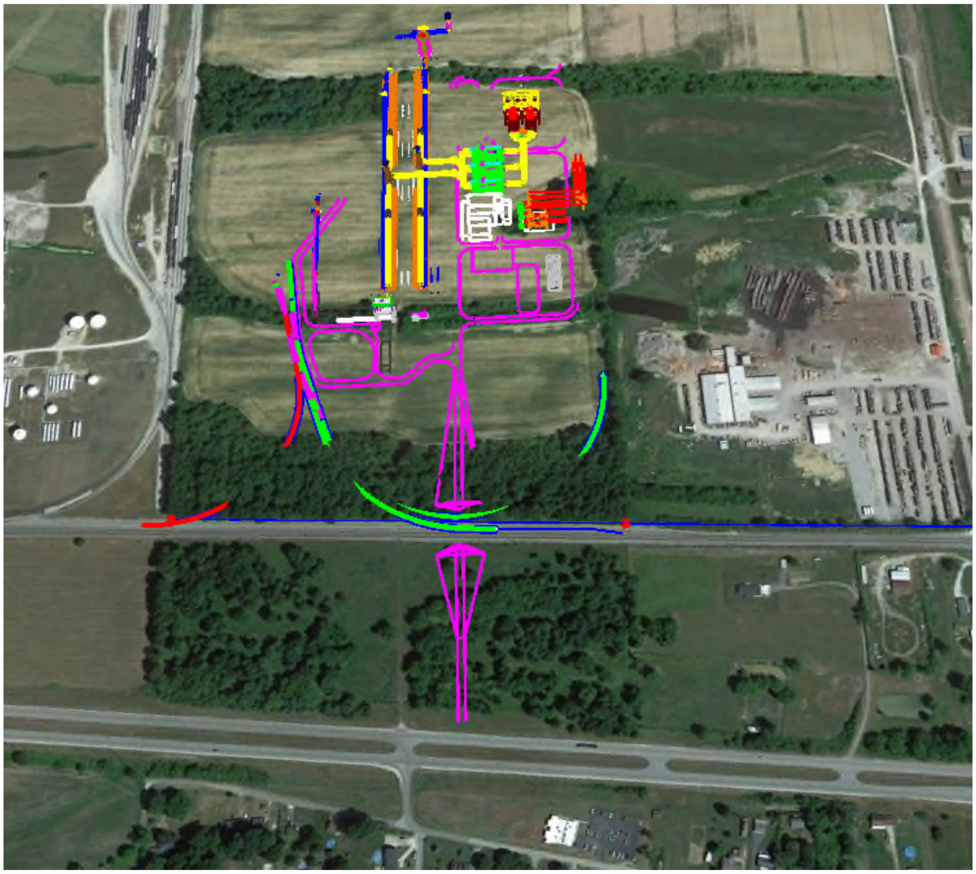
Noise Source	Decibel Level	Decibel Effect
Jet take-off (at 25 meters)	150	Eardrum rupture
Aircraft carrier deck	140	
Military jet aircraft take-off from aircraft carrier with afterburner at 50 ft (130 dB).	130	
Thunderclap, chain saw. Oxygen torch (121 dB).	120	Painful. 32 times as loud as 70 dB.
Steel mill, auto horn at 1 meter. Turbo-fan aircraft at takeoff power at 200 ft (118 dB). Riveting machine (110 dB); live rock music (108 - 114 dB).	110	Average human pain threshold. 16 times as loud as 70 dB.
Jet take-off (at 305 meters), use of outboard motor, power lawn mower, motorcycle, farm tractor, jackhammer, garbage truck. Boeing 707 or DC-8 aircraft at one nautical mile (6080 ft) before landing (106 dB); jet flyover at 1000 feet (103 dB); Bell J-2A helicopter at 100 ft (100 dB).	100	8 times as loud as 70 dB. Serious damage possible in 8 hr exposure
Boeing 737 or DC-9 aircraft at one nautical mile (6080 ft) before landing (97 dB); power mower (96 dB); motorcycle at 25 ft (90 dB). Newspaper press (97 dB).	90	4 times as loud as 70 dB. Likely damage 8 hr exp
Garbage disposal, dishwasher, average factory, freight train (at 15 meters). Car wash at 20 ft (89 dB); propeller plane flyover at 1000 ft (88 dB); diesel truck 40 mph at 50 ft (84 dB); diesel train at 45 mph at 100 ft (83 dB). Food blender (88 dB); milling machine (85 dB); garbage disposal (80 dB).	80	2 times as loud as 70 dB. Possible damage in 8 hr exposure.
Passenger car at 65 mph at 25 ft (77 dB); freeway at 50 ft from pavement edge 10 a.m. (76 dB). Living room music (76 dB); radio or TV-audio, vacuum cleaner (70 dB).	70	Arbitrary base of comparison. Upper 70s are annoyingly loud to some people.
Conversation in restaurant, office, background music, Air conditioning unit at 100 ft	60	Half as loud as 70 dB. Fairly quiet
Quiet suburb, conversation at home. Large electrical transformers at 100 ft	50	One-fourth as loud as 70 dB.
Library, bird calls (44 dB); lowest limit of urban ambient sound	40	One-eighth as loud as 70 dB.
Quiet rural area	30	One-sixteenth as loud as 70 dB. Very Quiet
Whisper, rustling leaves	20	
Breathing	10	Barely audible

[modified from http://www.wenet.net/~hpb/dblevels.html] on 2/2000.
SOURCES: *Temple University Department of Civil/Environmental Engineering (www.temple.edu/departments/CETP/environ10.html), and Federal Agency Review of Selected Airport Noise Analysis Issues, Federal Interagency Committee on Noise (August 1992). Source of the information is attributed to Outdoor Noise and the Metropolitan Environment, M.C. Branch et al., Department of City Planning, City of Los Angeles, 1970.*

Middletown data indicates the highest sound pressure level within the plant (excluding sound level within the steam turbine generator building) during operation was roughly 80 dBA. Typical sound pressure levels in the balance of the plant were on the order of 65 dBA. During the same period sound levels on the adjacent road way <1,500 feet from operations indicated

53 to 67 dBA. The peaks on the roadway of 75 to >80 dBA reflected semi-tractor trailer traffic (matching the indicative table above).

The figure below illustrates the relative locations and anticipated sound levels based on the reference table and the Middletown plant noise data.



The closest residents of the Sand Hill neighborhood are roughly 220 feet from U.S. Highway 23 (per the above reference table freeway noise at a distance of 50 feet is roughly 76 dBA), 1,020 feet from the CSX rail main line (per the above reference table freight trains produce 80 dBA at 15 meters), almost 2,000 feet from the nearest operating unit (Quench tower which based on the Middletown data posted sound levels of roughly 66 dBA), and over 2,800 feet from the highest sound level in the plant (excluding sound levels inside the steam turbine generator building) of 80 dBA representing the area surrounding the air quality control system.

In summary, a negligible increase is expected based on:

1.) The closest (within 220 feet of the closest residence) noise contributor to the Sand Hill residents is U.S. Highway 23 with a reported average of approximately 11,800 vehicles per day at an expected 76 dBA (note from the table above freeway noise at 50 feet is at 76 dBA). The expected sound pressure level at the closest residence from this source calculates to roughly 63 dBA (note that this is generally consistent with the results of the MEA background noise study).

2.) The next closest contributor is the CSX railway (within 1,020 feet of the closest residence) with an expected level of 80 dBA (based on the reference table for a freight train at 15 meters). The expected sound pressure level at the closest residence from this source calculates to roughly 53 dBA.

3.) The closest plant operating unit is the quench tower operation (within 1,950 feet of the closest residence) with an expected level of 66 dBA based on Middletown data. The expected sound pressure level at the closest residence from this source calculates to roughly 28 dBA.

4.) The highest noise contributor in the plant from Middletown data is the air quality control system which also happens to be the furthest unit away (over 2,800 feet from the closest residence) and recorded levels of 75 to 80 dBA. The expected sound pressure level at the house from this source calculates to roughly 39 dBA.

5.) Assuming a worst case peak noise level of 85 dBA at the closest operating unit (1,020 feet from the closest residence) would generate an expected sound pressure level at the closest residence of 53 dBA.

6.) Finally, utilizing contributions from just the Highway and the Rail prior to the plant would generate a sound pressure level of 63.5 dBA at the closest residence (close in relation to the 60 dB background level measured by MEA). Adding contributions from 3, 4, and 5 with the addition of the plant would generate an expected sound pressure level at the closest residence of 63.9 dBA. Literature suggests a 3 dBA shift is required for the human ear to discern a change. Therefore, this change in noise level is not discernible to the human ear and thus we state this as “negligible”.

The summary calculations are shown below for reference:

$$L_2 = L_1 - |20 \cdot \log\left(\frac{r_1}{r_2}\right)|$$

$$SPL_{(total)} = 10\log_{10}\sum_{i=1}^{n}10^{(SPL_i)/10}$$

Freeway Noise at House

Distance 1, r1	50
Sound level 1, L1	76
Distance 2, r2	220
Solve Sound Level 2, L2	**63.1**

Freight Train Noise at House

Distance 1, r1	45
Sound level 1, L1	80
Distance 2, r2	1020
Solve Sound Level 2, L2	**52.9**

Closest Operating Unit at House

Distance 1, r1	25
Sound level 1, L1	66
Distance 2, r2	1950
Solve Sound Level 2, L2	**28.2**

Highest Level from Plant at House

Distance 1, r1	25
Sound level 1, L1	80
Distance 2, r2	2837
Solve Sound Level 2, L2	**38.9**

Closest Peak Plant Noise at House

Distance 1, r1	25
Sound level 1, L1	85
Distance 2, r2	1020
Solve Sound Level 2, L2	**52.8**

Total Sound Pressure Level of All Sources at House

63.9 With Plant
63.5 Without Plant

b. Provide a comparison of the background noises that exist in the vicinity of the proposed site and the anticipated noise from the construction and operation of the proposed facility.

Background level noise contributors include U.S. Highway 23 traffic with the prior mentioned reported average of 11,800 vehicles per day, CSX rail traffic at the front end of the proposed property, industrial noise from existing operations by Mark West and Graf Brothers. The current background levels were measured at 60 dBA at Monitoring Point A and Monitoring Point B, both located directly to the north of the Sand Hill community along State Route 3117, during the South Shore noise study, provided as **Exhibit X.**

Per the Middletown data, there was no impact from construction and operation versus the background noise levels. Additionally, the analysis above indicates an indiscernible increase in noise levels is predicted at the closest residential neighborhood based on plant contributions.

c. Provide comparisons of the anticipated continuous noise created by the operation of the proposed facility to the anticipated peak noise created by the operation of the proposed facility.

The National Institute of Occupational Safety and Health (NIOSH) recommends a maximum noise exposure level of 85 dBA over an 8 hour period otherwise requiring hearing protection. There is only one area of the plant which is at or above this level, and that area is inside the STG building. As indicated by the Middletown data, peak levels in only one area of the plant reached around 80 dBA with the balance of the plant around 55 to 65 dBA. Again, these are inside the plant. As indicated above, with distance to the closest residence the sound level drops. A calculation was added for an 85 dBA noise contribution at the closest operating unit to the residential neighborhood. At this distance the predicted noise level at the house for this source is 53 dBA which is less than the background level.

d. Provide comparisons of anticipated ambient noise created by the construction and operation of the proposed facility during daytime hours to anticipated ambient noise created by the construction and operation of the proposed facility during nighttime hours.

Referencing Middletown data from Exhibit H1, the evening versus daytime construction and operating data shows a minor shift to lower dBA levels for some portions of the plant with the balance at similar levels for evening versus daytime. The above table in response 12 also contains a summary of some of this data. Middletown is typically on production cycles during the daytime hours.

15. Provide a description of any potential odors that might emanate from the proposed facility.

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

The merchant generating facility portion of the heat recovery coke plant is not expected to produce odors as it is a high quality steam converted to power process. Heat recovery cokemaking facilities are inherently different than the traditional vertical byproduct recovery batteries (such as the former New Boston, Ohio coke plant site directly across the Ohio River from South Shore or the former nearby Ashland, AK facility.) The vertical byproduct recovery batteries produce crude tar and light oils containing benzene, toluene, and xylene, all of which have odors. Additionally, the traditional vertical byproduct recovery batteries are positive pressure and any leakage creates emissions. The heat recovery cokemaking process is negative pressure; therefore, any "leakage" would be in-leakage (draws air into the process). Similar to industrial facilities with truck traffic and which utilize heavy equipment, a heat recovery cokemaking facility may have certain odors from time to time, as described below. It is only in certain weather conditions that any odors might emanate from the facility. Predominant wind direction is from the southwest, away from the nearest residential neighborhood toward the Ohio River. Potential odors that may occur at the heat recovery cokemaking facility from time to time are: exhaust smells and gasoline smells from traffic, diesel fuel/kerosene/home heating oil smells from equipment and vehicle usage, a coal-like odor from coal piles or trains, and a slight burnt odor from coke quenching.

16. Refer to Exhibit H — SAR, Section 3.0 — Potential Changes in Adjacent Property Values, page 11. It states, "Because of the appropriate selection of this site and the significant setback distance from US 23, the facility is anticipated to have a marginal but positive effect on community property values." Explain how the selection of the site and setback from U.S. 23 will have a positive effect on property values.

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

Per the positive economic impact of adding wages and taxes directly from plant supervision, operations, and maintenance personnel as well as the indirect wage and tax benefit of supporting business, the plant is anticipated to have a marginal but positive effect on property values. The setback from U.S. Highway 23 is merely indicative of the fact that the closest residential neighborhood is roughly 1,950 feet from the nearest process unit in the plant.

17. Refer to Exhibit H — SAR, Section 5.0 — Road, Rail and Fugitive Dust, Section 5.2 — Road Impacts, page 13, which states, in part, "Construction vehicles and heavy equipment would utilize Johnson's Lane during construction."

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

a. Provide a schedule indicating the time of day and frequency of the projected use of Johnson's Lane by construction vehicles and heavy equipment.

This information will not be available until the plans are finalized, equipment suppliers are selected, and logistics are planned. As indicated above, SunCoke will use commercially reasonable efforts to mitigate traffic issues on Johnson Lane keeping in mind this is a county road (public roadway).

b. Provide a comparison of the number of construction vehicles which will be used to the average daily traffic volume on U.S. Highway 23.

Per response 9.c.2, SunCoke expects an average of 50 trucks per day, with a peak volume on the order of 100 trucks per day, versus the current average of 11,800 vehicles per day on U.S. Highway 23. In other words, SunCoke expects a 0.4% increase in the average daily vehicle traffic.

18. Refer to Exhibit H — SAR, Exhibit H2 — Conceptual View Sheds

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

a. Provide a conceptual view shed of the proposed SunCoke facility from the perspective of the Sand Hill community, which is directly south of the proposed site on the other side of U.S. Highway 23.

See **Exhibit Y** for the additional conceptual view shed from this vantage point.

b. Identify the blue building in the foreground of the picture on the second map.

The structural steel surrounding the heat recovery steam generators (HRSGs) is indicated in blue in the Conceptual View Sheds, seen in Exhibit H2. The colors of the proposed facility displayed in the Conceptual View Sheds are not indicative of the actual colors which will be used and are being used for conceptual purposes only.

19. Refer to the Application, Exhibit J — Proposed South Shore 138 kV Radial Tie Line Feasibility Study, Section 5.1 - Identified Routes and Evaluation, page 9.

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

a. This page states that Route 1 (which is the route ultimately chosen) is 1.2 miles and that 0.9 miles of the route is located in Kentucky. In the Application at Section 2.1 — Proposed Electric Generating Facility — General Information, page 3, it states that 0.7 miles of the radial tie line would be located in Kentucky. Explain the discrepancy and state which is accurate.

Approximately 0.7 miles of the proposed radial tie line will be located in Kentucky. The 0.9 miles of the radial tie line was based on a conceptual study of broad route alternatives. Due to the optimization of the selected route through strategic placement of radial tie line structures, the length of the radial tie line eventually decreased.

b. Exhibit J Section 5.0, page 9, also states that "Route 1 has the greatest number of previously recorded archaeological sites within 100 and 1,000 feet (4 and 14 respectively). Impacts to archaeological sites can often be avoided or minimized by the location of the transmission line structures during the detailed design process.' State whether the impacts to the 18 archaeological sites have been minimized. If so, explain how the impacts were minimized.

Impacts to the recorded archaeological sites have been minimized by strategically locating the vast majority of radial tie line structures outside of these recorded archaeological boundaries. See response to Request #21 for additional details.

20. Refer to the Application Exhibit J — Proposed South Shore 138 kV Radial Tie Line Feasibility Study, Section 5.2 — Route Ranking and Results, Table 2 on page 14.

Under the Land Use heading, Route 1 is shown as crossing one property in Kentucky. Confirm that the property crossed is that which is owned by SunCoke. If this cannot be confirmed, identify the property to be crossed.

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

All property in Kentucky that the proposed radial tie line would cross would be owned by SunCoke. SunCoke does not yet own the property but it has option agreements in place with the applicable landowners.

21. Refer to the Application, Exhibit J — Proposed South Shore 138 kV Radial Tie Line Feasibility Study, Section 6.0 — Conclusion, page 15. The first paragraph states, "[w]hile cultural resource issues may create potential delays and additional costs, they do not appear to represent fatal flaws, based on the data gathered to date." Identify the "cultural resources issues" to which this statement refers.

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

The site has been subject to significant cultural resource investigation, and the location of sensitive features (and associated impact minimization strategy) has been considered throughout the design process. Due to the nature of the project, impacts to some of the cultural resources on the site are unavoidable. Sites 15Gp183 and 15Gp219, both determined eligible for the NRHP, are large prehistoric deposits extending from one side of the South Shore Facility site to the other. In regard to 15Gp183, located on a natural levee adjacent to the Ohio River, the project has been designed to minimize impact and restrict all components on this landform to two disturbance corridors that intersect site boundaries. One of these corridors is 80 feet in width, and is to contain the conveyor system and the access road. The other is to be 30 feet wide and will accommodate the water intake pump house and water intake and discharge lines. In this way, impacts to 15Gp183 are limited to 5,852.9 square meters (63,000 square feet) of the total site area of 67,286 square meters (724,260 square feet). With respect to the proposed radial tie line, all structures with the exception of a single structure (Str. No. 5) located near the Ohio River have been strategically located to avoid cultural resource impacts. Due to Ohio River span considerations driven by the Ohio side structure locations, Str. No. 5 may need to be located adjacent to the 30-foot wide corridor and may result in minor localized impacts to 15Gp183.

In regard to 15Gp219, this large prehistoric site is situated at the edge of the second terrace. No avoidance of this resource by the project was possible, and the entire 77,121 square meters (830,123 square foot) of the site lying within project boundaries has been recommended for mitigation.

The United States Army Corps of Engineers, in consultation with the Kentucky Heritage Council, is currently reviewing a Data Recovery Plan for Archaeological Sites 15Gp183 and 15Gp219, submitted by SunCoke and the plan would be implemented prior to and during the construction phase.

22. Refer to SunCoke's Motion for Deviation from Setback Requirements, page 6, which states that "SunCoke would also install a green belt' surrounding the exterior view of the plant." Provide details of the green belt to be installed.

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

Representative details of a green belt would be made available in a landscape plan which would be finalized upon advancement of the plant design. SunCoke would maintain the existing tree line where possible.

An indicative schematic shows where trees would need to be cleared at the south end of the facility to accommodate the construction parking lot, bridge construction, utility routing, railroad, etc. We anticipate working to maintain a tree line around the border of these areas.

23. Refer to SunCoke's Motion for Deviation from Setback Requirements, page 7, which states that "SunCoke is currently working with the Kentucky Department of Transportation on a bridge overpass from U.S. 23 over the CSX railroad into the plant."

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

a. Submit any written documents, agreements, plans, minutes from meetings, and correspondences with the Kentucky Department of Transportation concerning construction of the bridge overpass.

Additional information on communications surrounding the bridge overpass design is provided as **Exhibit Z.**

b. What is the timeline for construction of the bridge overpass? Would it be completed in time for operation of the plant?

Schedule details are not known, the goal is to complete the bridge overpass in conjunction with the plant startup.

c. How will the construction of the bridge overpass be funded?

Funding for the overpass has not been identified and will not be identified until such time as there is a commitment from SunCoke to build and operate the facility as proposed to the Kentucky Economic Development Cabinet.

d. How will the necessary changes to the electric lines paralleling the railroad in the vicinity of the proposed bridge overpass and footbridge be funded? Submit any documents or minutes from meetings with the electric company.

Funding for the utility relocation has not been identified and will not be identified until such time as there is a commitment from SunCoke to build and operate the facility as proposed to the Kentucky Economic Development Cabinet.

There are multiple routing options for the KY 69 kV power supply to the plant. As this has not yet been finalized, the rerouting of existing power lines has been verbally discussed but nothing is yet definitive. Lines are anticipated to be raised to accommodate the bridge overpass.

Notes from the January 22nd, 2014 meeting with KY power are provided as **Exhibit AA.**

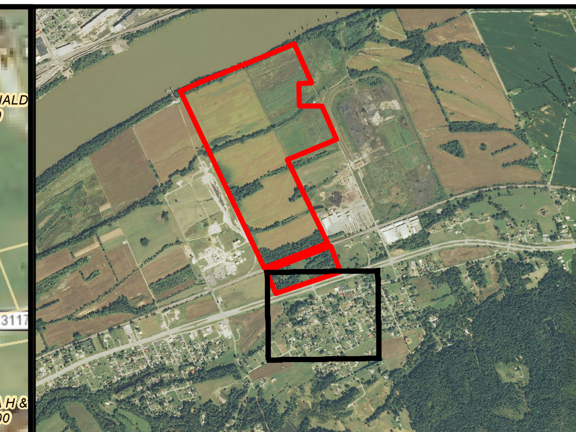
24. Refer to the Application, Exhibit H2 — Conceptual View Sheds. When was the residence on the Gibson property built? When did Graf Brothers begin operations on the DGGG Realty site?

WITNESS RESPONSIBLE FOR RESPONDING TO QUESTIONS RELATED TO THE INFORMATION PROVIDED:

DAVID SCHWAKE

According to the Greenup County PVA, construction of the Gibson residence began sometime in 2009 and was likely finished sometime in 2010, considering 2011 was the first year of full taxes being paid. The Graf Brothers began operations sometime before 2005, according to the Greenup County PVA.

61272451.1



N

Legend

Approximate Project Boundary

Greenup County Parcel

0 100 200 400

Scale In Feet

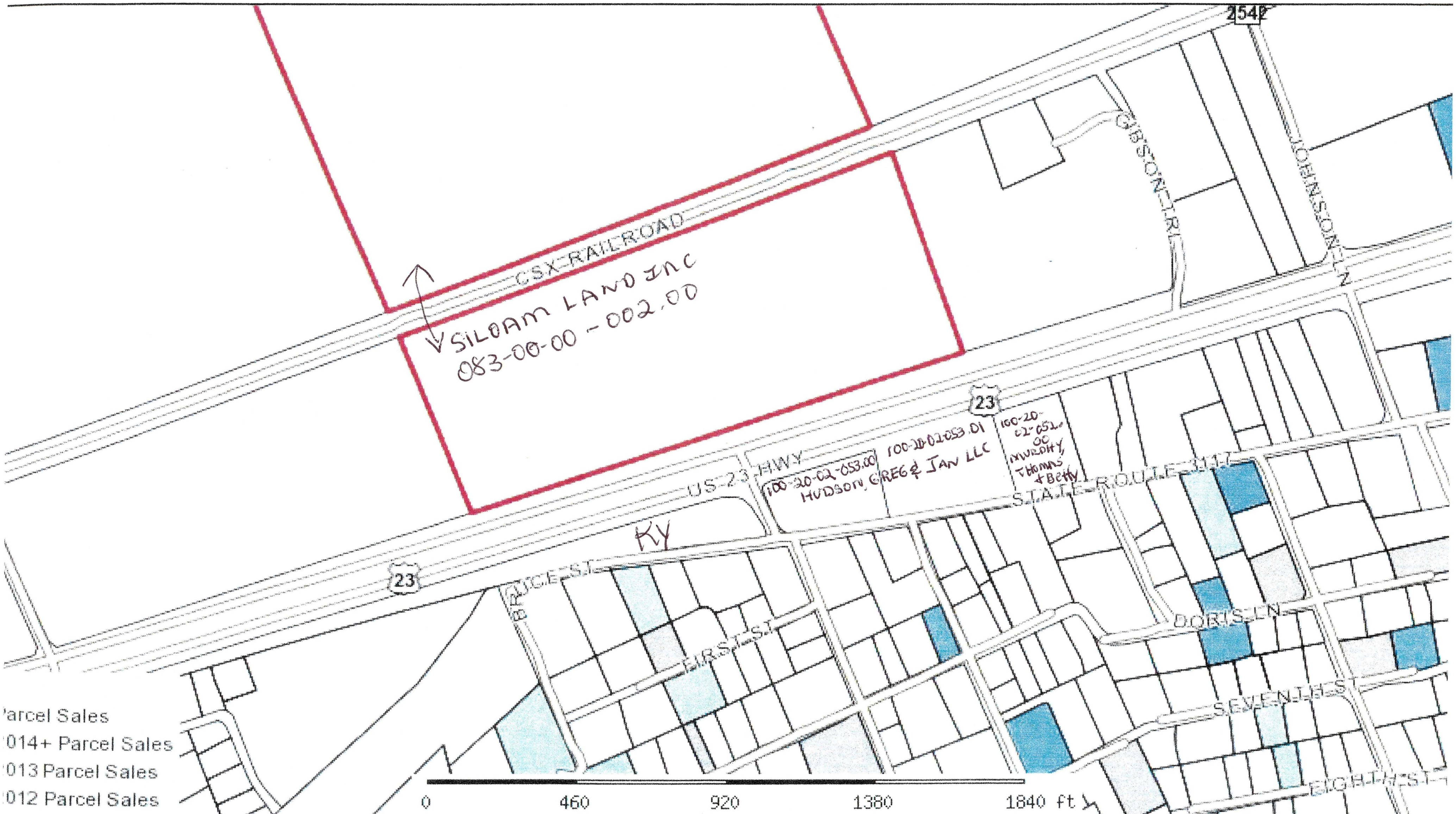
BASE MAP SOURCE:
National Agricultural Imagery Program, 2013

SunCoke Energy
South Shore Facility

FIGURE 8
GREENUP COUNTY PARCELS SOUTH OF PROPOSED SESS FACILITY

DATE: 12/4/2014	
CREATED BY: KB	CHECKED BY: JP
JOB NO. 25368724	URS

J:\Project\S\Suncoke\25368724 Project Raven\Data-Tech\GIS\Siting\Figure 8_SouthShoreSiting_Residentail parcels to south of US23.mxd



Property Owners Across US 23

083-00-00-002.00 Acres: 0

SILOAM LAND INC	Land FCV	616400
US 23 N 0	Imp FCV	0

March 4, 2014

Mr. Richard A. Hemann
Regulatory Project Manager
Energy Resource Branch
USACE, Huntington District, CELRH-RD-E
502 8th Street
Huntington, WV, 25701

Re: Response to United States Fish and Wildlife Service Comments
Public Notice No. LRH-2009-00264-OHR
Proposed SunCoke Energy South Shore, LLC Facility
Greenup County, Kentucky

Dear Mr. Hemann,

On behalf of SunCoke Energy South Shore, LLC (SESS), this letter has been prepared to address comments provided by United States Fish and Wildlife Service (USFWS) in the attached correspondence dated May 16, 2013. The attached comments were submitted in response to Public Notice No. LRH-2009-00264-OHR associated with the Army Corps of Engineers (USACE) Section 10/404 Permit application for construction of a heat-recovery coke plant to be located near the city of South Shore in Greenup County, Kentucky. URS understands that the USACE received comments from parties who might be affected by the construction of the proposed facility, and has requested that responses be prepared to address each set of comments.

The attached letter indicates that the USFWS has reviewed the Public Notice and offered the following comments in accordance with the Endangered Species Act (ESA) of 1973 (87 Stat. 884, as amended; 16 U.S.C. 1531 et seq.).

Federally Listed Mussels

A mussel survey was previously conducted in response to the USFWS's concerns regarding the potential for the proposed project-associated barge loading and fleeting facility to adversely affect federally listed mussels. The attached July 19, 2012 letter concurs with the conclusions of the September 2008 mussel survey in which it was determined that the proposed project would not likely adversely affect federally listed mussels.

Gray Bat (Myotis grisescens)

The Public Notice states that no suitable gray bat habitat is present within the proposed project area, and that SESS will utilize best management practices during the construction of the facility. Based on this information, the USFWS concurs that the proposed project would not likely adversely affect the gray bat.

Indiana Bat (Myotis sodalis)

The Public Notice indicates that approximately 45 acres of potential Indiana bat summer roost habitat (i.e., forested area) would be removed as a result of the proposed project, and that SESS may be able to conduct all removal of trees between the dates of October 15, 2014 to March 31, 2015. This approach would avoid direct effects to Indiana bats that may be utilizing habitat within the project area during the

URS Corporation
525 Vine Street, Suite 1800
Cincinnati, Ohio 45202
Tel: 513.651.3440
Fax: 877.660.7727

timeframe when the species is anticipated to be present. If SESS could not commit to this seasonal tree clearing restriction, the project area may be surveyed to determine if Indiana bats are present or absent.

SESS will conduct all removal of trees between the dates of October 15, 2014 to March 31, 2015 in order to avoid direct effects to Indiana bats that may be utilizing habitat within the project area during the timeframe when the species is anticipated to be present.

If you have any questions or require additional information, please feel free to contact the undersigned or Dave Schwake of SESS at (215) 384-5920.

Sincerely,

URS

Kevin R. Bailey
Project Manger

John D. Priebe, P.E.
Principal

Attachments: United States Fish and Wildlife Service Letter dated May 16, 2013
United States Fish and Wildlife Service Letter dated July 19, 2012

Porter, Susan A

From:	Gruhala, James [james_gruhala@fws.gov]
Sent:	Thursday, May 16, 2013 3:28 PM
To:	Porter, Susan A
Subject:	Re: CELRH-RD-E Public Notice: LRH-2009-00264-OHR
Attachments:	2012-B-0707.PDF

Ms. Susan Porter
United States Army Corps of Engineers
502 8th Street
Huntington, West Virginia 25701-2070

Re: FWS 2012-B-0707; CELRH-RD-E Public Notice: LRH-2009-00264-OHR, SunCoke Energy South Shore, LLC, South Shore Facility Project, located in Greenup County, Kentucky

Dear Ms. Porter:

Please accept this correspondence and maintain for your records as the U.S. Fish and Wildlife Service's (Service) official response to the above-referenced Public Notice. The Service has reviewed the Public Notice and offers the following comments in accordance with the Endangered Species Act (ESA) of 1973 (87 Stat. 884, as amended; 16 U.S.C. 1531 et seq.).

Federally Listed Mussels
As stated in the Public Notice, a mussel survey was conducted in response to the Service's concerns regarding the potential for the proposed project-associated barge loading and fleeting facility to adversely affect federally listed mussels. The Service has previously reviewed the survey and concurred that the proposed project would likely adversely affect federally listed mussels. Our July 19, 2012 concurrence letter (attached) is based on the results of the mussel survey that was completed in September, 2008. Therefore, the Service concurs that the proposed project would not likely adversely affect federally listed mussels.

Gray bat (Myotis grisescens)
The Public Notice states that no suitable gray bat habitat is present within the proposed project area, and that the applicant will utilize best management practices during the construction of the facility. Based on this information, the Service concurs that the proposed project would not likely adversely affect the gray bat.

Indiana bat (Myotis sodalis)
The Public Notice indicates that approximately 45 acres of potential Indiana bat summer roost habitat (i.e., forested area) would be removed as a result of the proposed project, and that the applicant may be able to conduct all removal of trees between the dates of October 15 to March 31. This approach would avoid direct effects to Indiana bats that may be utilizing habitat within the project area during the timeframe when the species is anticipated to be present. If the project proponent cannot commit to this seasonal tree clearing restriction, the project area may be surveyed to determine if Indiana bats are present or absent.

The Service agrees with the planned approach to address the project's potential to adversely affect the Indiana bat. The Service also wants to inform the applicant of another available option that could be considered in lieu of seasonal clearing or surveying. The applicant could request entering into a Conservation Memorandum of Agreement (MOA) with the Service. By entering into a Conservation MOA with the Service, Cooperators gain flexibility in project timing with regard to the removal of suitable Indiana bat habitat. In exchange for this flexibility, the Cooperator provides recovery-focused conservation benefits to the Indiana bat through the implementation of minimization and mitigation measures as set forth in the Indiana Bat Mitigation Guidance for the Commonwealth of Kentucky. For additional information about this option, please notify our office.

Please inform us how the applicant wants to address the project's potential to adversely affect the Indiana bat. This is necessary before the Service can complete ESA section 7 consultation for the project and ensure that the proposed project would be in full compliance with the ESA.

Please contact me if you have any questions regarding our response. Refer to project number FWS-2012-B-0707.

Sincerely,

Jim Gruhala

James Gruhala
Fish & Wildlife Biologist
U.S. Fish & Wildlife Service
KY Ecological Services Field Office
330 West Broadway, Room 265
Frankfort, KY 40601

(502)695-0468 ext. 116

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Kentucky Ecological Services Field Office
330 West Broadway, Suite 265
Frankfort, Kentucky 40601
(502) 695-0468

July 19, 2012

Mr. Benjamin Otto
Ecologist
URS Corporation
525 Vine Street, Suite 1800
Cincinnati, Ohio 45202

Re: FWS 2012-B-0707; URS Corporation, SunCoke Energy South Shore, LLC, South Shore Facility Project, located in Greenup County, Kentucky

Dear Mr. Otto:

The U.S. Fish and Wildlife Service (Service) has reviewed your correspondence of July 11, 2012 including the *Mussel Survey at Ohio River Mile 351.1 – 351.6 Along the Left Descending Bank* (Report), of November, 2008 for the above-referenced project. The Report was prepared by Mainstream Commercial Drivers, Inc. for the Malcolm Pirnie, Inc.. The Service offers the following comments in accordance with the Endangered Species Act (ESA) of 1973 (87 Stat. 884, as amended; 16 U.S.C. 1531 *et seq.*).

The mussel survey was conducted in response to the Service's concerns regarding the potential for the proposed project-associated barge loading and fleeting facility to adversely affect the following federally listed mussels.

Common Name	Scientific Name	Federal Status
clubshell	*Pleurobema clava*	endangered
fanshell	*Cyprogenia stegaria*	endangered
orangefoot pimpleback	*Plethobasus cooperianus*	endangered
pink mucket	*Lampsilis abrupta*	endangered
ring pink	*Obovaria retusa*	endangered
rough pigtoe	*Pleurobema plenum*	endangered
sheepnose	*Plethobasus cyphyus*	endangered

The survey methods were approved by the Service and the Service believes that the survey effort covered the area of the Ohio River that would likely be significantly impacted by the proposed barge facility. According to the Report, the action area was surveyed on September 25, 2008. Divers had good visibility conditions. The survey methods consisted of a total of 8 transects plus a 15-minute qualitative search located in the area with the highest density of mussels. During the survey a total of 29 individual mussels were discovered representing 6 species. No federally listed mussels were found.

Based on the overall estimated mussel density and because no federally listed mussels were found, the Service concurs that the proposed project would not likely adversely affect the clubshell, fanshell, orangefoot pimpleback, pink mucket, ring pink, rough pigtoe, and sheepnose mussels.

Indiana bat

The federally endangered Indiana bat (*Myotis sodalis*) has the potential to occur within the proposed project area. Indiana bats may utilize trees in the vicinity of the project area as summer roost habitat. The habitat assessment indicates that the proposed project would result in the removal of approximately 45 acres of potential Indiana bat habitat (*i.e.*; forested area).

Your correspondence indicates that the project proponent may be able to conduct all removal of trees between the dates of October 15 to March 31. This approach would avoid direct effects to Indiana bats that may be utilizing habitat within the project area during the timeframe when the species is anticipated to be present. If the project proponent cannot commit to this seasonal tree clearing restriction, the project area may be surveyed to determine if Indiana bats are present or absent.

The Service agrees with the planned approach to address the project's potential to adversely affect the Indiana bat. The Service also wants to inform you of another option that that project proponent may want to consider entering into a Conservation Memorandum of Agreement (MOA) with the Service in lieu of seasonal clearing or surveying.

If your project schedule requires the clearing of potential Indiana bat habitat (*i.e.*, trees that are greater than 5 inches DBH and exhibit any of the following characteristics: exfoliating bark, cracks, crevices, dead portions, cavities, broken limbs) during the period of April 1 to October 14, you have two primary options for addressing impacts to Indiana bats. First, you can survey the project site, or you can enter into a Conservation MOA with the Service. By entering into a Conservation MOA with the Service, Cooperators gain flexibility in project timing with regard to the removal of suitable Indiana bat habitat. In exchange for this flexibility, the Cooperator provides recovery-focused conservation benefits to the Indiana bat through the implementation of minimization and mitigation measures as set forth in the Indiana Bat Mitigation Guidance for the Commonwealth of Kentucky. For additional information about this option, please notify our office.

Please inform us how the project proponent wants to address the project's potential to adversely affect the Indiana bat.

gray bat

The federally endangered gray bat (*Myotis grisescens*) has been documented to occur within the vicinity of the proposed project area. Gray bats roost, breed, rear young, and hibernate in caves year round. They migrate between summer and winter caves and will use transient or stopover caves along the way. Gray bats eat a variety of flying aquatic and terrestrial insects present along streams, rivers, and lakes. Low-flow streams produce an abundance of insects, and are especially valuable to the gray bat as foraging habitat. For hibernation, the roost site must have an average temperature of 42 to 52 degrees F. Most of the caves used by gray bats for hibernation have deep vertical passages with large rooms that function as cold air traps. Summer caves must be warm, between 57 and 77 degrees F, or have small rooms or domes that can trap the body heat of roosting bats. Summer caves are normally located close to rivers or lakes where the bats feed. Gray bats have been known to fly as far as 12 miles from their colony to feed. Additional, habitat and life history information on these species is available on the Service's national website at www.fws.gov.

Because we have concerns relating to the gray bat on this project and due to the lack of occurrence information available on this species relative to the proposed project area, we have the following recommendations relative to gray bats.

1. Based on the presence of numerous caves, rock shelters, and underground mines in Kentucky, we believe that it is reasonable to assume that other caves, rock shelters, and/or abandoned underground mines may occur within the project area, and, if they occur, they could provide winter/summer habitat for gray bats. Therefore, we would recommend that the project proponent survey the project area for caves, rock shelters, and underground mines, identify any such habitats that may exist on-site, and avoid impacts to those sites pending an analysis of their suitability as gray bat habitat by this office.

2. Sediment Best Management Practices (BMPs) should be utilized and maintained to minimize siltation of the streams located within and in the vicinity of the project area, as these streams represent potential foraging habitat for the gray bat. A plan for BMP implementation should be submitted to our office for approval.

Thank you again for your request. Your concern for the protection of endangered and threatened species is greatly appreciated. If you have any questions regarding the information that we have provided, please contact James Gruhala at (502) 695-0468 extension 116.

Sincerely,

Virgil Lee Andrews, Jr.

Virgil Lee Andrews, Jr.
Field Supervisor

URS

March 4, 2014

Mr. Richard A. Hemann
Regulatory Project Manager
Energy Resource Branch
USACE, Huntington District, CELRH-RD-E
502 8th Street
Huntington, WV, 25701

Re: Response to Columbia Gas Transmission Comments
Public Notice No. LRH-2009-00264-OHR
Proposed SunCoke Energy South Shore, LLC Facility
Greenup County, Kentucky

Dear Mr. Hemann,

On behalf of SunCoke Energy South Shore, LLC (SESS), this letter has been prepared to address comments provided by Columbia Gas Transmission, LLC (Columbia Gas) in the attached correspondence dated May 21, 2013. The attached comments were submitted in response to Public Notice No. LRH-2009-00264-OHR associated with the Army Corps of Engineers (USACE) Section 10/404 Permit application for construction of a heat-recovery coke plant to be located near the city of South Shore in Greenup County, Kentucky. URS understands that the USACE received comments from parties who might be affected by the construction of the proposed facility, and has requested that responses be prepared to address each set of comments.

The attached letter indicates that Columbia Gas operates pipeline facilities in the vicinity of the proposed project, and that certain Columbia Gas requirements pertain to construction in the vicinity of such facilities (i.e., field survey, plan review, etc.). It should be noted that the Columbia Gas pipeline is not located within the proposed project boundary, but is located on the MarkWest property to the west (see attached Figure 1). Nevertheless, given the proximity of the proposed facility with reference to the nearby Columbia Gas pipeline, SESS will coordinate site activities and construction plan reviews, as appropriate, with Mr. Craig Roberts as requested in the attached letter.

If you have any questions or require additional information, please feel free to contact the undersigned or Dave Schwake of SESS at (215) 384-5920.

Sincerely,

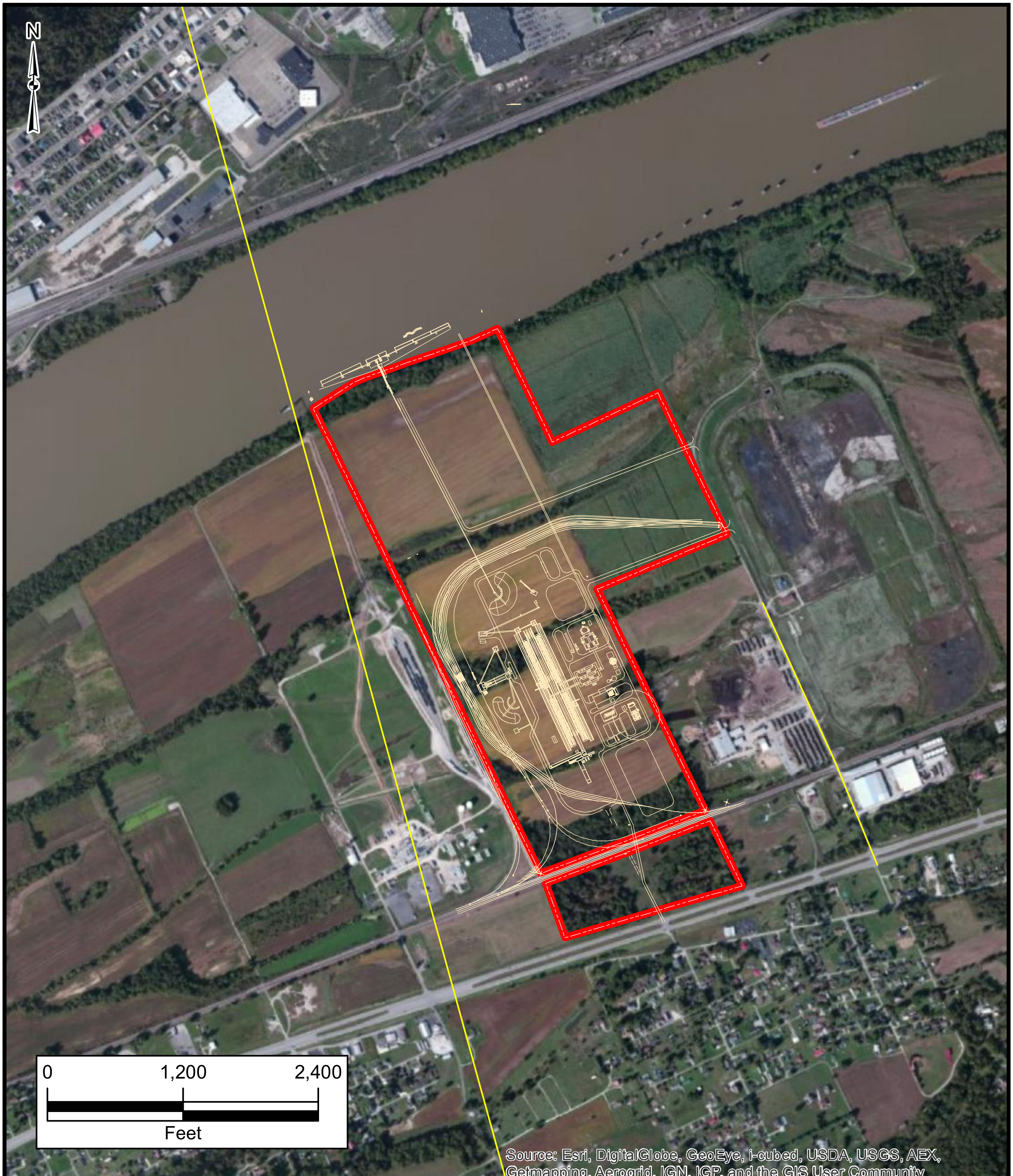
URS

Kevin R. Bailey
Project Manager

John D. Priebe, P.E.
Principal

Attachments: Figure 1
Columbia Gas Transmission Letter dated May 21, 2013

Path: J:\Project\S\Suncoke\25368724 Project Raven\Data-Tech\GIS\404_ColumbiaGas_PNcomment.mxd

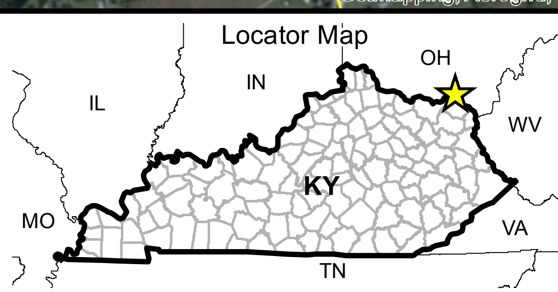


Legend

Proposed Site Features

Columbia Gas Natural Gas Line

Proposed Project Boundary



SunCoke Energy South Shore Facility

FIGURE 1
LOCATION OF UNDERGROUND NATURAL GAS LINE

APPLICATION TO THE ARMY CORPS OF ENGINEERS FOR A SECTION 10/404 PERMIT

JOB NO. 25368724

URS

Portis

Columbia Gas
Transmission.
A NiSource Company
1700 MacCorkle Ave., SE
P. O. Box 1273
Charleston, WV 25325-1273

May 21, 2013

Mr. David Schwake
SunCoke Energy
1011 Warrenville Road, Suite 600
Lisle, IL 60532

Subject: **Public Notice No. LRH-2009-00264-OHR**

Affected Pipelines: **Line UKY**

Dear Mr. Schwake,

In response to a notice regarding your application with the Army Corps of Engineers, Huntington District, Columbia Gas Transmission, LLC **does** have facilities in the vicinity of the proposed construction area.

In order to assure the exact location of Columbia's facilities in relation to this project, it will be necessary for you to perform a field survey. Please contact Team Leader Craig Roberts at 304-453-7502 to schedule a locate of pipeline facilities. **It is imperative that the location and depth of Columbia's facilities be accurately depicted on the design drawings.**

Columbia engineering personnel will be required to review your project plans. Review of the design plans, evaluation of construction activity on pipeline operating stress level, and subsequent onsite inspection as required to provide appropriate construction over-sight, will be considered reimbursable to Columbia. Prepayment of a fee will be required based on the scope of construction activity anticipated near Columbia's facilities. A pipeline appears to be located near the area involved in this project. The fee will be set based on the final scope shown on detailed plans. The sponsor of the project should be advised of this requirement. **No construction work will be permitted near Columbia's facilities until this matter is addressed.**

Enclosed for your use and reference is a copy of Columbia's "Minimum Guidelines for Construction Near Natural Gas Pipeline Facilities". Please be aware that these guidelines represent the minimum conditions required to conduct construction activities in close proximity to, or directly affecting, Columbia facilities. More restrictive measures may be necessary based on particular parameters associated with each individual project and site-specific conditions related to that project.

This letter shall not be considered as authorization to proceed with the contemplated project. Consent to proceed with construction in the vicinity of Columbia facilities will only be provided at a future date when these and any future stipulations deemed necessary have been met and you have received written consent of your plans from Columbia.

Sincerely,

Jeannie L. Bess

Jeannie L. Bess
Land Analyst II, Asset Management

Note: Involvement status relates solely to facilities owned and/or operated by Columbia Gas Transmission Corporation

Enclosure

CC: Army Corps of Engineers, Huntington District
Craig Roberts – Team Leader
Bruce Reynolds – Land Agent

March 4, 2014

Mr. Richard A. Hemann
Regulatory Project Manager
Energy Resource Branch
USACE, Huntington District, CELRH-RD-E
502 8th Street
Huntington, WV, 25701

Re: Response to Kentucky Department for Environmental Protection Comments
Public Notice No. LRH-2009-00264-OHR
Proposed SunCoke Energy South Shore, LLC Facility
Greenup County, Kentucky

Dear Mr. Hemann,

On behalf of SunCoke Energy South Shore, LLC (SESS), this letter has been prepared to address comments provided by the Kentucky Department for Environmental Protection (KDEP) in the attached correspondence dated June 6, 2013. The attached comments were submitted in response to Public Notice No. LRH-2009-00264-OHR associated with the Army Corps of Engineers (USACE) Section 10/404 Permit application for construction of a heat-recovery coke plant to be located near the city of South Shore in Greenup County, Kentucky. URS understands that the USACE received comments from parties who might be affected by the construction of the proposed facility, and has requested that responses be prepared to address each set of comments.

The attached letter indicates that various state agencies within KDEP provided comments concerning the proposed SESS project. Those comments and associated responses are summarized below:

- The Kentucky Division for Air Quality (KDAQ) indicated that certain Kentucky Administrative Regulations (KAR) may apply to this project, such as taking reasonable precautions to prevent particulate matter from becoming airborne, the prohibition of open burning, etc. The letter also offered compliance suggestions with respect to National Ambient Air Quality Standards (NAAQS) compliance. SESS applied for a Title V air permit authorizing construction and operation of the facility as a new major source on December 10, 2012. The KDAQ issued a Public Notice of the proposed project on December 27, 2013, and this notice was made available for 30 days. The Title V air permit and other related environmental plans to be developed for the facility will address these items, as appropriate.

- The Kentucky Division of Water (KDOW) indicated that an individual Clean Water Act (CWA) Section 401 Water Quality Certification (WQC), a Permit to Construct Across or Along a Stream (SCP), a Water Withdrawal Permit (WW Permit), and a Groundwater Protection Plan (GWPP) would be required for this project. The project team is aware of these requirements and a summary of relevant items is provided below:

    - KDOW issued the SCP to SESS on November 20, 2013.

    - KDOW issued the Section 401 WQC to SESS on January 24, 2014.

    - A WW Permit Application has been prepared and will be submitted to the KDOW in the spring of 2014.

URS Corporation
525 Vine Street, Suite 1800
Cincinnati, Ohio 45202
Tel: 513.651.3440
Fax: 877.660.7727

  - A GWPP will be necessary for operational activities at the SESS facility, and the plan will be prepared prior to plant operation. A GWPP will not be necessary for construction activities in accordance with Section 2, 401 KAR 5:037, Scope and Applicability of GWPPs. No applicable activities identified in Section 2 will occur during construction, such as storing hazardous waste. Best Management Practices [BMPs] (such as storing construction waste in dumpsters) will be utilized during construction activities, and will be addressed in the construction Stormwater Pollution Prevention Plan (SWPPP).

- The Kentucky State Nature Preserves Commission (KSNPC) noted the presence of recorded locations of Northern leopard frog (Rana pipiens, KSNPC special concern) and Sedge Wren (Cistothorus platensis, KSNPC special concern) on the South Shore Wildlife Management Area, which is just to the west of the proposed site. The KSNPC indicated that possible habitat on the property that will be disturbed should be surveyed for the presence of these species.

  SESS has coordinated with the United States Fish and Wildlife Service (USFWS) and the Kentucky Department of Fish and Wildlife Resources (KDFWR) regarding potential impacts to threatened and endangered species as a result of the proposed construction of the SESS Facility. The sedge wren (Cistothorus platensis) and northern leopard frog (Rana pipiens) were not identified by either agency as a threatened or endangered species in the Commonwealth of Kentucky (see attached July 19, 2012 and May 16, 2013 letters).

  In the attached October 2008 letter from the KSNPC, the habitat of the northern leopard frog was identified as consisting of springs, slow streams, marshes, bogs, ponds, canals, floodplains, reservoirs, and lakes; usually permanent water with rooted aquatic vegetation. The sedge wren is a migratory species within Kentucky and this species' habitat consists of grassy and sedgy marshes and meadows. These birds forage low in vegetation, sometimes flying up to catch insects in flight.

  Based on URS' ecological surveys for this Project, land use on the proposed SESS Facility property is primarily agricultural land with small wetland habitats and a riparian corridor. The wetland habitats identified onsite are generally small, linear forested woodlots and/or fencerows between agricultural fields. The most suitable habitat for the sedge wren and northern leopard frog located within the project boundary appears to be Wetland 13. Wetland 13 is an approximately 4.1-acre palustrine emergent wetland (PEM) dominated by sedges and grasses, located within the Ohio River floodplain, and is seasonally inundated.

  Wetland habitat and stream riparian area impacts have been avoided to the maximum extent practical for both facility placement and access roads. Engineering design for the Project has avoided any impact to Wetland 13. During URS' 2012 ecological field survey, additional potential habitats for the sedge wren and northern leopard frog were also observed on the adjacent northeast and east properties.

  Based on the current construction plans, the most suitable wetland habitat (Wetland 13) for the sedge wren and northern leopard frog on the proposed SESS property will not be disturbed and can be utilized by these species if they are present in the project area. Although wetland habitat will be impacted by the construction footprint of the Project, URS and SESS believes there is sufficient habitat within Wetland 13 and beyond the proposed work limits on adjacent property that the sedge wren and/or northern leopard frog can utilize. Based on the avoidance of potential habitat on the proposed SESS property, presence of suitable habitat on adjacent property, and mobility of these species, the proposed activity should not significantly impact the sedge wren and northern leopard frog species.

Furthermore, URS' discussions with the KDFWR indicated that the Special Concern designation of the sedge wren and northern leopard frog indicates that not enough information is known about the overall population of these species to designate them as threatened or endangered in Kentucky. To date, the Commonwealth of Kentucky has not passed any laws or requirements that would require further study of impacts to potential habitats of these species.

If you have any questions or require additional information, please feel free to contact the undersigned or Dave Schwake of SESS at (215) 384-5920.

Sincerely,

URS

Kevin R. Bailey
Project Manger

John D. Priebe, P.E.
Principal Engineer

Attachments: Kentucky Department for Environmental Protection Letter dated June 6, 2013
Kentucky State Nature Preserves Commission Letter dated October 9, 2008
United States Fish and Wildlife Service Letter dated July 19, 2012
United States Fish and Wildlife Service Letter dated May 16, 2013

Porter

ENERGY AND ENVIRONMENT CABINET

Steven L. Beshear
Governor

Leonard K. Peters
Secretary

R. Bruce Scott
Commissioner

DEPARTMENT FOR ENVIRONMENTAL PROTECTION
300 FAIR OAKS LANE
FRANKFORT, KENTUCKY 40601
PHONE (502) 564-2150
FAX (502) 564-4245
www.dep.ky.gov

June 6, 2013

U.S. Army Corps of Engineers
Huntington District
Attn: CELRH-RD-E, LRH-2009-00264-OHR
502 8th Street
Huntington, West Virginia 25701-2070

RE: Coordinated State Response

Public Notice No:	LRH-2009-00264-OHR
Applicant:	Mr. David Schwake/SunCoke Energy
Proposed Activity:	To discharge fill materials into waters of the United States in association with the construction of an industrial development referred to as SunCoke Energy South Shore Facility located in Greenup County, Kentucky.

To Whom It May Concern:

The Energy and Environment Cabinet's Department for Environmental Protection has coordinated the above referenced public notice with concerned state agencies in order to prepare a statement of the Commonwealth's concerns on the proposed activity. We have the following comments concerning this project.

1. The Kentucky Division for Air Quality provided the following comments concerning Kentucky Administrative Regulations that may apply to this project. Questions should be directed to Joe Forgacs, at (502) 564-3999. The Division also suggests an investigation into compliance with applicable local government regulations.

Kentucky Division for Air Quality Regulation 401 KAR 63:010 Fugitive Emissions states that no person shall cause, suffer, or allow any material to be handled, processed, transported, or stored without taking reasonable precaution to prevent particulate matter from becoming airborne. Additional requirements include the covering of open bodied trucks, operating outside the work area transporting materials likely to become airborne, and that no one shall allow earth or other material being transported by truck or earth moving equipment to be deposited onto a paved street or roadway. Please note the Fugitive Emissions Fact Sheet located at http://air.ky.gov/Pages/OpenBurning.aspx.

Kentucky Division for Air Quality Regulation 401 KAR 63:005 states that open burning is prohibited. Open burning is defined as the burning of any matter in such a manner that the products of combustion resulting from the burning are emitted directly into the outdoor atmosphere without passing through a stack or chimney. However, open burning may be utilized for the purposes listed on the Open Burning Fact Sheet located at http://air.ky.gov/Pages/OpenBurning.aspx.

The Division would like to offer the following suggestions on how this project can help us stay in compliance with the NAAQS. More importantly, these strategies are beneficial to the health of citizens of Kentucky.

- Utilize alternatively fueled equipment.
- Utilize other emission controls that are applicable to your equipment.
- Reduce idling time on equipment.

The Division also suggests an investigation into compliance with applicable local government regulations.

2. The Division of Water offered the following comments.

An individual CWA Section 401 Water Quality Certification from the Division of Water is required for this project. Questions should be directed to Chloe Tewksbury at (502) 564-3410.

There are no Outstanding State Resource Waters, Wild River or Exceptional Waters within the project area. In-stream disturbances should be kept to a minimum. Questions should be directed to John Brumley at (502) 564-3410.

An application to Construct Across or Along a Stream will need to be submitted to the Division of Water Floodplain Section for further review of this project, per KRS 151.250. Questions should be directed to Julia Harrod at (502) 564-3410.

A Water Withdrawal Permit Application will need to be submitted to the Division of Water, per 401KAR4:010. Questions should be directed to Rita Hockensmith at (502) 564-3410. Information about this project is filed under AI118047, SunCoke Energy South Shore LLC. Application forms for Floodplain construction permitting and Water Withdrawal permitting are located on the Division of Water webpage at this address: http://water.ky.gov/permitting/Pages/default.aspx

The contractor's performing the construction may need a groundwater protection plan depending on the onsite activities. A Groundwater Protection Plan will be needed at the completed on shore facility for regulated activities. Questions should be directed to Phil O'Dell or Pat Keefe at (502) 564-3410.

3. The Kentucky State Nature Preserves Commission (KSNPC) offered the following comments.

Kentucky State Nature Preserves Commission (KSNPC) notes the presence of recorded locations of Northern leopard frog (*Rana pipiens*, KSNPC special concern) and Sedge Wren (*Cistothorus platensis*, KSNPC special concern) on the South Shore Wildlife Management Area which is just to the west of the proposed site. Possible habitat on the property that will be disturbed should be surveyed for the presence of these species. Questions should be directed to Tara Littlefield at (502) 573-2886.

If you have any additional questions, please contact me at (502) 564-2150.

Sincerely,

R. Bruce Scott
Commissioner

cc: Chloe Tewksbury, Division of Water
Mr. David Schwake/SunCoke Energy

Porter, Susan A

From:	Gruhala, James [james_gruhala@fws.gov]
Sent:	Thursday, May 16, 2013 3:28 PM
To:	Porter, Susan A
Subject:	Re: CELRH-RD-E Public Notice: LRH-2009-00264-OHR
Attachments:	2012-B-0707.PDF

Ms. Susan Porter
United States Army Corps of Engineers
502 8th Street
Huntington, West Virginia 25701-2070

Re: FWS 2012-B-0707; CELRH-RD-E Public Notice: LRH-2009-00264-OHR, SunCoke Energy South Shore, LLC, South Shore Facility Project, located in Greenup County, Kentucky

Dear Ms. Porter:

Please accept this correspondence and maintain for your records as the U.S. Fish and Wildlife Service's (Service) official response to the above-referenced Public Notice. The Service has reviewed the Public Notice and offers the following comments in accordance with the Endangered Species Act (ESA) of 1973 (87 Stat. 884, as amended; 16 U.S.C. 1531 et seq.).

Federally Listed Mussels
As stated in the Public Notice, a mussel survey was conducted in response to the Service's concerns regarding the potential for the proposed project-associated barge loading and fleeting facility to adversely affect federally listed mussels. The Service has previously reviewed the survey and concurred that the proposed project would likely adversely affect federally listed mussels. Our July 19, 2012 concurrence letter (attached) is based on the results of the mussel survey that was completed in September, 2008. Therefore, the Service concurs that the proposed project would not likely adversely affect federally listed mussels.

Gray bat (Myotis grisescens)
The Public Notice states that no suitable gray bat habitat is present within the proposed project area, and that the applicant will utilize best management practices during the construction of the facility. Based on this information, the Service concurs that the proposed project would not likely adversely affect the gray bat.

Indiana bat (Myotis sodalis)
The Public Notice indicates that approximately 45 acres of potential Indiana bat summer roost habitat (i.e., forested area) would be removed as a result of the proposed project, and that the applicant may be able to conduct all removal of trees between the dates of October 15 to March 31. This approach would avoid direct effects to Indiana bats that may be utilizing habitat within the project area during the timeframe when the species is anticipated to be present. If the project proponent cannot commit to this seasonal tree clearing restriction, the project area may be surveyed to determine if Indiana bats are present or absent.

The Service agrees with the planned approach to address the project's potential to adversely affect the Indiana bat. The Service also wants to inform the applicant of another available option that could be considered in lieu of seasonal clearing or surveying. The applicant could request entering into a Conservation Memorandum of Agreement (MOA) with the Service. By entering into a Conservation MOA with the Service, Cooperators gain flexibility in project timing with regard to the removal of suitable Indiana bat habitat. In exchange for this flexibility, the Cooperator provides recovery-focused conservation benefits to the Indiana bat through the implementation of minimization and mitigation measures as set forth in the Indiana Bat Mitigation Guidance for the Commonwealth of Kentucky. For additional information about this option, please notify our office.

Please inform us how the applicant wants to address the project's potential to adversely affect the Indiana bat. This is necessary before the Service can complete ESA section 7 consultation for the project and ensure that the proposed project would be in full compliance with the ESA.

Please contact me if you have any questions regarding our response. Refer to project number FWS-2012-B-0707.

Sincerely,

Jim Gruhala

James Gruhala
Fish & Wildlife Biologist
U.S. Fish & Wildlife Service
KY Ecological Services Field Office
330 West Broadway, Room 265
Frankfort, KY 40601

(502)695-0468 ext. 116

United States Department of the Interior

FISH AND WILDLIFE SERVICE
Kentucky Ecological Services Field Office
330 West Broadway, Suite 265
Frankfort, Kentucky 40601
(502) 695-0468

July 19, 2012

Mr. Benjamin Otto
Ecologist
URS Corporation
525 Vine Street, Suite 1800
Cincinnati, Ohio 45202

Re: FWS 2012-B-0707; URS Corporation, SunCoke Energy South Shore, LLC, South Shore Facility Project, located in Greenup County, Kentucky

Dear Mr. Otto:

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Common Name	**Scientific Name**	**Federal Status**
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The survey methods were approved by the Service and the Service believes that the survey effort covered the area of the Ohio River that would likely be significantly impacted by the proposed barge facility. According to the Report, the action area was surveyed on September 25, 2008. Divers had good visibility conditions. The survey methods consisted of a total of 8 transects plus a 15-minute qualitative search located in the area with the highest density of mussels. During the survey a total of 29 individual mussels were discovered representing 6 species. No federally listed mussels were found.

Based on the overall estimated mussel density and because no federally listed mussels were found, the Service concurs that the proposed project would not likely adversely affect the clubshell, fanshell, orangefoot pimpleback, pink mucket, ring pink, rough pigtoe, and sheepnose mussels.

Indiana bat

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If your project schedule requires the clearing of potential Indiana bat habitat (*i.e.*, trees that are greater than 5 inches DBH and exhibit any of the following characteristics: exfoliating bark, cracks, crevices, dead portions, cavities, broken limbs) during the period of April 1 to October 14, you have two primary options for addressing impacts to Indiana bats. First, you can survey the project site, or you can enter into a Conservation MOA with the Service. By entering into a Conservation MOA with the Service, Cooperators gain flexibility in project timing with regard to the removal of suitable Indiana bat habitat. In exchange for this flexibility, the Cooperator provides recovery-focused conservation benefits to the Indiana bat through the implementation of minimization and mitigation measures as set forth in the Indiana Bat Mitigation Guidance for the Commonwealth of Kentucky. For additional information about this option, please notify our office.

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gray bat

The federally endangered gray bat (*Myotis grisescens*) has been documented to occur within the vicinity of the proposed project area. Gray bats roost, breed, rear young, and hibernate in caves year round. They migrate between summer and winter caves and will use transient or stopover caves along the way. Gray bats eat a variety of flying aquatic and terrestrial insects present along streams, rivers, and lakes. Low-flow streams produce an abundance of insects, and are especially valuable to the gray bat as foraging habitat. For hibernation, the roost site must have an average temperature of 42 to 52 degrees F. Most of the caves used by gray bats for hibernation have deep vertical passages with large rooms that function as cold air traps. Summer caves must be warm, between 57 and 77 degrees F, or have small rooms or domes that can trap the body heat of roosting bats. Summer caves are normally located close to rivers or lakes where the bats feed. Gray bats have been known to fly as far as 12 miles from their colony to feed. Additional, habitat and life history information on these species is available on the Service's national website at www.fws.gov.

Because we have concerns relating to the gray bat on this project and due to the lack of occurrence information available on this species relative to the proposed project area, we have the following recommendations relative to gray bats.

1. Based on the presence of numerous caves, rock shelters, and underground mines in Kentucky, we believe that it is reasonable to assume that other caves, rock shelters, and/or abandoned underground mines may occur within the project area, and, if they occur, they could provide winter/summer habitat for gray bats. Therefore, we would recommend that the project proponent survey the project area for caves, rock shelters, and underground mines, identify any such habitats that may exist on-site, and avoid impacts to those sites pending an analysis of their suitability as gray bat habitat by this office.

2. Sediment Best Management Practices (BMPs) should be utilized and maintained to minimize siltation of the streams located within and in the vicinity of the project area, as these streams represent potential foraging habitat for the gray bat. A plan for BMP implementation should be submitted to our office for approval.

Thank you again for your request. Your concern for the protection of endangered and threatened species is greatly appreciated. If you have any questions regarding the information that we have provided, please contact James Gruhala at (502) 695-0468 extension 116.

Sincerely,

Virgil Lee Andrews, Jr.

Virgil Lee Andrews, Jr.
Field Supervisor

Steven L. Beshear
Governor

Leonard K. Peters
Secretary
Energy and Environment Cabinet

Donald S. Dott, Jr.
Director

Commonwealth of Kentucky
Kentucky State Nature Preserves Commission
801 Schenkel Lane
Frankfort, Kentucky 40601-1403
502-573-2886 Voice
502-573-2355 Fax

October 9, 2008

Sarah Polgar
URS Corporation
36 East Seventh Street, Suite 2300
Cincinnati, OH 45202

Data Request 09-035

Dear Ms. Polgar:

This letter is in response to your data request of September 29, 2008 for the Confidential Greenup County project. We have reviewed our Natural Heritage Program Database to determine if any of the endangered, threatened, or special concern plants and animals or exemplary natural communities monitored by the Kentucky State Nature Preserves Commission occur near the project area on the Portsmouth USGS Quadrangle, as shown on the map provided. Please see the attached reports for more information, which reflect analysis of the project area with three buffers applied:

1-mile for all records – 9 records
5-mile for aquatic records – 17 records
5-mile for federally listed species – 9 records
10-mile for mammals and birds – 1 record

Rana pipiens (Northern leopard frog, KSNPC Special Concern) occurs in this project area. The habitat for this species is springs, slow streams, marshes, bogs, ponds, canals, flood plains, reservoirs, and lakes; usually permanent water with rooted aquatic vegetation. In summer, commonly inhabits wet meadows and fields. Takes cover underwater, in damp niches, or in caves when inactive.

Please note that the vast majority of occurrences for aquatic organisms are from 1966 or earlier. This segment of the river has been severely impacted by pollutants. Although river quality is improving many if not all of these organisms apparently have been extirpated from the area.

I would like to take this opportunity to remind you of the terms of the data request license, which you agreed upon in order to submit your request. The license agreement states "Data and data products received from the Kentucky State Nature Preserves Commission, including any portion thereof, may not be reproduced in any form or by any means without the express written authorization of the Kentucky State Nature Preserves Commission." The exact location of plants, animals, and natural communities, if released by the Kentucky State Nature Preserves Commission, may not be released in any document or correspondence. These products are provided on a temporary basis for the express project (described above) of the requester, and may not be redistributed, resold or copied without the written permission of the Kentucky State Nature Preserves Commission's Data Manager (801 Schenkel Lane, Frankfort, KY, 40601. Phone: (502) 573-2886).

Please note that the quantity and quality of data collected by the Kentucky Natural Heritage Program are dependent on the research and observations of many individuals and organizations. In most cases, this information is not the result of comprehensive or site-specific field surveys; many natural areas in Kentucky have never been thoroughly surveyed, and new plants and animals are still being discovered. For these reasons, the Kentucky Natural Heritage Program cannot provide a definitive statement on the presence, absence, or condition of biological elements in any part of Kentucky. Heritage reports summarize the existing information known to the Kentucky Natural Heritage Program at the time of the request regarding the biological elements or locations in question. They should never be regarded as final statements on the elements or areas being considered, nor should they be substituted for on-site surveys required for environmental assessments. We would greatly appreciate receiving any pertinent information obtained as a result of on-site surveys.

If you have any questions or if I can be of further assistance, please do not hesitate to contact me.

Sincerely,

Sara Hines
Data Manager

SLD/SGH

Enclosures: Data Report and Interpretation Key

Donald S. Dott, Jr.
Director

Steven L. Beshear
Governor

Commonwealth of Kentucky
Kentucky State Nature Preserves Commission
801 Schenkel Lane
Frankfort, Kentucky 40601-1403
502-573-2886 Voice
502-573-2355 Fax

INVOICE

October 9, 2008

Sarah Polgar
URS Corporation
36 East Seventh Street, Suite 2300
Cincinnati, OH 45202

Purchase Order Number __________________ Data Request 09-035

This letter is an invoice for the amount of $____52.50______ for data services requested in your letter of October 8, 2008 for Confidential Greenup County project.

Please make payment to the Kentucky Nature Preserves Fund and include the Data Request number on your check. Payment is due upon receipt.

Please contact us if we can be of further assistance.

March 4, 2014

Mr. Richard A. Hemann
Regulatory Project Manager
Energy Resource Branch
USACE, Huntington District, CELRH-RD-E
502 8th Street
Huntington, WV, 25701

Re: Response to the State Historic Preservation Office of Kentucky Comments
Public Notice No. LRH-2009-00264-OHR
Proposed SunCoke Energy South Shore, LLC Facility
Greenup County, Kentucky

Dear Mr. Hemann,

On behalf of SunCoke Energy South Shore, LLC (SESS), this letter has been prepared to address comments provided by the State Historic Preservation Office of Kentucky (SHPO) in the attached correspondence dated June 11, 2013. The attached comments were submitted in response to Public Notice No. LRH-2009-00264-OHR associated with the Army Corps of Engineers (USACE) Section 10/404 Permit application for construction of a heat-recovery coke plant to be located near the city of South Shore in Greenup County, Kentucky. URS understands that the USACE received comments from parties who might be affected by the construction of the proposed facility, and has requested that responses be prepared to address each set of comments.

The attached letter indicates that the SHPO has concerns regarding the two sites that are eligible for listing in the National Register of Historic Places, 15Gp183 and 15Gp219, and which will be impacted by the proposed undertaking. Further, the SHPO understands from the Kentucky State Archaeologist, Dr. George Crothers, that there are concerns over potential impacts to other nearby resources—specifically those associated with the Portsmouth Earthwork Complex that are listed, eligible or potentially eligible for listing in the National Register. The SHPO shares Dr. Crothers concerns that potential impacts to these other resources should be fully considered and that any mitigation measures should take into account the relationship between 15Gp219 and the Portsmouth Earthwork complex. The SHPO supports the requests of Dr. George Crothers (Kentucky Office of State Archaeology) and the Ohio Archaeological Council to be consulting parties for this project.

URS understands that the SHPO shares certain observations listed by Dr. George Crothers in his letter dated June 5, 2013 (see attached), regarding sites in the vicinity of the Project. The purpose of this response is for URS to inform the USACE and the SHPO that the final mitigation plans for sites 15Gp219 and 15Gp183 will closely attend to the implications entailed by the proximity to the Project of various elements of the Portsmouth Earthworks (15Gp2, 15Gp8).

Following the recommendations of Dr. Crothers, URS (on behalf of SESS) has been in contact with Mr. Carl Shields, of the Kentucky Transportation Cabinet, and University of Kentucky graduate student Stuart Nealis, both of whom have been intimately involved in recent remote sensing and field survey in northern Greenup County. In these discussions URS was made aware of a 1932 aerial photograph that clearly shows parallel embankments analogous to those illustrated by Squire and Davis in 1848 (see Figure 1). The features revealed by this photography are unequivocally depicted on land not included in the Project APE, and which has been profoundly disturbed by the construction, use, and subsequent abandonment of a large industrial facility to the east of the proposed Project. This information, combined with the

URS Corporation
525 Vine Street, Suite 1800
Cincinnati, Ohio 45202
Tel: 513.651.3440
Fax: 877.660.7727

definition of the eastern limits of sites 15Gp183 and 15Gp219, indicates that neither site lies in proximity of less than 1,000 feet to the original embankment lines.

Additionally, Mr. Nealis informed URS of the recent confirmation of the location of Site 15Gp2 (Portsmouth Earthwork Group C), at a point approximately 1,000 feet further to the east than the location that has been until recently recorded within the Kentucky state site files. This new information increases the distance between this resource and the limits of the proposed SESS facility.

The current mitigation plan proposed for the project includes robust programs of hand and mechanical excavation, all to be allocated following the results of an extensive remote sensing survey of the 15Gp183 and 15Gp219 site areas. All investigations performed at these sites will be conducted with full awareness of the close proximity and singular archaeological significance of the Portsmouth Earthworks.

In regard to the mention by Dr. Crothers of recent LiDAR imagery shedding light on these issues, URS has been unable to identify any data of this sort that contributes positively to the understanding of the earthworks in the vicinity. The publically available LiDAR (see Figure 2) that has been acquired does not appear to show any sign of the earthworks under discussion, with the exception of the Biggs Mound (15Gp8), the location of which has been unequivocal.

As a point of clarification, Dr. Crothers' letter in one instance indicates that these embankments connected Portsmouth Earthworks Group C and Group D, which, if taken without consideration of additional locational information provided by Dr. Crothers, would suggest a crossing of the Project APE by the linear embankments. However, our review of the 1848 Squire and Davis map of the resource, as well as the previously mentioned 1932 aerial photography, indicates that the embankments, in fact, ran between Group C and Group B, which is situated on the Ohio side of the river.

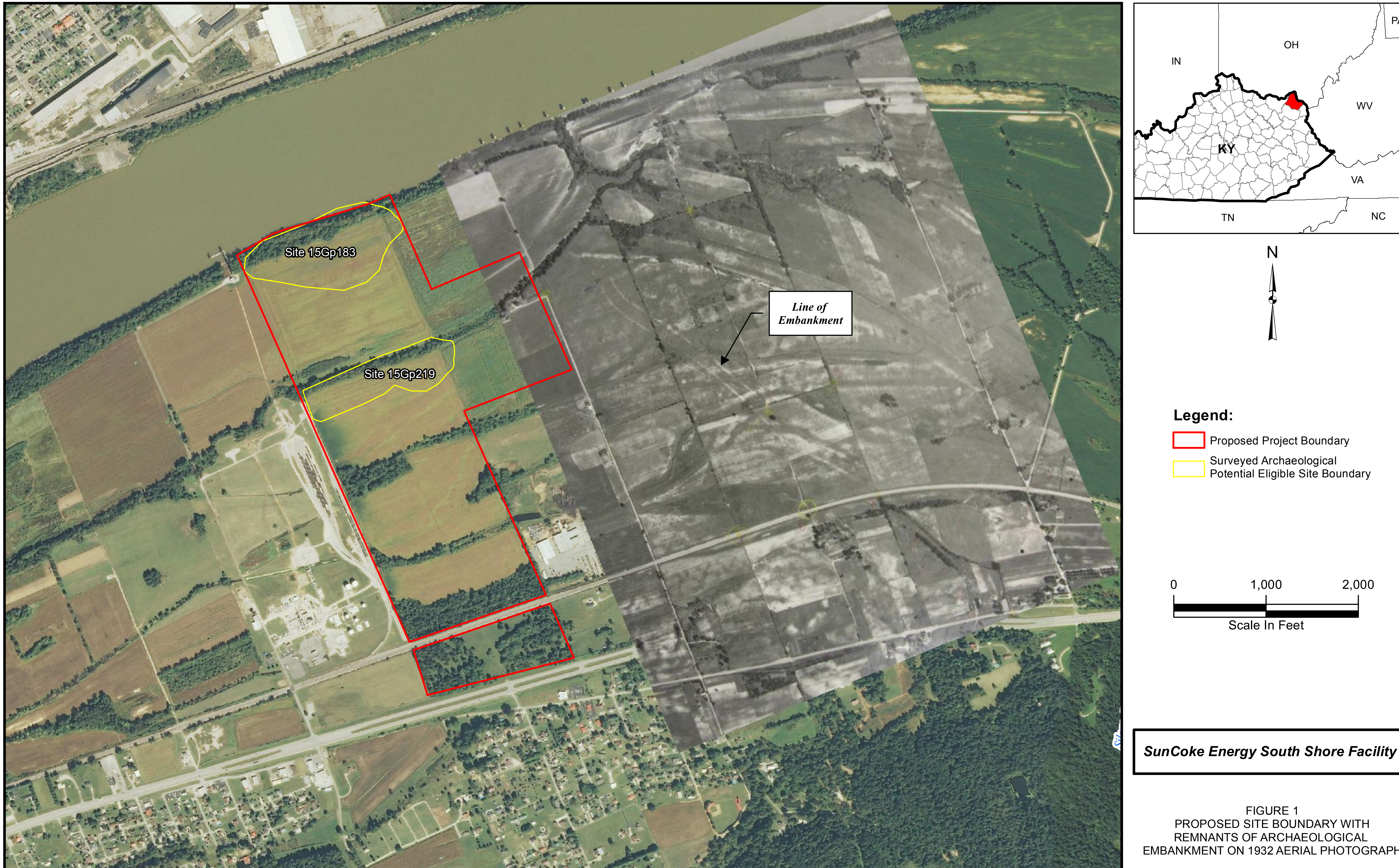
If you have any questions or require additional information, please feel free to contact the undersigned or Dave Schwake of SESS at (215) 384-5920.

Sincerely,

URS

Christopher A. Bergman, Ph.D.
Principal Archaeologist

Attachments: Figure 1
Figure 2
Kentucky Office of State Archaeology Letter dated June 5, 2013
State Historic Preservation Office of Kentucky Letter dated June 11, 2013



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SunCoke Energy South Shore Facility

FIGURE 1
PROPOSED SITE BOUNDARY WITH
REMNANTS OF ARCHAEOLOGICAL
EMBANKMENT ON 1932 AERIAL PHOTOGRAPH

JOB NO. 25368674

URS

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Legend:

Proposed Project Boundary

Surveyed Archaeological Potential Eligible Site Boundary

0 1,000 2,000

Scale In Feet

SunCoke Energy South Shore Facility

FIGURE 2
PROPOSED SITE BOUNDARY
WITH PORTSMOUTH EARTHWORKS
GROUP 'D' ON LiDAR IMAGERY

JOB NO. 25368674

URS

UNIVERSITY OF KENTUCKY

W.S. Webb Museum of Anthropology
Office of State Archaeology
College of Arts and Sciences
211 Lafferty Hall
Lexington, KY 40506-0024
(859) 257-8208
Fax (859) 323-1968
www.uky.edu

June 5, 2013

U.S. Army Corps of Engineers, Hunting District
ATTN: CELRH-RD-E Public Notice No. LRH-2009-00264-OHR
502 8th Street
Huntington WV 25701-2070

To whom it may concern:

This letter is in response to the Public Notice (No. LRH-2009-00264-OHR) regarding the proposed construction of the SunCoke Energy South Shore Facility industrial development. Archaeological testing at sites 15Gp183 and 15Gp219, which had been previously identified in the project area, determined these sites to be eligible for the National Register of Historic Places. The applicant proposes to conduct additional archaeological work on these sites to mitigate the proposed adverse impacts. My office supports the development of a mitigation plan for these sites; however, I would also like to point out some additional information that was not adequately considered in the Phase II NRHP eligibility testing of these sites by URS, Inc. of Cincinnati, Ohio.[1]

While no properties currently listed on the Register would be directly affected by the proposed work, the project areas is within the greater Portsmouth Earthworks region, one of the largest complex of mounds and earthworks known in the eastern U.S. The Portsmouth Earthworks consists of at least four mound groups encompassing both Ohio and Kentucky at the mouth of the Scioto River.[2] Group A or 15Gp1 (to the west of the project area) is the only group currently listed on the Register and is the best preserved portion of the complex. However, Group C (15Gp2) and Group D (15Gp7 and15Gp8) are both within 2000 to 3000 feet of the proposed development. Both groups were considered to be potentially eligible for the Register, but were not nominated at the time with 15Gp1. Another important feature of the Portsmouth Earthworks is a series of low earthen embankments that linked the separate mound groups. In particular, one line of embankments runs from Group C (15Gp2) to Group D, which is located across the river in the city of Portsmouth, Ohio, and comes extremely close to the proposed project area. The location of these embankments has not been verified in the field, but portions do show up in older aerial photographs and in more recent LiDAR coverages of the area. Any Phase III mitigation plan should consider whether these embankments will be adversely impacted and also consider the relationship of site 15Gp219 to the greater Portsmouth Earthwork complex.

In conclusion, because of the national significance of the Portsmouth Earthworks in understanding the complexity of the Hopewell cultural phenomenon and the fact that very few portions of the earthworks or associated sites have been adequately studied, the Kentucky Office of State Archaeology would like to be considered as a potential consulting party and wishes to participate in addressing the proposed adverse effects to these historical properties.

Please let me know if I may be of additional assistance in this matter.

Most sincerely yours,

George M. Crothers, Ph.D.
Director

cc. Craig Potts, State Historic Preservation Office, Frankfort.

1. Duerksen, Ken, and Christopher Bergman, 2011, Phase II NRHP Eligibility Testing of Sites 15GP183 and 15GP219 in Greenup County, Kentucky. Submitted to SunCoke Energy, Inc., Lisle, Illinois. Report submitted by URS, Inc. Cincinnati, Ohio.
2. Squier, Ephraim G., and Edwin H. Davis, 1848, The Portsmouth Works, Scioto County, Ohio. In *Ancient Monuments of the Mississippi Valley*, pp. 77-82. Reprinted in 1998 by Smithsonian Institution Press, Washington, DC.

STEVEN L. BESHEAR
GOVERNOR

TOURISM, ARTS AND HERITAGE CABINET
KENTUCKY HERITAGE COUNCIL

BOB STEWART
SECRETARY

THE STATE HISTORIC PRESERVATION OFFICE
300 WASHINGTON STREET
FRANKFORT, KENTUCKY 40601
PHONE (502) 564-7005
FAX (502) 564-5820
www.heritage.ky.gov

CRAIG POTTS
EXECUTIVE DIRECTOR AND
STATE HISTORIC PRESERVATION OFFICER

June 11, 2013

US Army Corps of Engineers, Huntington District
ATTN: CELRH-RD-E
Susan Porter
502 8th Street
Huntington, WV 25701-2070

Re: LRL-2009-00264-OHR
SunCoke Energy Project
Greenup County

Dear Ms. Porter:

Please accept this response regarding the Public Notice for the above-listed Corps Permit. From the Public Notice, we understand that two sites that are eligible for listing in the National Register of Historic Places, 15Gp183 and 15Gp219, will be impacted by the proposed undertaking. Further, we understand from the Kentucky State Archaeologist, Dr. George Crothers, that there are concerns over potential impacts to other nearby resources—specifically those associated with the Portsmouth Earthwork Complex that are listed, eligible or potentially eligible for listing in the National Register. We share Dr. Crothers concerns that potential impacts to these other resources should be fully considered and that any mitigation measures should take into account the relationship between 15Gp219 and the Portsmouth Earthwork complex.

If impacts to 15Gp183, 15Gp219, or other sites that may be listed or eligible for the National Register cannot be avoided, we look forward to coordinating with the Corps, the applicant, and other consulting parties regarding the development of appropriate mitigations measures and the Memorandum of Agreement. While the proposed measures identified by the applicant in the Public Notice (i.e., geophysical survey, hand excavation, and controlled mechanical excavation) are likely components of that mitigation effort, additional measures may also be warranted pending the results of the consultation process. Further, we support the requests of Dr. George Crothers (Kentucky Office of State Archaeology) and the Ohio Archaeological Council to be consulting parties for this project. Should you have any questions, feel free to contact Kary Stackelbeck of my staff at 564-7005, ext. 115.

Sincerely,

Craig Potts
Executive Director and
State Historic Preservation Officer

CP:kls
cc: Dr. George Crothers (OSA); Al Tonetti (Ohio Archaeological Council)

March 4, 2014

Mr. Richard A. Hemann
Regulatory Project Manager
Energy Resource Branch
USACE, Huntington District, CELRH-RD-E
502 8th Street
Huntington, WV, 25701

Re: Response to the Ohio Archaeological Council (Lynn M. Hanson, M.A.) Comments
Public Notice No. LRH-2009-00264-OHR
Proposed SunCoke Energy South Shore, LLC Facility
Greenup County, Kentucky

Dear Mr. Hemann,

On behalf of SunCoke Energy South Shore, LLC (SESS), this letter has been prepared to address comments provided by the Ohio Archaeological Council (OAC) in the attached correspondence by Ms. Lynn M. Hanson, M.A., dated May 15, 2013. The attached comments were submitted in response to Public Notice No. LRH-2009-00264-OHR associated with the Army Corps of Engineers (USACE) Section 10/404 Permit application for construction of a heat-recovery coke plant to be located near the city of South Shore in Greenup County, Kentucky (the Project). URS understands that the USACE received comments from parties who might be affected by the construction of the proposed facility, and has requested that responses be prepared to address each set of comments.

The attached letter indicates that the OAC has concerns regarding the two sites that are eligible for listing in the National Register of Historic Places, 15Gp183 and 15Gp219, which will be impacted by the proposed undertaking.

SESS and URS would like to thank Ms. Hanson and the OAC for their interest in the Project, and in the cultural resources located in its vicinity. URS has been the cultural resources consultant for the Project since 2009, when the firm was contracted to conduct Phase II investigations on sites 15Gp219 and 15Gp183. To date, URS has conducted no cultural resources fieldwork for this Project in Ohio. However, minor construction associated with the project will occur in Ohio which will primarily involve the installation of three transmission line poles. Once the location of these poles has been finalized, cultural resources fieldwork will be performed to address these locations. SESS recognizes the concerns of the OAC, and would like to inform the organization that URS is working closely with Dr. George Crothers, State Archaeologist, as well as the staff of the Kentucky Heritage Council.

Ms. Hanson's letter also requests electronic copies of the cultural resources reports associated with the Project. URS suggests that the OAC direct its inquiries in this regard to your office. If such distribution is acceptable to the USACE, URS would be pleased to assist in their transmittal.

URS Corporation
525 Vine Street, Suite 1800
Cincinnati, Ohio 45202
Tel: 513.651.3440
Fax: 877.660.7727

If you have any questions or require additional information, please feel free to contact the undersigned or Dave Schwake of SESS at (215) 384-5920.

Sincerely,

URS

Christopher A. Bergman, Ph.D.
Principal Archaeologist

Attachment: The Ohio Archaeological Council Letter dated May 15, 2013

THE OHIO ARCHAEOLOGICAL COUNCIL
P.O. BOX 82012 • COLUMBUS, OHIO 43202

May 15, 2013

U.S. Army Corps of Engineers, Huntington District
ATTN: CELRH-RD-E, Public Notice Number LRH-2009-00264-OHR
502 8th St.
Huntington, WV 25701-2070

Re: SunCoke Energy South Shore Facility

Pursuant to Public Notice LRH-2009-00264-OHR, the Ohio Archaeological Council requests consulting party status in the SunCoke Energy South Shore Facility undertaking. Although only a small portion of this undertaking is in Ohio (installation of a new 138 kV transmission line), and the rest on the Ohio River floodplain in Kentucky, the adverse effects of the undertaking on the two historic properties of archaeological significance, 15Gp183 and 15Gp219, are of concern and interest to the Ohio Archaeological Council. Please send electronic copies of the Phase I and Phase II archaeological investigations for this undertaking to my attention at the above address. Please address future correspondence concerning mitigating adverse effects to these historic properties to the attention of Al Tonetti, Chair, Government Affairs Committee, at the above address, or to atonetti@ascgroup.net.

Sincerely,

Lynn M. Hanson

Lynn M. Hanson, M.A.
President, Ohio Archaeological Council
(937) 275-7431
lynn.hanson0301@yahoo.com

c: Mark Epstein, Ohio Historic Preservation Office, 800 E. 17th Ave., Columbus, OH 43211
Craig Potts, Kentucky Heritage Council, 300 Washington St., Frankfort, Kentucky 40601

March 4, 2014

Mr. Richard A. Hemann
Regulatory Project Manager
Energy Resource Branch
USACE, Huntington District, CELRH-RD-E
502 8th Street
Huntington, WV, 25701

Re: Response to Kentucky Office of State Archaeology Comments
Public Notice No. LRH-2009-00264-OHR
Proposed SunCoke Energy South Shore, LLC Facility
Greenup County, Kentucky

Dear Mr. Hemann,

On behalf of SunCoke Energy South Shore, LLC (SESS), this letter has been prepared to address comments provided by Dr. George Crothers, Kentucky State Archaeologist, in the attached correspondence dated June 5, 2013. The attached comments were submitted in response to Public Notice No. LRH-2009-00264-OHR associated with the Army Corps of Engineers (USACE) Section 10/404 Permit application for construction of a heat-recovery coke plant to be located near the city of South Shore in Greenup County, Kentucky. URS understands that the USACE received comments from parties who might be affected by the construction of the proposed facility, and has requested that responses be prepared to address each set of comments.

The attached letter indicates Dr. Crothers' concurrence with SESS' determination that sites 15Gp183 and 15Gp219, which had been previously identified in the project area, would be eligible for the National Register of Historic Places. Dr. Crothers supports SESS' proposal to conduct additional archaeological work on these sites to mitigate the proposed adverse impacts. Dr. Crothers also pointed out some additional information that was not adequately considered in the Phase II NRHP eligibility testing of these sites by URS Corporation of Cincinnati, Ohio.

Although Dr. Crothers acknowledges that no properties currently listed on the Register would be directly affected by the proposed work, he does indicate that the project area is within the greater Portsmouth Earthworks region, one of the largest complexes of mounds and earthworks known in the eastern United States. Dr. Crothers explains that the Portsmouth Earthworks consists of at least four mound groups encompassing both Ohio and Kentucky at the mouth of the Scioto River. Group A or 15Gpl (to the west of the project area) is the only group currently listed on the Register and is the best preserved portion of the complex. However, Group C (15Gp2) and Group D (15Gp7 and 15Gp8) are both within 2,000 to 3,000 feet of the proposed development. Dr. Crothers states that both groups were considered to be potentially eligible for the Register, but were not nominated at the time with i5Gpl. According to Dr. Crothers, another important feature of the Portsmouth Earthworks is a series of low earthen embankments that linked the separate mound groups. In particular, one line of embankments runs from Group C (15Gp2) to Group D, which is located across the river in the city of Portsmouth, Ohio, and comes extremely close to the proposed project area. Dr. Crothers indicates that the location of these embankments has not been verified in the field, but portions show up in older aerial photographs and in more recent LiDAR coverage of the area. Dr. Crothers requests that any Phase III mitigation plan should consider whether these embankments will be adversely impacted and also considers the relationship of site 15Gp219 to the greater Portsmouth Earthwork complex.

URS Corporation
525 Vine Street, Suite 1800
Cincinnati, Ohio 45202
Tel: 513.651.3440
Fax: 877.660.7727

Dr. Crothers states that because of the national significance of the Portsmouth Earthworks in understanding the complexity of the Hopewell cultural phenomenon and the fact that very few portions of the earthworks or associated sites have been adequately studied, the Kentucky Office of State Archaeology would like to be considered as a potential consulting party and wishes to participate in addressing the proposed adverse effects to these historical properties.

Dr. Crothers' letter recognizes that no properties listed on the NRHP will be directly affected by the proposed project, and also discusses the proximity of elements of the Portsmouth Earthworks complex, which occupies portions of the Ohio River valley floor in the Project vicinity. Dr. Crothers' letter also identifies other data sets that may be available to aid in the assessment of potential impacts to cultural resources from the proposed Project. The purpose of this response is to identify the efforts and results of the search by SESS and URS for information in this regard.

As Dr. Crothers suggested, URS (on behalf of SESS) has been in contact with Mr. Carl Shields, of the Kentucky Transportation Cabinet, and University of Kentucky graduate student Mr. Stuart Nealis, both of whom have been intimately involved in recent remote sensing and field survey in northern Greenup County. In these discussions, URS was made aware of a 1932 aerial photograph that clearly shows parallel embankments analogous to those illustrated by Squire and Davis in 1848 (see Figure 1). The features revealed by this photography are unequivocally depicted on land not included in the Project APE, and which has been profoundly disturbed by the construction, use, and subsequent abandonment of a large industrial facility to the east of the proposed SESS project. This information, combined with the definition of the eastern limits of sites 15Gp183 and 15Gp219, indicates that neither site lies in proximity of less than 1,000 feet to the original embankment lines.

Additionally, Mr. Nealis informed URS of the recent confirmation of the location of Site 15Gp2 (Portsmouth Earthwork Group C), at a point approximately 1,000 feet further to the east than the location that has been until recently recorded within the Kentucky state site files. This new information increases the distance between this resource and the limits of the proposed SESS facility.

The current mitigation plan proposed for the Project includes robust programs of hand and mechanical excavation, all to be allocated following the results of an extensive remote sensing survey of the 15Gp183 and 15Gp219 site areas. All investigations performed at these sites will be conducted with full awareness of the close proximity and singular archaeological significance of the Portsmouth Earthworks.

In regard to Dr. Crothers letter's mention of recent LiDAR imagery shedding light on these issues, URS has been unable to identify any data of this sort that contributes positively to the understanding of the earthworks in the vicinity. The publically available LiDAR (see Figure 2) that has been acquired does not appear to show any sign of the earthworks in question, with the exception of the Biggs Mound (15Gp8), the location of which has been unequivocal. We would greatly appreciate any further information you could provide in this regard.

As a point of clarification, your letter in one instance indicates that these embankments connected Portsmouth Earthworks Group C and Group D, which, if considered in the absence of additional locational information you provide, would suggest a crossing of the Project APE by the linear embankments. However, review of the 1848 Squire and Davis map of the resource, as well as the previously mentioned

1932 aerial photography, indicates that the embankments in fact ran between Group C and Group B, which is situated on the Ohio side of the river.

If you have any questions or require additional information, please feel free to contact the undersigned or Dave Schwake of SESS at (215) 384-5920.

Sincerely,

URS

Christopher A. Bergman, Ph.D.
Principal Archaeologist

Attachments: Figure 1
Figure 2
Kentucky Office of State Archaeology Letter dated June 5, 2013

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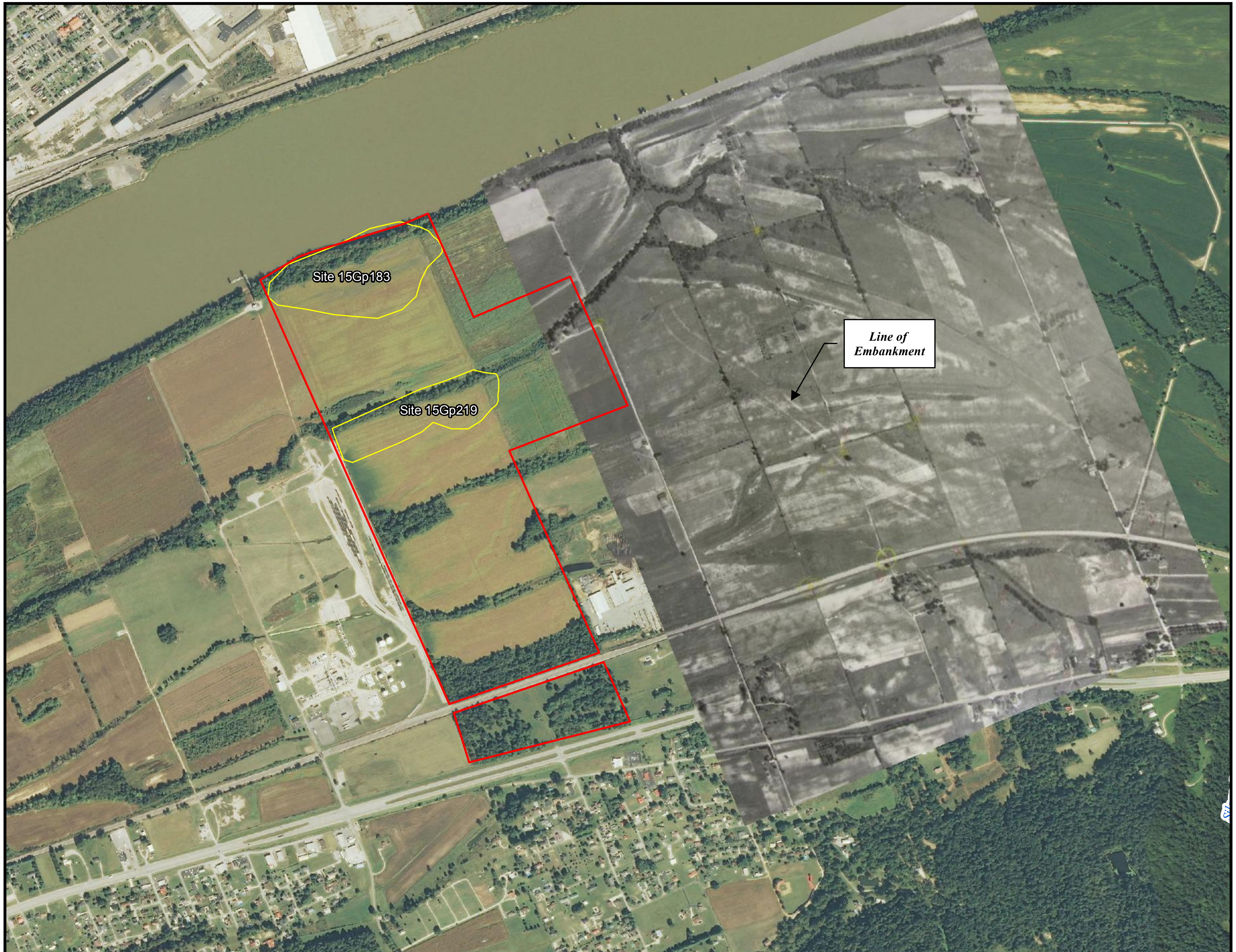

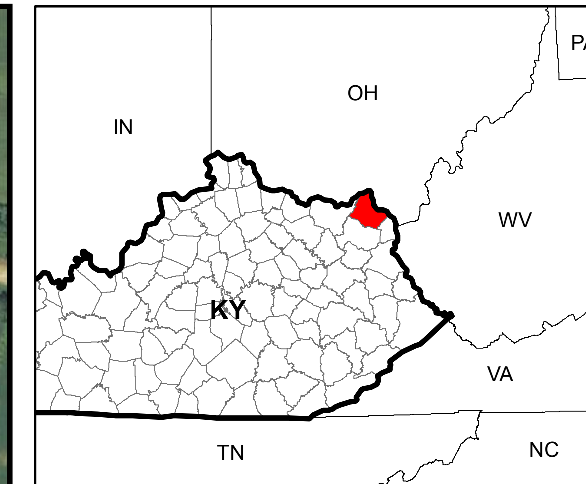

N

Legend:

Proposed Project Boundary

Surveyed Archaeological Potential Eligible Site Boundary

0 1,000 2,000

Scale In Feet

SunCoke Energy South Shore Facility

FIGURE 1
PROPOSED SITE BOUNDARY WITH
REMNANTS OF ARCHAEOLOGICAL
EMBANKMENT ON 1932 AERIAL PHOTOGRAPH

JOB NO. 25368674

URS

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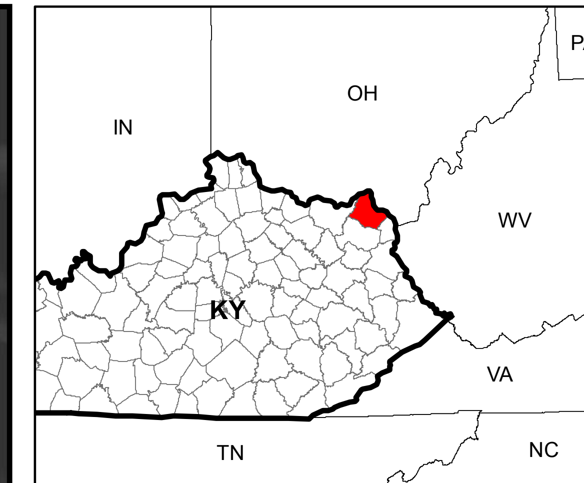

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Legend:

Proposed Project Boundary

Surveyed Archaeological Potential Eligible Site Boundary

0 1,000 2,000

Scale In Feet

SunCoke Energy South Shore Facility

FIGURE 2
PROPOSED SITE BOUNDARY
WITH PORTSMOUTH EARTHWORKS
GROUP 'D' ON LiDAR IMAGERY

JOB NO. 25368674

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UNIVERSITY OF KENTUCKY

W.S. Webb Museum of Anthropology
Office of State Archaeology
College of Arts and Sciences
211 Lafferty Hall
Lexington, KY 40506-0024
(859) 257-8208
Fax (859) 323-1968
www.uky.edu

June 5, 2013

U.S. Army Corps of Engineers, Hunting District
ATTN: CELRH-RD-E Public Notice No. LRH-2009-00264-OHR
502 8th Street
Huntington WV 25701-2070

To whom it may concern:

This letter is in response to the Public Notice (No. LRH-2009-00264-OHR) regarding the proposed construction of the SunCoke Energy South Shore Facility industrial development. Archaeological testing at sites 15Gp183 and 15Gp219, which had been previously identified in the project area, determined these sites to be eligible for the National Register of Historic Places. The applicant proposes to conduct additional archaeological work on these sites to mitigate the proposed adverse impacts. My office supports the development of a mitigation plan for these sites; however, I would also like to point out some additional information that was not adequately considered in the Phase II NRHP eligibility testing of these sites by URS, Inc. of Cincinnati, Ohio.[1]

While no properties currently listed on the Register would be directly affected by the proposed work, the project areas is within the greater Portsmouth Earthworks region, one of the largest complex of mounds and earthworks known in the eastern U.S. The Portsmouth Earthworks consists of at least four mound groups encompassing both Ohio and Kentucky at the mouth of the Scioto River.[2] Group A or 15Gp1 (to the west of the project area) is the only group currently listed on the Register and is the best preserved portion of the complex. However, Group C (15Gp2) and Group D (15Gp7 and15Gp8) are both within 2000 to 3000 feet of the proposed development. Both groups were considered to be potentially eligible for the Register, but were not nominated at the time with 15Gp1. Another important feature of the Portsmouth Earthworks is a series of low earthen embankments that linked the separate mound groups. In particular, one line of embankments runs from Group C (15Gp2) to Group D, which is located across the river in the city of Portsmouth, Ohio, and comes extremely close to the proposed project area. The location of these embankments has not been verified in the field, but portions do show up in older aerial photographs and in more recent LiDAR coverages of the area. Any Phase III mitigation plan should consider whether these embankments will be adversely impacted and also consider the relationship of site 15Gp219 to the greater Portsmouth Earthwork complex.

In conclusion, because of the national significance of the Portsmouth Earthworks in understanding the complexity of the Hopewell cultural phenomenon and the fact that very few portions of the earthworks or associated sites have been adequately studied, the Kentucky Office of State Archaeology would like to be considered as a potential consulting party and wishes to participate in addressing the proposed adverse effects to these historical properties.

Please let me know if I may be of additional assistance in this matter.

Most sincerely yours,

George M. Crothers, Ph.D.
Director

cc. Craig Potts, State Historic Preservation Office, Frankfort.

[1.] Duerksen, Ken, and Christopher Bergman, 2011, Phase II NRHP Eligibility Testing of Sites 15GP183 and 15GP219 in Greenup County, Kentucky. Submitted to SunCoke Energy, Inc., Lisle, Illinois. Report submitted by URS, Inc. Cincinnati, Ohio.

[2.] Squier, Ephraim G., and Edwin H. Davis, 1848, The Portsmouth Works, Scioto County, Ohio. In *Ancient Monuments of the Mississippi Valley*, pp. 77-82. Reprinted in 1998 by Smithsonian Institution Press, Washington, DC.

Commonwealth of Kentucky
Division for Air Quality

COMMENTS AND RESPONSES

ON THE DRAFT PERMIT

NOTE: ALL COMMENTS ARE IN ITALICS

Comments on SunCoke Energy South Shore (SESS), Inc. Draft Title V/Title 1 PSD Construction/Operating Air Quality Permit submitted by David J. Schwake, Director, North America, Business Development, SunCoke Energy, Inc.

PERMIT STATEMENT OF BASIS:

See Attachment #1 below for Comments #1-21 by SESS on Statement of Basis

1. Page 2, Source Description – In paragraph four, the language "Each of the two flat push hot cars…" should be changed to "The flat push hot car…"

Division's Response: The Division concurs and has amended the Statement of Basis.

2. Page 3, Source Description – In paragraph one, the language "…due mostly to the use of natural gas as a fuel,…" should be removed.

Division's Response: The Division concurs and has amended the Statement of Basis.

3. Page 6, Applicable Regulations – In paragraph one, 401 KAR 63:010, Fugitives, the language "… and EU19 (Cooling Tower)," should be removed.

Division's Response: The Division concurs and has amended the Statement of Basis and permit.

4. Page 6, Applicable Regulations – In paragraph three, 401 KAR 59:105, New process gas streams the language "…and EU26 (Emergency Stacks/Lids) with respect to SO_2, only." should be removed as it is not applicable to this emissions unit.

Division's Response: The Division concurs and has amended the Statement of Basis.

5. Page 6, Non-Applicable Regulations – The cooling tower unit number is EU19, not EU17.

Division's Response: The Division concurs and has amended the Statement of Basis.

6. Page 7, Table 1 – Revise the Potential To Emit (PTE) totals for most pollutants to match the values from the application and supplemental information. Page 7, Paragraph two, The Group I – Revise the estimated tpy for PM, PM_{10}, and $PM_{2.5}$ to reflect changes suggested for Table I.

Division's Response: The Division partially concurs and the Statement of Basis has been amended. Some changes were made to emission factors based on comments from SESS and the potential emission numbers have been changed.

7. Pages 7 through 14 of The Statement of Basis – Revise emissions estimates for each pollutant for various equipment groups (PM, PM_{10}, $PM_{2.5}$, CO, VO, NOx, Pb, and GHGs) to match the emission number changes suggested for TABLE I.

Division's Response: The Division partially concurs. See response to comment 6, above.

8. Pages 9-12,All Stationary Internal Combustion Engines – Emissions of NOx, CO, PM, and VOC should be calculated using emission factors obtained from 40 CFR 60 Subpart IIII.

Division's Response: The Division concurs and accepts the speciation of NOx and VOC emission factors (88 percent and 12 percent, respectively) from the combined emission factor referenced by 40 CFR 60 Subpart IIII. Emission calculations have been updated to reflect this change.

9. Page 9, Carbon Monoxide (CO) – In the section's paragraph, the language "There are no controls for CO in this group of equipment…" should be changed to "Controls for CO in this group of equipment are based on good combustion practices."

Division's Response: The Division concurs and has amended the Statement of Basis.

10. Page 12, Lead (Pb) – In the section's paragraph, the language "…and the Natural Gas Lances/Spargers (EU11…" should be removed.

Division's Response: The Division does not concur. The use of natural gas causes small emissions of Pb according AP-42, Table 1.4.1-2. No change has been made.

11. Page 23, Group V: Storage Silos (EU20, EU21, and EU22) – In the section's fourth paragraph, the language "…For the Lime Silo (EU20), the limits are 0.2340…" should be changed to "For the Lime (EU20), the limits are 0.2354…"

Division's Response: The Division concurs and has amended the permit. Additionally, the word "Storage" was added between the words "Lime" and "Silo", i.e. "Lime Storage Silo", to reflect the permit name of the equipment.

12. Page 26, Quench Tower (EU09) – In the page's third paragraph, the language "…PM_{10}, and $PM_{2.5}$…" should be removed.

Division's Response: The Division concurs and has amended the Statement of Basis.

13. Page 27, Coking (EU07) – In the page's top paragraph, the language "…coil-fired…" should be corrected to "…coal-fired…"

Division's Response: The Division concurs and has amended the Statement of Basis.

14. Page 28, Coal Charging East and West (EU05, EU06) – In the page's third paragraph, the language "…limits of 0.002 lb/ton of dry coal for CO and 0.0023 lb/ton of dry coal…" should be *changed to "…limits of 0.0028 lb/ton of wet coal for CO and 0.0023 lb/ton of wet coal…".*

Division's Response: The Division concurs and has amended the Statement of Basis.

15. Page 29, Coke Pushing (EU08) – In the page's top paragraph, the number "…867,477…" should be corrected to "…867,447…"

Division's Response: The Division concurs and has amended the Statement of Basis.

16. Page 30, Coking (EU07) – In the page's second full paragraph, the words "…in specific, …" should be removed.

Division's Response: The Division concurs and has amended the Statement of Basis.

17. Page 32, Coal Charging East and West (EU05, EU06) and Coke Pushing (EU08) – In the page's top paragraph, the BACT emission limit "…0.0003 lb/ton dry coal for Charging…" should be corrected to "…0.0003 lb/ton wet coal for Charging…"

Division's Response: The Division concurs and has amended the Statement of Basis.

18. Page 33, Coking (EU07) – In the page's third full paragraph, the language "…with the CEMs providing for continuous…"should be changed to "…with monitoring the coal sulfur content providing for continuous…"

Division's Response: The Division acknowledges the comment and has changed both the Statement of Basis and the permit. The Division has rewritten the section to explain how the CEMs, and adherence to the CAM plan for SO_2, provides adequate assurance of compliance with the BACT limits for H_2SO_4.

The paragraph now reads:

> The permit also establishes BACT limits for H_2SO_4 from Coking (EU07) of 6.2 lb/hr and 27 tpy. Initial compliance is established by stack test. Continuous compliance is determined by midterm testing and SO_2 CEMs in conjunction with the correlation between SO_2 and H_2SO_4 emissions developed according to the Compliance Demonstration with **2. Emission Limitations** for this emission unit. The permit also includes monitoring and recordkeeping requirements to ensure that the emission limits are being met.

See Comment 29, for the permit, below.

19. Page 37, Coal Charging East and West (EU05, EU06) and Coke Pushing (EU08) – In the last paragraph, the number "…867,477…" should be corrected to "…867,447…"

Division's Response: The Division concurs and has amended the Statement of Basis.

20. Page 46, Group VII Diesel Engines >500 and = <800 HP, Cranes E and F (EU28, EU29)

– In the second paragraph, the number "…5400 tpy for EU28…" should be corrected to "…5,430 tpy for EU28…"

Division's Response: The Division concurs and has amended the Statement of Basis.

21. Page 47, I. BACT SUMMARY: Table 5, Fugitive PM/PM10/Pm2.5 – In the BACT Determination column, the number for Fugitive PM/PM10/PM2.5 for the Cooling Tower (EU19) the number "...Maximum 0.005% drift…" should be corrected to "...Maximum 0.0005% drift…"

Division's Response: The Division concurs and has amended the Statement of Basis.

TITLE V PERMIT (V-13-007):

See Attachment #2 below for Comments #22-71 by SESS on Draft Title V Permit

22. Section B, 3.b; page 8 – add text from 40 CFR 60.255(f)(2) in item 3.b.

Division's Response: The Division concurs and has amended the permit.

23. Section B, 1. e; page 13 – Remove the word "that" as it is extraneous.

Division's Response: The Division concurs and has amended the permit.

24. Section B, 2. b.; page13 – Omitted digit (0.0028) in CO factor and emission factors other than PM are per wet ton coal…"

Division's Response: The Division concurs and has amended the permit.

25. Section B, 2. c. (1); page 14 – Clarify specific emission unit to which this requirement applies. Replace "any affected facility" with "the pushing/charging machine."

Division's Response: The Division concurs and has amended the permit.

26. Section B,6. b.; page17 – Design changes may go through several iterations and it may not be possible to provide the final version of a change within 30 days after the design is changed. Request that the "30 days" be changed to "a reasonable time".

Division's Response: The Division acknowledges the comment. The purpose of including the time requirement was to ensure the Division is notified of changes so an analysis of possible impacts on air emissions and original permit conditions may be completed before construction of the design change. Allowing for submittal in "a reasonable time" is not enforceable. Therefore, the Division has changed the time element to "prior to construction", but has added a requirement that an analysis of impact to air emissions and to the permit be submitted with the design change(s) prior to construction of the design change.

The new paragraph shall read:

> *The permittee shall submit certification that the design elements proposed as BACT for the emission unit or process have been implemented in the final construction. Any deviations from the design elements proposed in the application shall be analyzed for changes in air emissions profile and potential impact to permit requirements and/or conditions. Design changes and analyses shall be submitted in a report to the Division prior to construction of the changed element.*

27. and 28. Section B, 2. b. (1); page 21 – CDS will be designed to meet 134 lb SO_2/hr under all conditions. Revise to match CAM plan." Also, add new requirement to clarify that BACT limit is to be demonstrated through performance testing.

Division's Response: The Division concurs with the comment and has amended the permit to clarify the requirements for each "type" of SO_2 emission limit, i.e. The CEMS is used to show continuous compliance with the 134 lb/hr requirement, while performance testing is used to show initial compliance with 0.96 lb/ton of wet coal requirement.

29. Section B, 2. b. (1); page 21 – There are no commercially available H_2SO_4 CEMs. However, H_2SO_4 emissions will be limited by coal sulfur content (and controlled by the CDS along with SO_2).

Division's Response: The Division concurs and has amended the permit and Statement of Basis, however, the SO_2 CEMs will be used for monitoring continuous compliance with the H_2SO_4 BACT limit.

The wording and continuous compliance demonstration for H_2SO_4 in the permit have been changed to:

> Continuous compliance with the H_2SO_4 emission limits is demonstrated by complying with the SO_2 emission limit. Therefore, continuous compliance with the H_2SO_4 emission limit is demonstrated through the Continuous Emissions Monitoring of SO_2 and the relationship established during performance testing as required by **3. Testing Requirements,** item **e**, below. Additionally, proper maintenance of control equipment for sulfur oxide emissions ensures continual adherence to the H_2SO_4 emission limits. Therefore, observation of the CAM plan for the CDS also provides a demonstration of continuous compliance with this limit. See **4. Specific Monitoring Requirements**, items **h** through **k**, below.

Finally, mention of H_2SO_4 has been removed from subsequent permit terms about the CEMs. See Comments 32, 33, 34, and 35, below.

Note: Added **4. Specific Monitoring Requirements**, item **k**:

k. The permittee shall ensure that the scrubbing liquor flow rate through the CDS is maintained in the range established during the performance test for this equipment or in accordance with the manufacturer's specifications. See Section D – Source Emissions Limitations and Testing Requirements, item **6**.

The following language is added regarding H_2SO_4 compliance:

> Initial compliance with the BACT limit of 6.2 lb/hr of H_2SO_4 shall be demonstrated through performance testing. The permittee shall perform a subsequent performance test at the mid-term of the permit. Following each performance test the permittee shall establish the correlation between emissions of SO_2 and H_2SO_4. The permittee may use concurrent SO_2 RATA testing during mid-term to establish correlation. The established correlation shall be used in calculating emissions for compliance demonstration.

30. Section B, 3. d.; page 24 – CDS will be designed to meet 0.96 lb SO_2/ton wet coal at normal conditions that create the highest rate of emissions.

Division's Response: The Division concurs and has amended the permit.

31. Section B, 4. h.; page 25 – Delete reference to H_2SO_4 CEM. Use CFR citation that matches CAM plan.

Division's Response: Comment acknowledged, reference removed and CFR citation changed. See answer to comment 29, above.

32. Section B, 4. i.; page 25 – Delete references to H_2SO_4 CEM.

Division's Response: Comment acknowledged, reference removed. See answer to comment 29, above.

33. Section B, 4. j.; page 25 – Delete reference to H_2SO_4 CEM. Revise CFR reference for CEM performance specifications.

Division's Response: Comment acknowledged, reference removed, CFR citation changed as requested. See answer to comment 29, above.

34. Section B, 6. b.; page 27 – Any change in design will go through several iterations. It may not be possible to provide this within 30 days.

Division's Response: See Division's response to comment 26, above.

35. Section B, 6. d.; page 27 – Duplicate term. Remove.

Division's Response: Comment acknowledged, duplicate removed. Lettering changes also made.

36. Section B, 6. f. (2); page 27 – Delete reference to H_2SO_4 CEM.

Division's Response: The Division concurs and has amended the permit.

37. Section B, 6. g.; page 28 – Delete reference to H_2SO_4 CEM.

Division's Response: The Division concurs and has amended the permit.

38. Section B (EU08), Section Title; page 29 – Only one unit, delete "s" in Group title.

Division's Response: The Division concurs and has amended the permit.

39. Section B, 3. a.; page 33 – Add alternate H_2SO_4 test method to list of test methods.

Division's Response: The Division concurs and has amended the permit.

40. Section B (EU10), Description; page 41 – Optimal design for emergency stack lids may not be "clamshell" arrangement. Change words "...clamshell lids…" to "...stack lids…"

Division's Response: The Division concurs and has amended the permit.

41. Section B, 2. (b); page 45, and Section B, 4.; page 45 – Add "/spargers" to each reference to natural gas lances to make description consistent

Division's Response: The Division concurs and has amended the permit.

42. Section B, 6. b.; page 55 – Design changes may go through several iterations and it may not be possible to provide the final version of a change within 30 days after the design is changed. Request that the "30 days" be changed to "a reasonable time".

Division's Response: See Division's response to comment 26, above.

43. Section B, 6. a.; page 61 – Design changes may go through several iterations and it may not be possible to provide the final version of a change within 30 days after the design is changed. Request that the "30 days" be changed to "a reasonable time".

Division's Response: See Division's response to comment 26, above.

44. Section B, 2.b.; page 64- Specific Monitoring Requirements list qualitative visible emission. Observation followed by Method 9 if needed. Revise for consistency.

Division's Response: The Division concurs and has amended the permit.

45. Section B, 6. a.; page 65 – Design changes may go through several iterations and it may not be possible to provide the final version of a change within 30 days after the design is changed. Request that the "30 days" be changed to "a reasonable time".

Division's Response: See Division's response to comment 26, above.

46. Section B; page 66- HRGS's are not emission units. Move to subsection.

<u>Division's Response</u>: The Division does not concur. Although not emissions units, as is discussed in the description section for the units, the HRSG's have a unique non-applicable regulation and compliance requirement to ensure non-applicability (i.e. Acid Rain Program). The units have been given a separate section for ease of compliance demonstration and inspection.

47. Section B (EU23) Description; page 66- Clarify threshold for HRSG is less than or equal to 25MW for each HRSG.

<u>Division's Response</u>: The Division concurs and has amended the permit and Statement of Basis.

48. Section B; page 66. Revise wording to match CFR.

<u>Division's Response</u>: The Division concurs and has amended the permit.

49. & 50. Section B; page 66. Simplify monitoring if the HRSGs are identical.

<u>Division's Response</u>: The Division does not concur. Each HRSG must be evaluated separately for compliance with the Acid Rain Program.

51. Page 68, Emergency Engine A (EU24), Description – The Planned Model Year of the engine should be changed from 2014 to 2013.

<u>Division's Response</u>: The Division concurs and has amended the permit to allow for later models.

52. Page 73, Emergency Engine A (EU24), 6.b. – The requirement to notify the Division of engine specifications should be removed.

<u>Division's Response</u>: The Division does not concur. The Division requires information on this contaminant source sufficient to ensure that emissions are accurately calculated and that the unit as described (HP rating, displacement, etc.) is properly regulated. The complexity of the subparts addressing reciprocating internal combustion engines requires precise specifications to assess regulatory applicability.

53. Page 74, Emergency Generator B (EU25), Description – The phrase, "of the coke screening equipment" should be changed to, "in the screening station area."

<u>Division's Response</u>: The Division concurs and has amended the permit.

54. Page 74, Emergency Generator B (EU25), Description – The Planned Model Year of the engine should be changed from 2014 to 2013.

<u>Division's Response</u>: The Division concurs and has amended the permit to allow for later models.

55. Page 74, Emergency Generator B (EU25), 1.b. – The indicated reference in 40 CFR 60.4211(c) should be changed from 40 CFR 60.4204(b) to 40 CFR 60.4202(a) to reference standards for emergency engines.

<u>Division's Response</u>: The Division partially concurs. The Division has changed the reference from 40 CFR 60.4204(b) to 40 CFR 60.4205(b) in order to be consistent with 40 CFR 60.4211(c). The commenter is correct that the standards for emergency engines are contained in 40 CFR 60.4202(a), however, the cited regulation refers emergency engines to 40 CFR 60.4205(b), which subsequently refers to 40 CFR 60.4202.

56. Page 80, Emergency Generators C and D (EU26, EU27), 6.d. – The requirement to notify the Division of engine specifications should be removed.

<u>Division's Response</u>: See Comment #52.

57. Page 81, Emergency Generator C (EU26), Description – The Planned Model Year of the engine should be changed from 2013 to 2014.

<u>Division's Response</u>: The Division concurs and has amended the permit to allow for later models.

58. Page 81, Emergency Generator D (EU27), Description – The Planned Model Year of the engine should be changed from 2013 to 2014.

<u>Division's Response</u>: The Division concurs and has amended the permit to allow for later models.

59. Page 82, Emergency Generators C and D (EU26, EU27), 1.b. – The indicated reference in 40 CFR 60.4211(c) should be changed from 40 CFR 60.4204(b) to 40 CFR 60.4202(a) to reference standards for emergency engines.

<u>Division's Response</u>: The Division does not concur. The language matches that of 40 CFR 60.4211(c). The Division has clarified the requirement by removing references applicable to non-emergency engines only.

60. Page 88, Crane E (EU28), Description – The Planned Model Year of the engine should be changed from 2014 to 2013.

<u>Division's Response</u>: The Division concurs and has amended the permit to allow for later models.

61. Page 88, Crane F (EU29), Description – The Planned Model Year of the engine should be changed from 2014 to 2013.

<u>Division's Response</u>: The Division concurs and has amended the permit to allow for later models.

62. Page 89, Cranes E and F (EU28, EU29), 1.b. – The indicated reference in 40 CFR 60.4211(c) should be changed from 40 CFR 60.4205(b) to 40 CFR 60.4201 to reference standards for non-emergency engines.

<u>Division's Response</u>: The Division partially concurs. The indicated reference has been corrected to 40 CFR 60.4204(b). See Comment #52.

63. Page 91, Cranes E and F (EU28, EU29), 2.c. – The carbon dioxide emission limitation should show one additional significant digit (5,400 TPY – 5,430 TPY).

<u>Division's Response</u>: The Division concurs and has amended the permit.

64. Page 92, Cranes E and F (EU28, EU29), 3.e. – The phrase, "unless otherwise specified" should be added to be consistent with citation.

<u>Division's Response</u>: The Division concurs and has amended the permit.

65. Page 92, Cranes E and F (EU28, EU29), 3.f. – The phrase, "if this option is selected" should be added to clarify that there are other compliance options.

<u>Division's Response</u>: The Division concurs and has amended the permit.

66. Page 93, Cranes E and F (EU28, EU29), 3.k. – The phrase, "and not using a CEMs" should be added to clarify that there are other compliance options.

<u>Division's Response</u>: The Division does not concur. This exemption is already incorporated into Table 3 to 40 CFR 63 Subpart ZZZZ.

67. Page 95, Cranes E and F (EU28, EU29), 4.f.(1) – The phrase, "required performance evaluations" should be added to be consistent with the citation.

<u>Division's Response</u>: The Division concurs and has amended the permit.

68. Page 98, Cranes E and F (EU28, EU29), 6.j.(4) – This condition should be changed to the requirement of 40 CFR 63.6650(c)(4).

<u>Division's Response</u>: The Division concurs and has amended the permit.

69. Section D, 1.,d page 120 ; Clarify that the facility may choose between the two compliance methods in the section.

<u>Division's Response</u>: The Division concurs and has amended the permit.
70. Section D, 5.f.; page 130; Revise CFR Citation

Division's Response: The Division concurs and has amended the permit.

71. Section D, 5.g.; page 130; Revise CFR Citation

Division's Response: The Division concurs and has amended the permit.

Commonwealth of Kentucky
Division for Air Quality

COMMENTS AND RESPONSES

ON THE DRAFT PERMIT

Comments on SunCoke Energy South Shore, Inc. Draft Title V/Title 1 PSD Construction/Operating Air Quality Permit submitted by R. Scott Davis, Chief, Air Planning Branch of the United States Environmental Protection Agency

See Attachment #3 below for Comments #1-3 by EPA on Draft Title V Permit
See Attachment #4 below for SESS Response to EPA Comments on Draft Title V Permit

1. *In response to the EPA's comment concerning the evaluation of lower sulfur coal, comments in our June 27, 2013, letter, the applicant provided several technical reasons as well as a brief discussion of the economic impacts associated with using a lower sulfur coal (1.1% sulfur content) beyond during the startup process to reduce SO_2 and H_2SO_4 emissions from the proposed facility. The EPA suggests that the SOB be revised to include a summary of this information provided by the applicant in their July 19, 2013, letter to Kentucky.*

Division's Response: The Division concurs and has amended the Statement of Basis by adding additional information provided by Sun Coke Energy South Shore summarizing the basis for the exclusion of coal less than 1.3 percent sulfur as BACT. The summary added to the Statement of Basis is as follows:

> Use of coal with a lower sulfur content than 1.3 percent was not evaluated because lower sulfur coal may not be available in the quantities required. Using coal containing as much as 1.3 percent sulfur will be necessary to supply sufficient amounts for continuous operation. The availability and quality of metallurgical coals has been subject to a number of trends and events that make the prediction and control of coal sulfur content challenging, both in the long term and the short term.
>
> First, the supply of coal suitable for metallurgical applications (i.e. high BTU content, high volatilization, and low sulfur) in the United States has exhibited significant volatility in the last few years. Availability of this type of coal has been impacted by several force majeure events at major U.S. metallurgical coal mines. During these events, the limited availability of alternative supplies has generally led to higher sulfur contents for replacement coals. Market factors have also affected the availability and quality of metallurgical coals available for purchase. With the sustained market downturn and the resultant low price of metallurgical coals, an increasing number of mines have idled.
>
> Second, the sulfur of available coals has trended up over the past decade with higher sulfur metallurgical coals in the >1.5 percent sulfur content range currently on the market. The coal quality of existing U.S. metallurgical mines, especially with regard to sulfur, has exhibited a deteriorating trend as reserves deplete. Because of this overall

market drift toward higher sulfur coal, any permit limitations regarding sulfur must reflect the market statics and future availability.

2. *In the EPA's comment letter (June 27, 2013), we provided a comment regarding the setting of GHG best available control technology (BACT) limits for all emissions units, preferably on an output basis, According to the applicant's response document (page 4) from July 19, 2013, while they have been gathering CO2 emissions data from the heat recovery coke-making process for 2 years, they still do not have sufficient data to establish output based limits (e.g., lb CO2/ton coke). The applicant did propose and Kentucky established tpy BACT limits on most processes emitting GHGs. It is the EPA's understanding that the vast majority (1,301,000 tpy CO2e) of GHG emissions come from the heat recovery coke ovens and are emitted through the main coking stack. The EPA still believes output-based limits are the most appropriate format for GHG BACT limits when relying on energy efficiency (e.g., heat recovery and combustion optimization) for GHG control. However, in lieu of output-based GHG BACT limits, the EPA suggests additional monitoring and periodic stack testing and/or continuous emission monitoring of CO_2 emissions to ensure the tpy BACT limits are practically enforceable. Furthermore, this enhanced monitoring would provide additional information about the GHG emissions from the coke-making process to supplement the information the applicant has already been gathering.*

Division's Response: The Division concurs and has amended both the Statement of Basis and the permit to incorporate performance testing according to EPA Reference Method 3A for CO_2, an additional test during the permit term to ensure continuous compliance, and monitoring through monthly calculations of the CO_2 emissions from the main stack.

3. *According to the SOB (Table 6), Kentucky declared the PSD application complete on August 8, 2013. The EPA received an email from KDAQ on August 12, 2013, which included all of the supporting documents received at that time. However, the SOB indicates there have been many additional modeling files and other items related to the Air Quality analysis, which were dated after August 12, 2013. To date, these additional files have not been provided to the EPA. Consequently, the EPA can neither review/evaluate the Air Quality analysis performed by the applicant, nor evaluate the information and analyses presented in the Kentucky SOB. In order for the EPA to fulfill its oversight responsibility of the PSD program, all information (including that received after the application completeness determination date) that was used by Kentucky to make a determination regarding this project's compliance with the PSD program should have been provided to the EPA.*

Division's Response: The Division does not concur. The Division complied with all public participation requirements pursuant to 401 KAR 51:017 and 401 KAR 52:020, including the applicable procedures of 40 CFR 51.166(q) and 401 KAR 52:100. As the commenter states, "The EPA received an email from KDAQ on August 12, 2013, which included all of the supporting documents received at that time." The Division determined the application complete at that time.

Furthermore, the Division provided EPA with the public notice of availability on December 22, 2013, in accordance with all applicable requirements under the Clean Air Act, specifically the requirements of 40 CFR 51.166(q)(2)(iv).

> *Additional Comment: Finally, the EPA notes that the SOB is dated November 27, 2013; however, according to the SunCoke Modeling Application Timeline (Table 6), the last document received by Kentucky is dated December 16, 2013. The EPA suggests the date on the SOB is revised to reflect this most recent information referenced in the SOB to avoid confusion for the public.*

Division's Response: The Division concurs as the final amendment to the Statement of Basis for the draft permit occurred on December 19, 2013. The Statement of Basis will be revised and the modified date of the Proposed Statement of Basis will be incorporated.

Commonwealth of Kentucky
Division for Air Quality

COMMENTS AND RESPONSES

ON THE DRAFT PERMIT

Comments on SunCoke Energy South Shore, Inc. Draft Title V/Title 1 PSD Construction/Operating Air Quality Permit submitted by Laurie Williams, Associate Attorney, Sierra Club

See Attachment #5 below for Sierra Club comments on Draft Title V Permit
See Attachment #6 below for SESS Response to Sierra Club comments on Draft Title V Permit

I. DAQ Cannot Issue a Permit for the SunCoke Plant Because the Plant Will Contribute to Multiple NAAQS Violations.

The Clean Air Act and DAQ regulations prohibit the construction of a new source unless the owner/operator of the facility demonstrates that emissions from construction or operation of the facility will not cause or contribute to "air pollution in excess of any. . . national ambient air quality standard in any air quality control region." 42 U.S.C. § 7475(a)(3); see also 401 KAR 51:017 Section 9; 40 C.F.R. 51.166(k).

During the application phase, the applicant must demonstrate that:

allowable emission increases from the proposed major source or major modification, in conjunction with all other applicable emissions increases or reduction, including secondary emissions, shall not cause or contribute to air pollution in violation of either of the following:

(1) Any national ambient air quality standard in any air quality control region.
(2) Any applicable maximum allowable increase over the baseline concentration in any area.[1]

In keeping with this requirement, the Clean Air Act requires a permit applicant to "conduct such monitoring as may be necessary to determine the effect which emissions from any such facility may have, or is having, on air quality in any area which may be affected by emissions from such source." 42 U.S.C. § 7475(a)(7). More specifically, at a minimum, the full PSD review must "be preceded by an analysis… by the State… or by the major emitting facility applying for such permit, of the ambient air quality at the proposed site and in areas which may be affected…" 42 U.S.C. § 7475(e)(1). This "preconstruction" analysis "shall include continuous air quality monitoring data gathered for purposes of determining whether emissions from such facility will exceed the [NAAQS or PSD increment]." 42 U.S.C. § 7475(e)(2) (emphasis added). Federal and state regulations similarly require the applicant to submit a pre-application analysis of ambient air quality in affected areas that includes at least one year of representative continuous air quality monitoring data. See 40 C.F.R. § 51.166(m)(1)(iv).

The Draft Permit fails by its own terms to comply with the sections of the Clean Air Act and Kentucky regulations excerpted above. Table 9 in the Permit's Statement of Basis shows that there are significant NAAQS violations in the area where the SunCoke Plant is to be constructed.[2] *The 1-hour SO2 NAAQS for the area is 196.5 $\mu g/m^3$.*[3] *The modeled 1-hour SO2 concentration*

> ***without*** *the SunCoke Plant is 1333.0 µg/m^3, which is above the NAAQS threshold by nearly seven fold.*[4] *If the SunCoke Plant is built, the modeled concentration will rise to 1393.11 µg/m^3.*[5] *The Clean Air Act and Federal and state regulations are unambiguous that Title V permits cannot be issued in such circumstances. 42 U.S.C. § 7475(a)(3); 401 KAR 51:017 § 9(1). The Division cannot issue a construction permit when its own modeling data shows that there are NAAQS violations in the area where the proposed facility would be constructed.*
>
> *The 1-hour SO2 standard is not the only NAAQS for which there are modeled violations demonstrated in the Draft Permit's Statement of Basis. Table 9 in the Statement of Basis also shows violations of the 24-hour PM10 NAAQS and the 24-hour PM2.5 NAAQS. The 24-hour PM10 NAAQS for the area is 150 µg/m^3.*[6] *The modeled 24-hour PM10 concentration without the SunCoke Plant is 256.3 µg/m^3 and will rise to 291.3 µg/m^3 if the SunCoke Plant is constructed.*[7] *The 24-hour PM2.5 NAAQS for the area is 35 µg/m^3.*[8] *The modeled 24-hour PM2.5 concentration without the SunCoke Plant is 129.2 µg/m^3 and will rise to 148.5 µg/m^3 if the SunCoke Plant is constructed.*[9] *Again, for the Division to issue a construction permit for the SunCoke Plant when its modeling data shows that there are NAAQS violations to which the SunCoke Plant would contribute would constitute a blatant violation of the plain language of the CAA and Kentucky regulations.*

Division's Response: The Division does not concur. In response to the comment on preconstruction monitoring:

40 CFR Part 51 Appendix W, Section 8.2.2 allows for the use of "air quality data collected in the vicinity of the source to determine the background concentration for the averaging times of concern." In addition, a regional monitor may be used if "there are no monitors located in the vicinity of the source, a 'regional site' may be used to determine background. A 'regional site' is one that is located away from the area of interest but is impacted by similar natural and distant man-made sources." In accordance with Appendix A to 40 CFR Part 58, the ambient air monitoring data collected by the Ohio Division of Air Pollution Control for PM_{10} and SO_2 at the New Boston, Ohio station meets the quality assurance requirements and 'regional site' qualifications for PSD air monitoring. Thus, preconstruction monitoring performed by the SunCoke facility was waived in favor of the existing monitor in the vicinity of the source.

In response to the NAAQS comment:

The Division does not concur. It appears that Sierra Club has misinterpreted Table 9 of the Statement of Basis. For instance, the *Modeled Concentration* column of the table refers to the concentration derived from the modeling demonstrations that were based on emissions from the off-site inventory and the SunCoke project, not the just the off-site inventory as indicated by the Sierra Club. For the 1-hour SO_2 standard, the modeled concentration of the off-site inventory and the SunCoke project is 1333.0 µg/m^3. These modeled concentrations are based on maximum allowable emission limits or federally enforceable permit limits and conservative modeling parameters, both of which do not reflect actual operating conditions. The 1-hour SO_2 background concentration from the New Boston, Ohio monitor of 60.11 µg/m^3 was added to the modeled concentration of 1333.0 µg/m^3 to derive the cumulative concentration of 1393.11 µg/m^3, which was then compared to the NAAQS. A culpability analysis was performed when the cumulative modeled impact results indicated a NAAQS exceedance. The culpability analysis found in the application derived SunCoke project's level of contribution (as a concentration) to the modeled NAAQS exceedance (at the time and place of the exceedance). As stated in section VI of the preamble to Appendix W to 40 CFR Part 51:

> Where dispersion modeling predicts a violation of a NAAQS or PSD increment within the impact area but it is determined that the proposed source will not have a significant impact (i.e., will not be above de minimis levels) at the point and time of the modeled violation, then the permit may be issued immediately. . . .

The culpability analysis demonstrated that the SunCoke will not cause or significantly contribute to an exceedance of the NAAQS as indicated in Table 9 and is not contributing 60.11 $\mu g/m^3$ to a NAAQS violation as implied by Sierra Club. The table clearly indicates that the SunCoke project does not contribute significantly to any NAAQS exceedances. The same reasoning is applicable to the 24-hour PM_{10} NAAQS and the 24-hour $PM_{2.5}$ NAAQS. In sum, although modeled NAAQS exceedances do exist, SunCoke has demonstrated that they will not cause or significantly contribute to any exceedance of the NAAQS.

The Division has modified Section 6 *Class II Modeling Analysis* narrative and Tables 7, 8, and 9 in the Statement of Basis for clarification purposes.

II. The Emission Limits in the Draft Permit Fail to Satisfy the BACT Requirements of the Clean Air Act.

i. The 5-Step, Top-Down BACT Determination Process Applies.

> *It is undisputed that the Plant is subject to Best Available Control Technology (BACT) requirements for a number of air pollutants. BACT determinations require a thorough analysis of emission control technologies and involve a well-settled method of evaluation. The Draft Permit fails in multiple respects to satisfy the Clean Air Act's BACT requirements.*

A. BACT Requires Identifying the Maximum Emissions Reductions Achievable and Does Not Hinge Solely on Previous BACT Determinations Made for Other Facilities.

> *The Clean Air Act defines BACT as:*
>
> *An emission limitation based on the maximum degree of reduction of each pollutant subject to regulation… emitted 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 the 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 pollutant.*
>
> *By using the terms "maximum" and "achievable" in the definition of BACT, the Clean Air Act sets forth a "strong, normative" requirement that "constrain[s]" agency discretion in determining BACT. Alaska Dep't of Envtl Conservation v. EPA, 540 U.S. 461, 485-86 (2004). 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 to specific collateral impact concerns. Alaska Dep't of Envtl. Conserv. v. EPA, 298 F.3d 814, 822 (9th Cir. 2002). 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 (E.A.B. Sept. 27, 2006).*
>
> *BACT's focus on the maximum emission reduction achievable makes the standard both*

> *technology-driven and technology-forcing. 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, with standards set accordingly. For instance, technology transfer from other sources with similar exhaust gas conditions must be considered explicitly in making BACT determinations.*
>
> *Notwithstanding its statutory mandate to choose the maximum achievable degree of emission reductions when setting BACT, DAQ proposed BACT limits that it touted as being "comparable" to previous set BACT limits. It appears that DAQ's BACT analysis began and ended with review of the RACT/BACT/LAER Clearinghouse (RBLC) database. Statements such as "this system is not listed as having been successfully demonstrated in any RBLC determination and is not considered a feasible option for SESS" appear throughout the Statement of Basis and reveal a fundamentally flawed BACT determination process. As described in the preceding paragraph, the universe of sources that one must consider in making a BACT determination is much broader than just recently permitted sources. Other information sources must be considered to assure that the lowest achievable emission limit is specified as BACT. These other sources include control technology vendors, technical literature, and foreign experience. Moreover, even if it were legally sufficient to look only at recent BACT determinations set for other facilities, the emissions reductions set in the Draft Permit are still inadequate. The NUCOR permit referenced in the Statement of Basis set enforceable limitations of 0.071 lbs/ton NOx and 0.035 lb/ton VOC. In contrast, the Draft Permit's BACT limits are 1.0 lb/ton NOx and 0.04 lbs/ton VOC. DAQ can only implement BACT limits less stringent than the maximum achievable if it can show compelling, facility-specific collateral impacts, which DAQ does not do here. DAQ clearly employed a fundamentally flawed process in making its BACT determinations which resulted in emissions limits that are much weaker than the maximum achievable standards. The Draft Permit cannot be issued until DAQ corrects these critical errors in its BACT determinations and re-circulates a revised permit for public review.*

Division's Response: The Division does not concur that BACT limits have been improperly established or that the analysis has been improper for this facility.

As documented in the Statement of Basis and numerous documents included in the public record, SESS followed the 5-step, Top-down BACT process, evaluating technologies currently in use as well as those under development and considering all costs (monetary and otherwise) associated with the technologies as documented in Section 5 of the application. The Division independently researched the determinations and imposed the most stringent permit limits in accordance with BACT requirements as defined in 401 KAR 51:001(25).

The comments characterizing the DAQ evaluation as referencing only the RACT/BACT/LAER clearinghouse are inaccurate. The RACT/BACT/LAER clearinghouse was referenced, and utilized as a resource to ensure that no permitted project was omitted from review. DAQ consulted numerous informational sources, including publications, research documents, experts in various fields in both the U.S. and abroad, industrial literature, etc. during the course of the analysis of this application. A partial bibliography of the more important information accessed is included as Attachment #7 to this document.

SESS has its own responses to these Sierra Club comments. See Attachment # 6.

B. DAQ's BACT Analysis Failed to Follow the 5-Step, Top-Down Process that Kentucky Adheres to in its BACT Determinations.

Kentucky law contains a definition of BACT that is similar to the Clean Air Act's definition. 401 KAR 51:001, § 1(25). Under both definitions, BACT requires a forward-looking analysis of what the facility can achieve in the future, based on what is presently known about the effectiveness of the best pollution control options. Newmont Nevada Energy Investments, LLC, TS Power Plant, PSD Appeal No. 05-04, Slip Opinion at 16 (EAB Dec. 21, 2005).

EPA regulations require the Division, as the PSD permitting authority, to perform and document an analysis to ensure that BACT limits are at least as stringent as federal BACT. 42 U.S.C. § 7475(a)(4); 40 C.F.R. § 52.21(j). To implement BACT permitting, EPA established a "top-down BACT analysis" process, which it outlined in its New Source Review Workshop Manual (Draft October 1990) ("NSR Manual"). EPA's Environmental Appeals Board has adopted the use of the NSR Manual as controlling authority when deciding cases. See In re Masonite Corp., 5 E.A.D. 558 (EAB 1994); Inter-Power of New York, Inc., 5 E.A.D. 135 (EAB 1994). The Division implements PSD permitting in Kentucky by applying the NSR Manual's process as the appropriate analysis for new source review determinations. The Environmental Appeals Board has held that, when a state permitting agency attaches importance to the NSR Manual, the Manual then serves as "an important reference point in assessing whether [the agency] has acted rationally in the context of a given permit." In re General Motors, Inc., 10 E.A.D. 360, 366 (EAB 2002) (discussing Michigan's reliance on the NSR Manual). The top-down BACT analysis consists of five steps:

1. *Identify all control technologies (including lowest achievable emission rate or LAER).*
2. *Eliminate technically infeasible options.*
3. *Rank the remaining control technologies by control effectiveness.*
4. *Evaluate the most effective control and document results.*
5. *Select BACT.*

NSR Manual at Table B-1. The first step of this process requires all available control technologies to be identified before any are rejected as technically infeasible or due to cost or other factors. After all available control technologies are identified, the most stringent or top alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify the rejection of the top alternative. NSR Manual at B.2. If the top alternative is rejected, the next most stringent option is selected as BACT unless the applicant demonstrates, similar to the top alternative, that technical, environmental, or economic considerations justify the rejection of the second option. NSR Manual at B.2.

Although the focus of a BACT analysis is mainly on the control technology or pollution prevention practices applicable to an applicant source, BACT actually refers to the numeric emission limit (i.e., pounds per Million Btu heat input) that corresponds with a specific, "best," control option (e.g., a selective catalytic reduction system). In re Three Mountain Power, LLC, 10 E.A.D. 31, 54 (EAB 2001). Therefore, DAQ must determine the top pollutant control option and set the corresponding limit based on the maximum pollution reduction achievable by that control technology. BACT is an emission limit "based on the maximum degree of reduction... that is achievable…" 42 U.S.C. § 7479(3). In other words, even after selecting the top control technology, the Division must also ensure that the BACT emission limit is the lowest achievable emission rate for each pollutant based on the control potential of the top technology. The NSR

Manual clearly requires the lowest possible emission rate to be selected as the BACT limit. NSR Manual at B.29. If the lowest emission rate is not set as BACT, "the rationale for this finding needs to be fully documented for the public record." NSR Manual at B.29. U.S. EPA has continuously stressed the importance of a rigorous BACT analysis process and complete record supporting the permitting agency's determinations:

The BACT analysis is one of the most critical elements of the PSD permitting process. As such, it should be well documented in the administrative record. A permitting authority's decision to eliminate potential control options as a matter of technical infeasibility, or due to collateral impacts, must be adequately explained and justified.

Therefore, when establishing a BACT limit, DAQ must identify the most effective pollution control option, and must set BACT based on that option unless the applicant can demonstrate that the most effective pollution control option must be rejected based on energy, environmental, or economic impacts- which are unique to the specific facility. As EPA has repeatedly stated, the collateral "energy, environmental, or economic impacts" exception ("collateral impacts" exception) to the top-control option is narrow, to be used sparingly on unique circumstances at the source. NSR Manual at B.29.

The [collateral impacts] clause [of the BACT definition] allows rejection of the most effective technology as BACT only in limited circumstances. The collateral impacts clause operates primarily as a safety valve whenever unusual circumstances specific to the facility make is appropriate to use less than the most effective technology.

In re Kawaihae Cogeneration Project, 7 E.A.D. 107, 116-17 (EAB 1997) (emphasis original); see also In re World Color Press, Inc., 3 E.A.D. 474, 478 (Adm'r 1990) (collateral impacts clause focuses on the specific local impacts).

Division's Response: The Division disagrees that it has not implemented the technology-forcing BACT requirement properly for this facility. As documented in the DAQ's Statement of Basis, and other supporting documents, the DAQ reviewed the 5-step, Top-Down BACT analysis submitted in the SESS application, and independently reviewed technologies that are currently in use and technologies that are being newly developed. Based on these analyses, the DAQ imposed the most stringent permit limits achievable in accordance with the BACT requirements. See response to comment A, above.

ii. DAQ Improperly Applied the 5-Step BACT Determination Process and Eliminated Control Technologies for Invalid Reasons.

The Division failed in a number of respects to adequately perform the top-down BACT analysis, rendering the draft permit inadequate. In determining BACT for SO2, the Division eliminated a potential control technology – a wet scrubber – based exclusively upon consideration of incremental cost.20 As the EAB held in General Motors, however, permitting agencies cannot rely exclusively on incremental cost as the sole measure of a control technology's economic feasibility.[21] *They must also consider the control option annual cost, which is calculated differently from the incremental cost.*[22] *As the EAB in General Motors reasoned: "undue focus on incremental cost-effectiveness can give an impression that the cost of a control alternative is unreasonably high, when, in fact, the cost effectiveness, in terms of dollars per total ton removed, is well within the normal range of acceptable BACT costs."*[23] *This is precisely the case with the SunCoke facility, as the control option annualized cost of a wet scrubber is $2141/ton SO2, which is comparable to other BACT costs.*[24] *Moreover, even if incremental cost were the sole measure* *of economic feasibility, the Division's SO2 BACT analysis would still be improper because the Division did not indicate the unusual, facility-specific circumstances that would make it appropriate to reject the wet scrubber on the basis of collateral impacts.*[25]

Likewise, in determining BACT for NOx, the Division performed an inadequate analysis of control technology feasibility. It is the Division's duty to "adequately explain and justify" any decisions to eliminate potential control options for reasons of technical infeasibility.[26] *An adequate explanation requires, among other things, documented evidence.*[27] *Yet the Division's justification for eliminating both SNCR and HSSCR consisted of just a few unsupported sentences:*

> *As with the SNCR, there is the potential for ammonia slip and the resultant formation of ABS. This sticky substance would foul the downstream HRSGs and is difficult to control. This would increase the maintenance required and the cost. The HSSCR is therefore considered infeasible for use with the SESS facility.*[28]

This falls well short of the adequate, documented explanation required by law.[29] *Moreover, the Division impermissibly cited increased maintenance as the dispositive concern in this perfunctory analysis. Even if the SunCoke facility must redesign certain equipment in order to handle a SNCR or HSSCR, that would not render these controls technically infeasible. NSR Manual at B.20 ("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."). Fouling and ammonia slip are common design factors in all SNCRs.*[30] *The Draft Permit cites no unique characteristics in the Suncoke design that are not present in other sites which use SNCRs to control NOx emissions. Because SNCR and HSSCR cannot be excluded as technically infeasible, the Division must perform cost analysis for these technologies.*
Beyond the SNCR and HSSCR, the Division eliminated several additional NOx control devices for impermissible reasons.[31] *The Division excluded control strategies because the "technology requires a wastewater treatment plant," or "[the technology] has only been demonstrated with small to medium-sized boilers."*[32] *Neither of these reasons provides an adequate justification for rejecting control technologies. As described above in the context of the SNCR and HSSCR, the fact that a control technology might require design alterations does not mean that the technology is infeasible. Moreover, these technologies have been widely used during the combustion of coal.*[33] *Partial combustion of the same coal does not present unique technical challenges that are grounds for excluding these technologies.*

24 See generally U.S. EPA, Emission Control Technologies, available at http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter5.pdf. 25 See In re Kawaihae Cogeneration Project, 7 E.A.D. 107, 116-17.
26 NSR Manual at B.26-B.29; Knauf, 8 E.A.D. at 131. ("A permitting authority's decision to eliminate potential control options as a matter of technical infeasibility, or due to collateral impacts, must be adequately explained and justified.").
27 Id.
28 See Statement of Basis, at 35.
29 See NSR Manual at B.26-B.29; Knauf, 8 E.A.D. at 131
30 See generally U.S. EPA, NOx Controls, 1-7, available at http://www.epa.gov/ttn/catc/dir1/cs4-2ch1.pdf.
31 See Statement of Basis, at 56.
32 Id.

Division's Response: The Division does not concur. The Statement of Basis and supporting documents in the public record, clearly demonstrate that the Division has reviewed the SESS application, which applies the five-step approach, and selected BACT in accordance with the BACT definition of 401 KAR 51:001.

In the comment, it is asserted that the analyses are inadequate and yet many of the perceived omissions discussed in the comments have actually been addressed as evidenced by the public record.

For example, the comment characterizes the analysis of the wet scrubber technology as inadequate and claims that the control was rejected based solely upon the incremental cost. The complete impacts of the use of this technology, including effect on the environment, energy use, costs, and other were examined when considering the use of this technology. This analysis is evidenced in the public record. Only a brief paragraph outlining these considerations and the monetary cost analysis were included in the SOB for the sake of brevity. More details, including a top-down analysis for SO_2 control, and a complete cost analysis for the wet scrubber system are included in the application that has been reviewed and accepted by the Division (See section 5.4.1.3 and Appendix G).

In another example, the comment calls the analysis of the use of SNCR 'perfunctory' and states the justification consists of "just a few unsupported sentences". Again, the information that supports the decision to reject the technology is included in the public record in the application and follow-up correspondence. The comment goes on to claim that the reasons cited for elimination are actually common, but the unique fouling due to the non-recovery process is discussed throughout section 5.6 of the application. The combustion of flue gasses is not the same as the combustion of coal. Additional difficulties occur during this process that cannot be remedied by standard procedure used for coal combustion. Coal is not combusted in the coking process, but volatile gases are produced that can be burned. Combusting these coking gases (flue gas) contains less particulate than combusting coal, because no ash is produced as most of the carbon is retained in the coke. Fly ash produced in coal combustion is alkaline and will absorb acidic HCl in the gas stream. Since fly ash is not present in flue gas combustion, sticky chloride salts form. Standard coal boiler blow-down procedures and even percussive charges do not remove the sticky substance in the downstream equipment of coke ovens and fouling occurs. Additionally, the process-specific temperature ranges involved eliminate other controls from consideration, and the process-specific NOx levels are low enough that control equipment efficiencies are very low, rendering the control ineffective and not justifiable because of costs.

In order to provide a succinct, but thorough and accessible review of the BACT conclusions for this project, the Division outlined the issues, analysis, and reasoning behind its decisions in the Statement of Basis for the SESS draft permit. Additional information, including complete cost analyses, discussions of alternate technologies, discussions of possible alternate operating scenarios, etc., are included in the public record in both the application and correspondence between the source and the Division. To include the entirety of the public record in the Statement of Basis would be redundant and expand the basis document to hundreds of pages, rendering it unreadable and unusable for the general public.

The Division believes that the documents referenced in the application and correspondence in the public record provides ample explanation and background for the decisions made regarding BACT for this facility and satisfies the requirement that a BACT analysis "should be well documented in the administrative record" (In RE Knauf Fiber Glass, GMBH at 131).

However, in order to further demonstrate the due diligence applied to this project, a bibliography of the more important articles and industry consultants with which the Division conferred during analysis of the application has been attached to this comments and responses document.

C. The Draft Permit Does Not Meet BACT Requirements for Startup and Shutdown Operations.

> *BACT emission limits must be met on a continual basis at all levels of operation. 401 KAR 51:001 Section 1 (25); 401 KAR 51:017 Section 8; 42 USC §§ 7475(a)(4) and 7479(3); 40 CFR §§ 51.166(b)(12) and (j)(2). Startups and shutdowns are part of normal operation and the emissions that occur during these periods must be included in the BACT analysis and limited in the permit. See, e.g., In re Tallmadge Generating Station, Order Denying Review in Part and*

Remanding in Part, PSD Appeal No. 02-12, slip op. (EAB May 21, 2003) ("BACT requirements cannot be waived or otherwise ignored during periods of startup and shutdown."); In re RockGen Energy Center, 8 E.A.D. 536, 553-55 (EAB 1999) (holding that PSD permits may not contain blanket exemptions allowing emissions in excess of BACT limits during startup and shutdown).[34] "EPA's long-held interpretation is that emission limitations in PSD permits apply at all times and may not be waived during periods of startup and shutdown." See, e.g., Tallmadge Energy Center [sic], slip op. at 24. In re Louisville Gas & Electric Co., Partial Order Responding to March 2, 2006 Petition, at 10 (Sept. 10, 2008). Exemption of a source "from any concentration limits during startup and shutdown," including short-term limits, is "potentially a…serious concern." See In re Indeck-Niles Energy Center, PSD Permit No. 364-00A; PSD Appeal No. 04-01, 2004 EPA App. LEXIS 36, n. 9 (EAB Sept. 30, 2004) (emphasis added).
For a permitting agency to properly exempt a facility from startup and shutdown emission limits, the agency must make on-the-record, pollutant-by-pollutant determinations as to whether "compliance with existing permit limitations is infeasible during startup and shutdown." In re RockGen Energy Center, PSD Appeal No. 99-1, 8 E.A.D. 536 at 553 (Aug. 25, 1999). These determinations must be thoroughly documented, and take into account the extent to which control equipment for the different pollutants will continue to function during startup, shutdown, and malfunction.[35] Unless DAQ justifies an exemption with this type of rigorous analysis, it must include emission limitations for periods of startup and shutdown in order to provide the "continuous" emissions limitations required by the Clean Air Act.[36] 401 KAR 51:001 Section 1 (25); 401 KAR 51:017 Section 8; 42 USC §§ 7475(a)(4) and 7479(3); 40 CFR §§ 51.166(b)(12) and (j)(2).

33 See generally U.S. EPA, Air Pollution Control Technology Fact Sheet, available at http://www.epa.gov/ttn/catc/dir1/fsncr.pdf.
34 See also Memorandum from John B. Rasnic, EPA Stationary Source Compliance Division, to Linda M. Murphy, EPA Region 1, Automatic or Blanket Exemptions for Excess Emissions During Startup, and Shutdowns Under PSD (January 28, 1993) ("Rasnic 1993 Memorandum"); 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"). We note that BACT covers periods of so-called malfunction to the extent that the malfunction could have been anticipated and avoided through proper maintenance. See id.
35 See, e.g., In re Indeck-Elwood LLC PSD Permit No. 197035AAJ Order Denying Review in Part and Remanding In Part, September 27, 2006 at p. 70.
36 See 78 Fed. Reg at 54,822, 54,825 ("The legal and factual basis supporting the concept of an affirmative defense for malfunctions does not support providing an affirmative defense for normal modes of operation like startup and shutdown.").

While the Draft Permit contains some record-keeping and monitoring requirements for periods of startup and shutdown,[37] it does not contain any emission limitations, in violation of the law. Most portions of the Permit simply fail to mention startup and shutdown periods, while at least one appears to exempt such periods from emission limitations without any justification. The Permit states "excluding the startup and shutdown periods, if any 3-hour average sulfur dioxide or sulfuric acid value exceeds the standard, the permittee shall . . . . [inspect and make repairs]."[38] Neither the Draft Permit nor the Statement of Basis provide any explanation for this apparent exemption, much less the thoroughly documented, pollutant-specific analysis which is required under Federal and state law. See RockGen Energy Center, at 553. There is no evidence that the Division considered ways to reduce or eliminate excess emissions during startup and shutdown, beyond the occasional mention of plans that are to be developed in the future, by the permittee.[39] To the extent that any startup and shutdown plans have been made, the crucial emissions elimination/reduction analysis has been delegated to the permittee, to be conducted at an undetermined future time, and will not be subject to a public approval process. This scheme is not acceptable under the CAA. Tallmadge, slip op at 26-27; RockGen, 8 E.A.D. 536, 551-555. The permit must describe the design, control, and methodological, or other changes that are appropriate for inclusion in the permit to minimize allowed excess emissions during startup and shutdown. Tallmadge, slip op. at 27. The Draft Permit must be revised and re-issued to establish

BACT limitations for startup and shutdown.

37 See, e.g., Draft Permit, at 25, 27, 98.
38 Draft Permit, at 25 (emphasis added). See also id. at 102 ("The emission limitations set forth in 40 CFR 63, Subpart L, shall apply at all times except during a period of startup, shutdown, or malfunction. The startup period shall be determined by the Administrator and shall not exceed 180 days." (emphasis added)).
39 See Draft Permit, at 107.
40 Cabinet Provisions and Procedures for Issuing Title V Permits, available at http://air.ky.gov/SiteCollectionDocuments/52-020%20IBR%20Final.pdf. (emphasis added). See also CAA § 504(a), 43 U.S.C. § 7661c(a) (requiring that every Title V permit "assure compliance by the source with all applicable requirements); 40 C.F.R. §70.1.
41 Draft Permit, at 5.
42 Id.

Division's Response: The Division does not concur. The permit does contain BACT requirements for start-up. BACT, as defined in 401 KAR 51:001, recommends implementation of work practice standards as an accepted method of minimizing emissions. The proposed SESS emission reduction strategy for start-up listed under operating limitations represents a more realistic and consistently achievable, yet still stringent, BACT limit. In accordance with 401 KAR 51:001, "The standard establishes the emissions reduction *achievable* by implementation of the *work practice*, or operation."

The permit contains work practice standards in lieu of numerical emission limitations for periods of start-up because it is a one-time, extraordinary event for which work practice standards and time limitations are the only feasible way of controlling emissions. The ovens, tunnels and headers are constructed of expandable refractory brick which must be "cured in place", or heated slowly and steadily to operating temperature in order to allow for proper expansion. The control equipment used to reduce the various pollutants emitted must also be heated up and brought on line, but cannot be safely operated until there is sufficient coke oven gas to sustain operation of the HRSGS and the circulating dry scrubber. Start-up must occur in a planned sequence and pieces of equipment cannot be independently started. Coke oven battery start-up occurs only once. Once started, shutting down the ovens can cause severe structural damage to the equipment; therefore start-up will not occur more than once for this facility.

Because the control equipment must be heated to operating temperature and seasoned (per manufacturer's requirements) before safe operation is possible, control is not immediately available during start-up. Therefore, work practices and time limitations are used to minimize all pollutants during the one-time, extraordinary event. The permit requires that coal charged to the ovens during start-up be kept at or below a maximum of 42.5 tons each, that the circulating dry scrubber and baghouse be brought online within 40 days after all ovens are initially charged, and that the facility use coal with a 1.1 percent sulfur content during start-up as opposed to the 1.3 percent sulfur limit in place during normal operations.

All of this information, including many additional details pertinent to start-up of the facility, is included in the public record. However, to provide additional clarity, the first sentence in the paragraph, above, has been added to the pertinent sections of the Statement of Basis.

The general description and considerations of start-up are included in the application, while the source response to the Notice of Deficiency, dated February 22, 2013, provides a very detailed description of the start-up of the facility and answers many questions posed by the Division regarding controlling and minimizing emissions during the start-up.

Per the definition of shutdown in 40 CFR 63.301, a shutdown cannot take place unless all of the ovens in a battery are without coal. This determination is also found in the memorandum from Kathleen M. Bennett, Assistant Administrator for Air, Noise, and Radiation, U.S. EPA, to Regional Administrators, Regions I-X (Feb. 15, 1983); and the memorandum from Kathleen M. Bennett, Assistant Administrator for Air, Noise, and Radiation, U.S. EPA, to Regional Administrators, Regions I-X (Sept. 28, 1982).

Furthermore, "The emissions during startup and shutdown need not to be treated as violations where the source adequately shows that the excess could not have been prevented through careful planning and design and that bypassing of control equipment was unavoidable to prevent loss of life, personal injury, or severe property damage." This determination is found in the memorandum from John B. Rasnic, Director, Stationary Source Compliance Division, Office of Air Quality Planning and Standards, U.S. EPA, to Linda M. Murphy, Director, Air, Pesticides and Toxics Management Division, U.S. EPA Region I (Jan. 28, 1993).

The DAQ does not concur with Sierra Club's characterization of this approach to minimizing emissions through work practice standards as exempting a facility from start-up and shutdown emission limits, therefore DAQ does not have cause to alter its BACT analysis. See definitions from 40 CFR 63.300, *National Emission Standards for Coke Oven Batteries*, below.

> *Shutdown* means the operation that commences when pushing has occurred on the first oven with the intent of pushing the coke out of all of the ovens in a coke oven battery without adding coal, and ends when all of the ovens of a coke oven battery are empty of coal or coke.
>
> *Start-up* means that operation that commences when the coal begins to be added to the first oven of a coke oven battery that either is being started for the first time or that is being restarted and ends when the doors have been adjusted for maximum leak reduction and the collecting main pressure control has been stabilized. Except for the first start-up of a coke oven battery, a start-up cannot occur unless a shutdown has occurred.

III. The Draft Permit Does Not Contain All Applicable Emission Limitations and Standards, as Required by Kentucky Regulations. (NOTE: To better address the following comments, the Division has divided section III into smaller sections and numbered them using the i, ii, iii, etc. notation.)

> *i. Another fundamental flaw with the Draft Permit is its failure to list all applicable emission limitations and standards. The Division's regulations for issuing Title V permits state: "permits shall contain emissions limitations and standards, including operational requirements and limitations that assure compliance with all applicable requirements at the time of permit issuance."[40] In contravention of this requirement, at multiple points the Draft Permit simply defers compliance demonstrations to a later, unspecified time. For example, the Draft Permit states that "compliance with 40 CFR 60.254(c), shall be demonstrated with submission to the Division of the required fugitive coal dust control plan before commencing start-up."[41] Similarly, the Permit says that compliance with 401 KAR 51:017 "shall be demonstrated by inclusion of proposed BACT controls in the fugitive coal dust control plan and compliance with 40 CFR 60.254."[42] These provisions would allow the Division to make BACT determinations outside of the permit process and without any opportunity for public or U.S. EPA review. A fugitive coal dust control plan must be made available prior to the issuance of a permit, or sufficient portions of that plan must be included in the Draft Permit to meet the regulatory requirement that "permits shall contain emission limitations and standards, including operational requirements and limitations that assure compliance with all applicable requirements at the time of permit issuance."[43]*

<u>Division's Response</u>: The Division does not concur. The portions of the fugitive dust control plan necessary to comply with the BACT determination for this unit are defined in the permit and are listed below from page 5 of the permit:

c. Pursuant to 401 KAR 51:017, for Group I equipment, for fugitive PM, the following BACT

control technologies shall be applied:
(1) Coal Unloading: Barge unloading, no controls
(2) Coal Piles: Radial stacker, wet material, wind screen and/or berm
(3) Coal Crushing: Enclosure, wet material
(4) Coal Handling:
  (i) Blended Crushed Coal Storage: Enclosed bins, wet material
  (ii) Coal Conveyors: Enclosure (except where prohibited due to moving equipment), wet material

Thus, the Draft Permit states exactly what is considered BACT for coal piles, and obligates the Plant to utilize those technologies. The fact that the fugitive coal dust control plan, which must include these technologies, is actually submitted at a later date does not mean that BACT has not been identified at the time of permit issuance. All applicable requirements are therefore present in the Permit at the time of permit issuance.

ii. In addition to impermissibly postponing compliance demonstrations, the Draft Permit also entirely omits multiple applicable regulations, including 401 KAR § 59:015. Section 59:015 applies to any indirect heat exchanger, which is defined as "a piece of equipment, apparatus, or contrivance used for the combustion of fuel in which the energy produced is transferred to its point of usage through a medium that does not come in contact with or add to the products of combustion."[44] The combustion of coke gas at the SunCoke Plant will produce energy which is transferred through to the HRSGs.[45] This apparatus qualifies as an indirect heat exchanger under the broad definition established by 401 KAR § 59:015. DAQ's failure to include § 59:015 in the Draft Permit is a violation of the Clean Air Act and Federal and Kentucky regulations.[46]

Division's Response: The Division does not concur. 401 KAR 59:015 is not applicable to the HRSGs because they do not meet the definition of an indirect heat exchanger.

> "Indirect heat exchanger" means a piece of equipment, apparatus, or contrivance used for the combustion of fuel in which the energy produced is transferred to its point of usage through a medium that does not come in contact with or add to the products of combustion.

The HRSGs do not meet the definition because they do not involve the combustion of fuel. Additionally, as defined by 401 KAR 59:015, "Fuel means natural gas, petroleum, coal, wood, or a form of solid, liquid, or gaseous fuel derived from these materials for the purpose of creating useful heat." In the case of a non-recovery coking facility, the coke oven gases are combusted to control organic emissions by burning the gas. The heat recovered by the HRSGs is waste heat generated during the control of organics.

iii. The Draft Permit also fails to include 40 CFR 60 Subpart Db or Subpart Dc, which implement performance standards for steam generating units. The Statement of Basis justifies excluding Subpart Db from the Permit on the basis of 1999 U.S. EPA Policy determination, which held that, generally, Subpart Db does not apply to Heat Recovery Steam Generators (HRSGs) involved with coke ovens.[47] However, the reasoning in this EPA policy determination shows that Subpart Db must apply to the SunCoke Plant. Crucially, the coke ovens involved in the EPA policy determination had "no burners in the duct or the boilers, no combustion air inlets in the boilers, and no supplemental fuels (e.g., natural gas, oil) combusted."[48] In contrast, the SunCoke Plant will use natural gas as a supplemental fuel for steam generation.[49] This is a legally relevant distinction, as the absence of supplemental fuels was central to EPA's reasoning in its policy determination.[50] The Draft Permit must either include appropriate terms and conditions to ensure that the natural gas is not used for steam generation or include in the Permit the terms and *conditions from the appropriate regulations, including Subpart Db.*

Division's Response: The Division does not concur. The referenced NSPS are not applicable because each coke oven matches the definition of a process heater more closely than the definition of a steam generating unit in 40 CFR 60.41b and 40 CFR 60.41c. Further, the HRSGs have zero heat input because there are no burners in the HRSGs.

iv. The Draft Permit also improperly excludes the Acid Rain Program (ARP) by relying upon an inapplicable exemption. 40 C.F.R. § 72.6 exempts cogeneration units from the ARP, provided they supply "equal to or less than one-third [their] potential electrical output capacity or equal to or less than 219,000 MWE-hrs actual electric output on an annual basis to any utility power distribution system for sale."[51] In order to stay under the exemption's 219,000 MWE threshold, the Draft Permit improperly segments the electricity produced from each individual generator.[52] However, the ARP applicability determination must be based on the combined electricity production from all three generators. The exemption applies only to a "generation unit." "Generation unit" and "generator" are not interchangeable terms, as is evident from the fact that Acid Rain regulations contain distinct definitions for each term.[53] Moreover, in prior policy determinations, U.S. EPA has factored multiple generators into a single "generation unit" in calculating whether the unit has exceeded the ARP's 219,000 MWE threshold.[54] If the Division were to base its applicability determination on the combined electricity production from all three generators as required by law, it would conclude that the ARP applies, since the combined electricity production exceeds the MWE threshold. The Permit must be re-drafted to include and ensure compliance with all applicable ARP requirements, including the requirements to apply for and receive an Acid Rain Permit and to monitor and report emissions.[55]

Division's Response: The Division does not concur. Suncoke claims an exemption[1] from the Acid Rain Program under 40 CFR 72.6(b)(4)(ii), which states as follows:

> "For units which commenced construction after November 15, 1990, supplies equal to or less than one-third its potential electrical output capacity or equal to or less than 219,000 MWe-hrs actual electric output on an annual basis to any utility power distribution system for sale (on a gross basis). However, if in any three calendar year period after November 15, 1990, such unit sells to a utility power distribution system an annual average of more than one-third of its potential electrical output capacity and more than 219,000 MWe-hrs actual electric output (on a gross basis), that unit shall be an affected unit, subject to the requirements of the Acid Rain Program."

SunCoke asserts that the annual electricity sold attributable to each HSRG will be less than 219,000 MWe-hrs[2], which implies that Suncoke considers each HSRG separately as eligible for the exemption. This is further clarified in SunCoke's response to Sierra Club's comments:

> "There are several possible definitions of a "unit" which would provide exemptions to the Acid Rain Program. SESS could define a unit as a single coke oven (which would create 120 units) or a contiguous battery of ovens (which would be 30 contiguous ovens and thus would create four units). The simplest and most restrictive is to consider each HRSG (the actual steam generating device) as a "unit", thus resulting in three units. Each HRSG would be considered a unit because

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1 Suncoke indicated that other exemptions are also applicable to the facility but elected not to describe them. See page 4-8 of the application dated December 10, 2012.

2 Page 4-8 of the application dated December 10, 2012.

> it provides the steam that is ultimately converted to electricity and sold. None of these three units will produce "219,000 MWe-hrs actual electric output on an annual basis to any utility power distribution system for sale (on a gross basis)." 40 C.F.R. § 72.6(b)(4)(ii).
>
> SESS's position is bolstered by an EPA December 19, 2008 Determination. See Letter from Clean Air Markets Division, EPA, to Oxbow Calcining LLC (Dec. 19, 2008). A petroleum coke calcining plant had considered attaching new waste heat boilers to three existing kilns in order to produce steam; that steam would flow to a new common steam header connected to a new steam turbine generator to produce electricity for sale. EPA determined that each kiln constitutes a "cogeneration unit" because each kiln was considered a combustion device and because upon implementation of the proposed project, the heat produced in each kiln would be used first to calcine the green pet coke in the kiln and then to produce electricity at the steam turbine. Id at 1—2."

Per the December 19, 2008 EPA Letter:

> "Since one-third of the PEOC for each of kilns (*sic*) (120,596 MWe-hrs each for kilns 1 and 2 and 107,456 MWe-hrs for kiln 3) is less than 219,000 MWe-hrs, under 40 CFR 72.6(b)(4)(ii) each kiln may provide up to an average annual amount of 219,000 MWe-hrs of electrical output for sale to a utility power distribution system in the first year of operation in the proposed project and in each rolling 3-year period starting with that first year and not be considered an affected unit under the Acid Rain Program."

Based upon EPA's clarification, each HRSG can be considered a Unit as that term is used in 40 CFR 72.6(b)(4)(ii). The permit contains language ensuring that the output from each Unit will be less than 219,000 MWe-hrs actual electric output on an annual basis. Please note that in response to the comments from SESS on the draft permit, additional requirements for maintaining the non-applicability of the Acid Rain regulation have been added to the permit.

> *v. The Draft Permit also fails to include adequate mercury controls, which is a critical omission given that the Plant is projected to release approximately 400 lbs of mercury annually. The Statement of Basis contains some discussion of mercury, but ultimately the Permit does not require any additional, mercury-specific controls beyond what the Permit already requires for PM10/PM2.5 emissions.*[56] *The Permit purports to "control" mercury emissions through technology which DAQ mandated as a result of its BACT analysis for particulate matter, which is improper under Kentucky regulations.*[57] *Kentucky's air toxic regulation states that "no owner or operator shall allow any affected facility to emit potentially hazardous matter of toxic substances in such quantities or duration as to be harmful to the health and human welfare of humans, animals and plants."*[58] *A BACT analysis for particulate matter cannot substitute for the health-based determination required for mercury. Neither the Permit nor its supporting material find that 400 lbs of mercury is not harmful to the health and welfare of humans, animals, and plants. The Permit's failure to include a health-based risk analysis is a clear violation of 401 KAR 63:020.*

Division's Response: The Division does not concur. Both the Division and SESS conducted a Toxics impact analysis of mercury emissions and determined that the source is in compliance with 401 KAR 63:020 based on the emission rates of toxics and selection of control technologies stated in the application, and supplemental information submitted by the source. Confirmation of this analysis is found in the Statement of Basis.

vi. The Clean Air Act requires application of Maximum Achievable Control Technology Standards ("MACT") for all hazardous air pollutants, of which mercury is one. See CAA Sections 112(d), 112(b). The "maximum degree of reduction in emissions deemed achievable for new sources shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source." Id. EPA establishes National Emission Standards For Hazardous Air Pollutants (NESHAPs) for source categories, including coke ovens [cite: 68 FR 18007 and 58 FR 57898], which are applicable to this application.

Division's Response: The Division does not concur. See comment III iv. response, above.

vii. Because the proposed coking facility may meet the definition of a facility covered by the utility MATS rule, DAQ must ensure compliance with the rule in its permit, which it has not done. EPA also recently set standards for hazardous air pollutants from coal-fired electric utility steam generating units ("utility MATS rule"), 77 FR 9304 (February 16, 2012) and 78 FR 24073 (April 24, 2013). The utility MATS rule applies to coal-fired electric generating units (i.e., units burning coal more than 10% of the average annual heat input during any 3 consecutive calendar years) of more than 25 megawatts electric that serves a generator that produces electricity for sale. 40 CFR 63.10042. This definition includes a "fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system." Id. Because the proposed facility appears to meet this definition, DAQ must demonstrate the facility's compliance with the utility MATS rule.

37 See, e.g., Draft Permit, at 25, 27, 98.
38 Draft Permit, at 25 (emphasis added). See also id. at 102 ("The emission limitations set forth in 40 CFR 63, Subpart L, shall apply at all times except during a period of startup, shutdown, or malfunction. The startup period shall be determined by the Administrator and shall not exceed 180 days." (emphasis added)).
39 See Draft Permit, at 107.
40 Cabinet Provisions and Procedures for Issuing Title V Permits, available at http://air.ky.gov/SiteCollectionDocuments/52-020%20IBR%20Final.pdf. (emphasis added). See also CAA § 504(a), 43 U.S.C. § 7661c(a) (requiring that every Title V permit "assure compliance by the source with all applicable requirements); 40 C.F.R. §70.1.
41 Draft Permit, at 5.
42 Id.
43 Cabinet Provisions and Procedures for Issuing Title V Permits (emphasis added); CAA § 504(a); 40 C.F.R. §70.1.
44 401 KAR 59:015 § 1(5).
45 See Statement of Basis, at 2 ("The heat released from combusting the gases in the flues and tunnel is routed to Heat Recovery Steam Generators (HRSGs) which use the heat to create steam for running an electricity generating turbine capable of producing 40-75 MW of power.").
46 See Cabinet Provisions and Procedures for Issuing Title V Permits; CAA § 504(a); 40 C.F.R. §70.1.
47 Statement of Basis at 6; U.S. EPA Applicability Determination Index (1999), available at http://cfpub.epa.gov/adi/pdf/adi-nsps-9900003.pdf.
48 Applicability Determination Index.
49 See Draft Permit, at 44. (referencing the natural gas lances).
50 Applicability Determination Index.
51 See 40 C.F.R. 72.6(b)(4).
52 Draft Permit, at 66.
53 See 40 CFR 72.2.
54 See http://www.epa.gov/airmarkets/progsregs/arp/docs/conoco.pdf ("If the 219,000 MWe-hr ceiling is exceeded, then the kilns will become affected units and will have to comply with all applicable requirements under the Acid Rain Program. This includes the requirements to apply for and receive an Acid Rain permit (under 40 CFR part 72) and to monitor and report emissions (under 40 CFR part 75).")
55 See 40 CFR 72; 40 CFR 75.
56 Statement of Basis at 46-47.
57 401 KAR 63:020.
58 Id.

Division's Response: The Division does not concur. See comment III iv. response, above. Furthermore, SESS is not subject to the utility MATS rule (40 CFR 63 Subpart UUUUU) because the permit contains language ensuring that the output from each Unit will be less than 219,000 MWe-hrs actual electric output on an annual basis. Based upon EPA's clarification, each HRSG can be considered a unit as that term is used in 40 CFR 72.6(b)(4)(ii).

IV. The Draft Permit Contains Insufficient Testing, Monitoring, Reporting, and Recordkeeping Requirements to Ensure Compliance with the Permit's Terms and Conditions. (NOTE: To better address the following comments, the Division has divided section IV into smaller sections and numbered them using the i, ii, iii, etc. notation.)

i. Title V permits must include compliance certification, testing, monitoring, reporting and recordkeeping requirements sufficient to assure compliance with the terms and conditions of the permit. 40 CFR § 70.6(c)(1). With respect to monitoring specifically, Title V permits must include "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." 40 C.F.R. § 70.6(a)(3)(i)(B).[59] As the D.C. Circuit recently recognized, infrequent monitoring is insufficient to ensure compliance with a short-term emission limit. Sierra Club v. EPA, 536 F.3d 673, 675 (D.C. Cir. 2008) (noting, as an example, that annual monitoring would not ensure compliance with a daily emissions limit). The NSR Manual likewise emphasizes the necessity of ensuring that emissions limits are practically enforceable. As the Manual states:

To be enforceable, the permit must also specify that the controls be equipped with monitors and/or recorders measuring the specific parameters cited in the permit or those which ensure the efficiency of the unit as required in the permit. Only through these monitors could an inspector instantaneously measure whether a control was operating within its permit requirements and thus determine an emissions unit's compliance. It is these types of additional permit conditions that render other permit limitations practically and federally enforceable.

The Manual also stresses the need to incorporate "continuous, direct emissions measurements" into a permit's monitoring requirements wherever feasible. NSR Manual at H.6.[60]

The Draft Permit fails in many respects to meet the testing and monitoring standards that Title V Permits must satisfy. The Permit's BACT requirements for SO2 improperly rely on a long-term compliance demonstration to protect short-term limits.[61] One operating limitation outlined in the Permit is that "sulfur content, based on a monthly composite sample, shall be limited to 1.3 percent by weight of coal."[62] Using a monthly composite sample to demonstrate compliance with the SO2 standard does not ensure that the 1-hour, 3-hour, and daily SO2 BACT requirements are satisfied.[63] Similarly, the Permit states that charging operations "shall be limited to 20 ovens charged per hour."[64] This is unenforceable, as there are no monitoring or recordkeeping requirements to ensure compliance with the hourly standard. The majority of recordkeeping requirements are based upon a 30-day average, which will not reveal violations of an hourly standard.

59 See also Cabinet Provisions and Procedures for Issuing Title V Permits, incorporated by reference by 401 KAR 52:020. (noting that Title V permits must contain "all emissions monitoring and analysis procedures and test methods that are specified in the applicable requirements, including those in [Section 114 of the Clean Air Act].").
60 See also Sierra Club v. Public Serv. Co., 894 F. Supp. 1455, 1460 (D. Colo. 1995).
61 See Draft Permit, at 20.
62 Id.
63 Additionally, it is not clear if the percentage BACT limit is based upon wet or dry coal. As discussed above, both "wet coal" and "dry coal" must be clearly defined in the Permit to give either term enforceable meaning, and thus comply with applicable regulations.
64 Draft Permit, at 13.
65 Draft Permit, at 36-38.
66 Draft Permit, at 59.
67 Draft Permit, at 12.

Division's Response: The Division does not concur. Compliance with the 1-hour, 3-hour, and daily SO_2 BACT requirements is demonstrated by measurements from the SO_2 CEMS taken every 15 minutes. This ensures both long-term and short-term compliance with the SO_2 standards. Additionally, the limit of 20 ovens per hour is based on the design constraints of the pushing/charging machines. Each machine is capable of only 10 charges per hour. A sentence regarding this has been added to the description of the planned facility in the Statement of Basis.

> *ii. The emission limits for the Quench Tower suffer from similar deficiencies.[65] The Quench Tower operates by rapidly cooling hot coke with water. Despite the fact that there is no wet coal involved in the quench process, the emission limits listed in the Permit are based upon emissions of particulate matter per ton of wet coal. Additionally, the permit appears to require only an initial compliance test with no periodic testing to ensure continuing compliance. By using an improper metric to measure compliance and not requiring sufficient testing, the Permit all but ensures violations of the Quench Tower's emission limits.*

Division's Response: The Division does not concur. The AP-42 PM emission factors are based on coal throughput for the entire process and are not dependent upon the amount of coke actually placed in the tower. However, for clarity, the Division has added a sentence regarding the emission factors basis to the Statement of Basis. Adherence to the requirements of 40 CFR 63, Subpart CCCCC, as required by permit **Section D (B)(1)(d), Compliance Demonstration** of the permit, will ensure compliance with the limits on a continuous basis. However, to further ensure continuous compliance with the PM BACT emission limits, a specific requirement to follow 40 CFR 63, Subpart CCCCC, as required by permit **Section D(B)(1)(e), Compliance Demonstration**, has been added to the continuous compliance demonstration method for PM.

> *iii. The same flaws can be found in the emission limits for SunCoke's cooling towers. Emission rates from cooling towers depend upon the draft rate, circulation water rate, and TDS content of the water. The Permit fails to monitor or set a BACT through limiting TDS content in the circulating water, and it also fails to require periodic testing to ensure that design drift rate is not degrading with time.[66] Many other cooling towers have set TDS limits and required testing or evaluation for drift rates. Omitting these testing and monitoring requirements will fatally undermine the Division's ability to enforce the Permit's terms.*

Division's Response: The Division partially concurs. The drift rate and throughput are included as design requirements and are the BACT. However, an additional BACT TDS limit of 1500 mg/l has been set to ensure emissions of PM are limited to the 0.6 tpy projected by the application calculations. Additionally, a requirement to maintain the drift eliminators in accordance with manufacturer's recommendations for proper operation has been added to monitoring requirements.

> *iv. The Permit also fails to include adequate enforcement provisions for the rated capacity of the coal charging operation. The capacity is listed as "500 ton/hr per machine and 1,226,400 tpy wet coal total."[67] While the permit states that the annual processing limit is meant to be enforceable, the Permit contains no such provisions for the hourly limit.*

Division's Response: The Division does not concur. The listed capacity is based on an operational limitation due to the physical design capacity. SESS is not capable of exceeding the 500 tons of coal per hour 'limitation' because no more than 50 tons of coal per hour per oven may be charged, and the pushing/charging machine is capable of charging no more than ten ovens at 50 tons per oven per hour.

> *v. The Draft Permit cannot be issued as written, as it does not contain compliance*

certification, testing, monitoring, reporting and recordkeeping requirements sufficient to assure compliance with the terms and conditions of the permit. 40 CFR § 70.6(c)(1); 401 KAR 52:020.

Division's Response: The Division does not concur. The draft permit contains operating limitations, compliance demonstration methods, testing requirements, monitoring requirements, recordkeeping requirements, and reporting requirements where appropriate.

V. Ambiguous and Undefined Terms Render Many of the Draft Permit's Provisions Unenforceable.

The Clean Air Act states that Title V permits "shall include enforceable emission limitations and standards," and "shall set forth inspection, entry, monitoring, compliance certification, and reporting requirements to assure compliance with the permit terms and conditions." 42 U.S.C. § 7661c(a) and (c); 40 C.F.R. § 70.6(c)(1). For a permit condition to be enforceable, the permit must leave no doubt as to what, exactly, the permittee must do to satisfy that condition. As EPA has explained,

> *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 intentionally or unintentionally prevent enforcement.*

U.S. EPA Region 9 Title V Permit Review Guidelines (Sept. 9, 1999), at III-46. See also 401 KAR 50:055.

Many of the Draft Permit's terms are unenforceable as written, either because they are not defined or because they are ambiguous. Issuing vague or undefined permit terms will not ensure compliance with the Draft Permit's conditions, and thus violates the CAA and its implementing regulations.[68] The Permit's ambiguous and\or undefined terms include, but are not limited to:

- *"Wet tons of coal"/"wet coal."[69] Wet coal may be a term of art in the coal or coking industry, but it must be defined in reference to a U.S. EPA definition or a published industry standard in order to be practically enforceable. The definition of wet coal should include the ways in which it is different from "dry coal."*
- *"Normal operation."[70] This phrase is not explicitly defined in the Draft Permit, and thus is vague and unenforceable. Without a definition that confers enforceable specificity to that term, SunCoke is effectively allowed to use the most favorable, selectively-picked data to demonstrate compliance even if that data is not representative of the Plant's typical operations.*
- *"Pounds per dry ton coal."[71] BACT for various pollutants is listed in the format of "lbs/dry ton coal." It is unclear how wet coal is different from dry coal, and how to convert between the two metrics. The conversion rate, as well as the data necessary to make the conversion calculation, must be specified in the Permit.*

The Division's failure to define key terms in the Draft Permit makes it unenforceable as a practical matter. The Division must re-issue the Draft Permit and rectify these ambiguities and omissions.

Division's Response: The Division concurs and has amended the Statement of Basis to incorporate the requested definitions.

VI. The Draft Permit Fails to meet Public Participation Requirements. (NOTE: To better address the following comments, the Division has divided section VI into smaller sections and numbered them using the i, ii, iii, etc. notation.)

i. The Draft Permit contains multiple public notice defects which alone is grounds for re-issuing the permit and restarting the public comment process. 401 KAR 52:100 governs the public notice procedures which Title V Air Permit Applicants must follow.[72] The purpose of the public notice process, as delineated by 401 KAR 52:100, is to allow members of the public to have meaningful input on permitting activities which will affect their communities. Multiple defects in the Draft Permit contravene both the purpose and plain language of the public notice procedures, as delineated in 401 KAR 52:100.

First, the Draft Permit does not contain the address of the proposed facility, as is required by regulation. 401 KAR 52:100 § 5(2) clearly states that among the mandatory information required in a public notice is the "Name and address of the permit applicant and, if different, the name and address of the facility." The Draft Permit lists the location of the plant as "US 23, Greenup County, KY."[73] This might describe a location as far as 25 miles from the city of South Shore, as US 23 is within Greenup County lines approximately 25 miles southeast of South Shore, around Flatwoods, KY. This ambiguity regarding location does not give Kentucky residents adequate information about whether the proposed facility will located near them, a factor which would likely be relevant in a resident's decision to comment on the Draft Permit. Because listing a multi-mile stretch of country road does not qualify as an "address" per the terms of 401 KAR 52:100 § 5(2), the Draft Permit fails to satisfy public notice requirements.

68 See 42 U.S.C. § 7661c(a) and (c); 40 C.F.R. § 70.6(c)(1); 401 KAR 51:055.
69 See Draft Permit, at 6.
70 See Draft Permit, at 12. ("Compliance with the BACT determination for SO2 emissions shall be demonstrated by monitoring the sulfur content of the coal during normal operations.")
71 See Draft Permit, at 13. The SunCoke Plant will emit PM, PM10, PM2.5, CO, VOC, SO2, and GHGs in significant amounts for PSD\BACT purposes.
72 See 401 KAR 52:020 § 25.
73 Cite to page # in permit.

Division's Response: The Division does not concur. SESS provided both UTM coordinates and an aerial map of the proposed site as part of the permit application, and these materials were made available for inspection to the public in both the local library and DAQ regional offices. This information unambiguously defines the planned facility location.

ii. The second flaw with the Draft Permit's public notice is its failure to list the degree of increment consumption. The Draft Permit is required, under 401 KAR 52:100 § 5(10), to include "the degree of increment consumption expected to occur" from the construction of a new or modified source. This requirement applies to both Class I and Class II increments.[74] The Draft Permit reports the cumulative increment consumption from all new sources in the region, but does not provide the degree of increment consumption expected to occur with respect to this project. The increment consumption referenced by 401 KAR 52:100 §5(10) is project-specific, since it applies to "permits subject to review under [PSD regulations]," and those permits are reviewed on an individual, project-specific basis. The Draft Permit's region-wide increment consumption reporting thus fails to comply with the public notice requirement listed in 401 KAR 52:100 § 5(10).

Division's Response: The Division does not concur. The regulation 401 KAR 52:100, Section 5(10) requires a permit subject to review under 401 KAR 51:017 to include the degree of increment consumption expected to occur. The word “degree”, as used in the regulation, means the “extent” of the increment consumption or the amount of increment consumption. The regulation 401 KAR 51:017, Section 9, Source Impact Analysis requires the owner or operator of the proposed source or modification to demonstrate that allowable emissions increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reductions, including secondary emissions, shall not cause or contribute to air pollution in violation of:

(a) A national ambient air quality standard in an air quality control region; or
(b) An applicable maximum allowable increase over the baseline concentration in any area.

The phrase “all other applicable emission increases” includes cumulative increment consumption from all new sources in the region. This increment consumption modeled is compared to the 401 KAR 51:017, Section 2. Those are the values that are listed in the public notice dated December 26, 2013 that demonstrate the “degree” or the “extent” of increment consumption.

VII. Conclusion

For all the above reasons, the Draft Permit is deficient and does not meet CAA requirements. Consequently, the permit application must be denied pending compliance with all legal requirements.

Division’s Response: The Division does not concur.

Commonwealth of Kentucky
Division for Air Quality

COMMENTS AND RESPONSES

ON THE STATEMENT OF BASIS

ATTACHMENT 1

SESS Comments on SunCoke Energy South Shore Statement of Basis V-13-007, Plant ID 021-089-00047, Agency Interest No. 105793

David J. Schwake
Director, North America
Business Development

SunCoke Energy, Inc.
1011 Warrenville Road
Suite 600
Lisle, IL 60532
630-824-1000 Phone
630-824-1001 Fax

January 24, 2014

Mr. James Morse
Division for Air Quality
200 Fair Oaks Lane, 1st Floor
Frankfort, KY 40601

RE: Permit Statement of Basis and Summary for SunCoke Energy South Shore

Permit:	V-13-007
Agency Interest:	105793
Activity:	APE20120001
Source ID:	21-089-00047

Dear Mr. Morse:

In addition to the comments submitted to the agency concerning the draft permit, SunCoke is also providing comments on the Permit Statement of Basis for the South Shore facility issued by the Division on December 26, 2013. The comments have been added in the attached document. The Permit Summary document should also be adjusted accordingly.

If you have any questions or need additional information, please contact me at (630) 824-1000.

Sincerely,

David J. Schwake

Enclosure

Commonwealth of Kentucky
Division for Air Quality

PERMIT STATEMENT OF BASIS

Title V, PSD, Construction/Operating
Permit: V-13-007
SunCoke Energy South Shore, LLC
South Shore, KY 41175
November 27, 2013
Sandra M. Cooke, Reviewer

SOURCE ID:	21-089-00047
AGENCY INTEREST:	105793
ACTIVITY:	APE200120001

1. SOURCE DESCRIPTION:

SunCoke Energy South Shore, LLC (SESS), owned by SunCoke Energy, Inc., has applied to construct and operate a metallurgical coke production and heat recovery electrical plant in Greenup County, Kentucky. The facility will be located on an approximately 254 acre site, consisting of coal handling and preparation equipment, heat recovery coke ovens, coal charging, coke pushing and handling equipment, a quench tower, coke storage facilities, various administrative and support buildings, and associated air pollution control equipment. In addition, waste heat recovery steam generators (HRSGs) and a steam turbine will be installed to recover heat from the process gases to produce electricity.

The coking process involves heating coal in ovens to drive off volatile compounds until only the carbon and ash remain. Heat recovery ovens then oxidize (burn) the volatiles to produce heat for creating steam to drive steam turbines that produce electricity.

Coal is received via barges on the river. At the unloading station, the coal is removed from the barge and loaded into a coal hopper, which discharges the coal onto a partially covered conveyor that transports the coal to the storage area on the plant site. At the storage area, coal is placed in one of four piles by a radial stacker arm that adjusts to minimize the drop height of the coal and therefore minimize emissions. A crane or a front end loader moves coal from the piles to a conveyor that transports the coal to the coal crushing building. This equipment is also designed and used to minimize the drop height of the coal. Coal received from the storage piles enters the coal crushing building, where the coal is reduced to the appropriate size for use in the ovens and transferred to the East and West storage bins before coking

A mobile charging/pushing machine is loaded with the crushed coal, which then charges the coal into an oven in one of the two batteries of ovens. There are 120 coke ovens arranged in two separate banks, East and West, with a combined capability of carbonizing up to 1,226,400 tons per year (tpy) of coal and producing up to 831,100 tpy of metallurgical coke. The pushing/charging machine is equipped with a traveling hood/baghouse system to control charging emissions that escape from the negatively pressured ovens. The ovens are kept at negative pressure to minimize emissions and allow the intake of additional air to aid in the carbonization process.

Once the crushed coal is loaded into an oven, the coal is heated (temperatures of 1,600°F to 2,400°F) to vaporize combustible volatile compounds. The gases are pulled through sole flues, and the common tunnel, where combustion of the gas is completed to release heat and destroy some pollutants. Natural gas lances may also be used through ports to boost heat in the ovens and/or afterburner tunnel to keep them hot during maintenance activities and during extremely cold weather. The heat released from combusting the gases in the flues and tunnel is routed to Heat Recovery Steam Generators (HRSGs), which use the heat to create steam for running an electricity generating turbine capable of producing 40-75 MW of power. It is possible that the natural gas lances may be needed to augment the heat going to the HRSGs in a non-routine situation requiring extra power production.

The HRSGs also serve to cool the gases to protect the downstream emission control devices placed before the main emission stack. Three HRSGs will be in use on this site to allow for maintenance/repair without direct flue gas release to atmosphere.

At the ovens, the coal to coke cycle takes 48 hours for each bed of 48 to 50 tons or 24 hours for each bed of 28 tons. Once the volatiles have been completely released from the coal, the material bed has become coke and is ready for pushing and quenching.

A mobile machine pushes the hot, coke loaf onto a mobile flat push hot car. The coke then travels to the end of the battery where the bed is transferred to a quench car. ~~Each of the two~~The flat push hot cars is equipped with a multicyclone to capture pushing emissions. The flat push hot car travels to a stationary quench tower at the end of the oven batteries where the intact coke loaf is drenched with water. Emissions are controlled through the use of water containing a low amount of total dissolved solids and through a special baffle design used in the tower.

After quenching, coke may be transferred to the coke crushing and screening building, where the coke is sized for different applications. Screening separates the different sizes of coke and the enclosure and baghouse filters help control emissions at this point. Coke that does not go immediately to crushing and screening is transferred to the coke storage pile, where a radial stacker minimizes coke drop height and thereby minimizes emissions. A front end loader moves coke, as needed, from the pile to a conveyor that supplies the crushing and screening building. Undersized coke (breeze) is stored in bunkers. Coke product maybe loaded into railcars or trucks for delivery to purchasers and unsold breeze may be recycled by blending it into coal charge. The site will also have roadways, storage silos, storage tanks, support buildings, and a cooling tower associated with the turbine. Diesel engines will power cranes, emergency generators, and fire pumps.

During Start-up, temporary natural gas burners are used at each oven to begin the heating, dry-out and curing of the silica bricks and cast refractory materials in the ovens, crossover tunnel, HRSG header and emergency stacks. With the loading of a full charge of metallurgical coal, the gas burners are permanently removed and the brick and refractory materials are heated to full operating temperature. Start-up occurs one bank of 60 ovens at a time to accommodate limits on natural gas make-up availability. Start-up can occur only once as coke ovens cannot be shut-down and restarted without shortening the service life of the equipment. Repeated heating and cooling will cause thermal spalling and even structural failure of the ovens.

The new facility is expected to be a source of both stack and fugitive emissions of criteria pollutants Particulate Matter (PM), Particulate Matter 10 microns diameter and smaller (PM_{10}), Particulate Matter 2.5 microns diameter and smaller ($PM_{2.5}$), Sulfur Dioxide (SO_2), Nitrogen Oxides (NOx), Carbon Monoxide (CO), Volatile Organic Contaminants (VOCs), and Lead (Pb) as well as the Hazardous Air Pollutants (HAPs) including, Hydrochloric Acid (HCl), Mercury (Hg) and various other HAPs in small amounts. Greenhouse gases (GHGs) will also be emitted, ~~due mostly to the use of natural gas as a fuel,~~ and will be comprised of mostly Carbon Dioxide (CO_2). The other GHGs expected from the processes include small amounts of methane and Nitrous Oxide (N_2O). Finally, two pollutants, gaseous fluorides (HF) and hydrogen sulfides (HS), are expected to be emitted below Kentucky ambient air quality standards.

Comment [JC1]: Most GHGs are not due to natural gas.

The project emissions, proposed controls, and potential air quality impacts are discussed in greater detail in sections **4. Emissions**, **5. BACT Analysis**, and **6. Air Quality Impact Analysis**, below.

2. APPLICATION SUMMARY

The Division received an application for a metallurgical coke production facility to be located in Greenup County, Kentucky, on December 10, 2012, and a protocol of the air dispersion modeling files CD was received on January 22, 2013.

The Division issued a technical Notice of Deficiency (NOD) on January 25, 2013. The notice requested additional information and some clarifications to assist in review of the application. A response, addressing the NOD was received from SESS on February 22, 2013.

Additional information submittals, generally addressing telephone conversations and requests for clarifications, were received by the Division on May 31, June 28, and July 11, 2013.

An Additional NOD, regarding diesel engines, was issued by the Division on June 3, 2013, with responses from SESS received by the Division on June 28 and July 2, 2013.

An NOD regarding the air dispersion modeling was issued by the Division on March 19, 2013, with an extension allowing for extra time to answer issued by the Division on April 25, 2013. Additional information addressing the air dispersion modeling input questions was received June 24, 2013. A final NOD regarding the modeling was issued on August 5, 2013, with SESS responding on October 10, 2013.

U.S. EPA, which received a copy of the application and modeling files on February 7, 2013 made comments on the modeling on May 1, 2013, and on the application on June 28, 2013. SESS addressed the U.S. EPA questions about the application on July 19, 2013.

SESS requested an ambient monitoring waiver June 17, 2013, and received a response from the

Division on July 25, 2013. Preconstruction monitoring for NO_2 and $PM_{2.5}$ were waived and ambient monitoring data from Ohio was declared acceptable for PM_{10} and SO_2.
The permit application was declared complete on August 8, 2013.

The Federal Land Manager (FLM) acknowledged receipt of the application and initial air modeling files on August 13, 2013.

The air dispersion modeling was completed on December 10, 2013.

3. REGULATORY ANALYSIS

A. APPLICABLE REGULATIONS

401 KAR 60:005, *40 CFR Part 60 standards of performance for new stationary sources,* incorporates the following two applicable regulations:

40 CFR 60, Subpart Y, *Standards of Performance for Coal Preparation Plants.* This New Source Performance Standards (NSPS) regulation applies to Group I, coal transfer equipment, emission units EU01 through EU04. This regulation establishes opacity limits and requires a fugitive coal dust emissions control plan to be submitted and implemented. (Incorporated by 401 KAR 60:005, *Part 60 standards of performance for new stationary sources*)

40 CFR 60, Subpart IIII, *Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.* This NSPS regulation applies to emergency and non-emergency engines of various sizes on the site, including EU24 (Emergency Engine A, Fire Pump), EU25 (Emergency Generator B), EU26 and EU27 (Emergency Generators C and D), and EU28 and EU29 (Cranes E and F). This regulation establishes emissions, testing and fuel standards for the subject stationary internal combustion engines.

401 KAR 63:002, *40 CFR Part 63 national emission standards for hazardous air pollutants,* incorporates the following three applicable regulations:

40 CFR 63, Subpart L, *National Emission Standards for Coke Oven Batteries.* This MACT is applicable to the Group II Processes and Equipment EU05 and EU06 (Coal Charging East and West), EU07 (Coking), EU08 (Coke Pushing), and Coking Process Start-Up (including EU12, Temporary Natural Gas Burners). This regulation establishes operating, emissions and opacity limits and requires the installation of control equipment to minimize emissions from charging. This plan also calls for establishment of a work practice plan as well as a startup, shutdown and malfunction plan.

40 CFR 63, Subpart ZZZZ, *National Emissions Standards for Hazardous Air Pollutants for* Stationary Reciprocating Internal Combustion Engines. This MACT regulation applies to emergency and non-emergency engines of various sizes on the site, including EU24 (Emergency Engine A, Fire Pump), EU25 (Emergency Generator B), EU26 and EU27 (Emergency Generators C and D), and EU28 and EU29 (Cranes E and F). It establishes emission and operating limitations for the subject stationary engines as a means to limit hazardous air pollutants (HAP) emitted by the reciprocating internal combustion engines (RICE) located at this major sources of HAPs.

40 CFR 63, Subpart CCCCC, *National Emission Standards for Hazardous Air Pollutants for Coke Ovens: Pushing, Quenching, and Battery Stacks.* This Maximum Achievable Control Technology (MACT) standard is applicable to the Group II Processes and Equipment EU08 (Coke Pushing), and EU09 (Quench Tower). The regulation sets various operating and emission limits as well as testing, parametric monitoring and recordkeeping requirements for the equipment. No applicable requirements from this subpart apply to Coking (EU07) and Emergency Stacks/Lids (EU10).

40 CFR 64, *Compliance assurance monitoring* (CAM). This regulation requires that sources monitor and maintain their control devices to ensure continuing compliance with pollutant specific emissions limitations. It is applicable to emission units that are subject to an emission limitation, use control devices to achieve compliance, and have pre-control emissions that exceed a major source threshold. For this project, the CAM plan applies to the Circulating Dry Scrubber/Baghouse control used for the main coking gas stack for both SO_2 and PM.

40 CFR 98, *Mandatory Greenhouse Gas Reporting* (GHGs). This regulation requires that sources report the amounts of GHGs emitted annually. This regulation is applicable to this project under the source category requirements, i.e. Coke production is part of the Iron and Steel Production source category under **40 CFR 98, Subpart Q**, *Iron and Steel Production.* See Greenhouse Gases under **4. Emissions**, below, for additional information regarding GHGs.

401 KAR 52:020, *Title V permits.* This Kentucky Administrative Regulation (KAR), establishes requirements for air contaminant sources located in Kentucky that are required to obtain a Title V permit consistent with the requirements of title V of the Clean Air Act (42 U.S.C. 7401, et seq.). This project requires a Title V permit due to its classification as a major source, i.e. it has the potential to emit 100 tons or more of a regulated air pollutant (PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, and CO) and it has the potential to emit 10 tons or more of a hazardous air pollutant (HCl) or a combination of hazardous air pollutants equal to or in excess of 25 tons (HCl and small amounts of other HAPs).

401 KAR 51:017, *Prevention of significant deterioration of air quality.* This KAR provides for the prevention of significant deterioration (PSD) of ambient air quality. It is applicable to the project and requires that a best available control technology (BACT) analysis be performed and controls (if feasible) be applied for the PSD pollutant(s). For this project, the potential to emit PM, PM_{10}, $PM_{2.5}$, SO_2, NOx, CO, VOCs, GHGs, and H_2SO_4 all exceed the pollutant specific PSD significant emission rates. See **5. BACT ANALYSIS**, below, for additional information regarding the application of this regulation.

401 KAR 59:010, *New Process Operations.* This KAR provides for the control of particulate emissions from new process operations not subject to another particulate standard within Chapter 59 of 401 KAR. It establishes for emission limits for PM and opacity standards based on the weight of materials processed through the affected facility. This regulation is applicable to several emissions units in the project including EU05 and EU06 (Charging East and West), EU07 (Coking), EU08

(Coke Pushing), EU15 (Coke Crushing and Screening), EU19 (Cooling Tower), EU20 (Lime Storage Silo), EU21 (Hydrated Lime Storage Silo), EU22 (Flue Gas Desulfurization Ash Storage Silo).

401 KAR 63:010, *Fugitives*. This KAR provides for the control of fugitive emissions. Fugitive emissions are those released into open air rather than from a stack or control exhaust. This regulation requires controls for preventing particulate matter from becoming airborne and visible emissions from crossing the lot line of properties on which emissions originate. This KAR applies to the Group I Coal Transfer Equipment, EU09 (Quench Tower), Group III Coke Transfer Equipment, EU17 and EU18 (Paved and Unpaved Roads)~~, and EU19 (Cooling Tower)~~,

401 KAR 63:020, *Toxic Substances*. This KAR provides for control of emissions of potentially hazardous matter and toxic substances. Toxic substances are those which may be harmful to the health and welfare of humans, animals, and plants and this regulation forbids any source from emitting these substances in a quantity or for a duration that could be detrimental. This regulation was used in evaluating the impact of the Group II EU07 (Coking) equipment. The equipment has a potential to emit 117 tpy of HCl and 0.202 tpy of Hg.

401 KAR 59:105, *New process gas streams*. This regulation provides for control of emissions from new process gas streams. It applies specifically to the Group II EU07 (Coking) equipment ~~and EU26 (Emergency Stacks/Lids) with respect to SO_2. only.~~

Comment [JC2]: Not applicable

B. NON-APPLICABLE REGULATIONS:

40 CFR 60, Subpart Db, *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units*. This NSPS is not applicable due to the U.S. EPA determination that neither the coke ovens nor the waste heat boilers meet the definition of a steam generating unit for the purposes of Subpart Db. An applicability determination for a heat recovery coke oven, dated 01/14/1999, control number 9900003, provides the U.S. EPA position that Subpart Db is not applicable to this type of coke oven.

40 CFR 63, Subpart Q, *National emissions standards for hazardous air pollutants for Industrial Process Cooling Towers*. This MACT is precluded from applicability by the source demonstrating that no chromium-based water treatment chemicals are used in the cooling tower (EU~~17~~19). Operating limitations, as well as testing and recordkeeping requirements have been applied to this unit to preclude applicability of this MACT.

4. EMISSIONS

The potential emissions of regulated air pollutants have been estimated and are presented in the following table. A discussion of each pollutant, sources, calculation assumptions and source of emission factors used follows. A brief description of the PSD analysis of each pollutant is also included, though additional information regarding PSD requirements as a consequence of the emission levels is discussed more thoroughly in the section **5. BACT ANALYSIS**, below. Note that Hg and HCl are not PSD pollutants, but have been analyzed for best control technologies by SESS.

Table 1

Pollutant	PTE Tons per year	Significant Emission Rate Tons per year	PSD Applicability
PM (filterable, only)	174.8	25	Yes
PM_{10} (filterable and condensable)	208.3	15	Yes
$PM_{2.5}$ (filterable and condensable)	160.0	10	Yes
CO	218.3	100	Yes
VOC	44.7	40	Yes
SO_2	634.0	40	Yes
NOx	692.9	40	Yes
Pb	0.22	0.6	No
H_2SO_4	33.396	7	Yes
GHGs (CO_2e)	1,374,000	75,000	Yes
Hg	0.202	NA	NA
HCl	117.48	NA	NA

Comment [JC3]: Revised with values from application and supplemental information.

Particulate Matter (PM, PM_{10}, $PM_{2.5}$)

For the SESS project, particulate emissions calculations include three different types: PM (all sizes, filterable only), PM_{10} (filterable and condensable) and $PM_{2.5}$ (filterable and condensable). With the exception of the Heat Recovery Steam Generators (HRSGs, EU23), all equipment included in permit Section B – EMISSION UNITS, EMISSION POINTS, APPLICABLE REGULATIONS, AND OPERATING CONDITIONS are sources of particulate emissions.

The Group I Coal Transfer equipment [Emission Unit (EU01) through EU04] is a source of $PM/PM_{10}/PM_{2.5}$ as fugitive emissions (i.e. emissions are released to the open air other than from a stack or the exhaust of a control device). Reduction of the amount of fugitives emitted is achieved through the use of controlled drop heights for coal, wetting of materials, wind screens, and enclosure or partial enclosure of coal handling activities (where possible). All emissions calculations for these emission points are based on chapters 12 and 13 of the U.S. EPA's AP-42, *Compilation of Air Pollutant Emission Factors, Volume I, Fifth Edition* (AP-42) and on *Controls of Open Fugitive Dust Sources*, EPA-450/388-008. Particulate emissions for Group I equipment are estimated at ~~6.92~~6.21 tpy of PM, ~~3.29~~2.96 tpy of PM_{10}, and ~~0.58~~0.53 tpy of $PM_{2.5}$.

The Group II Coking Processes and Equipment (EU05 to EU12) are also a source of $PM/PM_{10}/PM_{2.5}$ and with the exception of the Quench Tower (EU09), all PM is emitted through a stack or the exhaust of a control.

For Charging (EU05, EU06), the baghouse stack emission factor for PM is derived from the MACT standard, i.e., the emission factor is calculated based on the maximum amount of PM that the emission unit is allowed to emit, including controls. The BACT analysis determined that the BACT limit for PM of 0.0081 lb/ton of dry coal is the same value as that in the MACT and is consistent with the BACT limits currently in the RACT/BACT/LAER Clearinghouse Data Base. The permit requires that the facility conduct stack tests to show compliance. The emission factors for both PM_{10}

and $PM_{2.5}$ are derived from the assumption that condensable PM_{10} and $PM_{2.5}$ are 50 percent of the filterable and these emission factors are therefore 1 and ½ times the factor for PM, which is filterable, only. These assumptions are conservative, will be tested, and the Division finds them acceptable for use in calculating the potential to emit.

Charging emission factors for fugitives are based on AP-42, Chapter 12.2 Coke Production, Table 12.2-21, uncontrolled filterable PM. Emission factors for PM_{10} and $PM_{2.5}$ are then based on an assumed percentage (30 and 15 percent, respectively) of PM filterable. These assumptions are standard regarding PM_{10} and $PM_{2.5}$, and are therefore acceptable.

Coking (EU07) is subject to a BACT limit of 0.005 gr/dscf, which is comparable to the BACT limits currently in the RACT/BACT/LAER Clearinghouse Data Base (see Gateway Energy and Coke Company). Using an engineering estimate, the PM_{10} and $PM_{2.5}$ emission factors are based on a percentage of the PM emission factor. Since the emissions will be measured through testing, the Division finds them acceptable for use in calculating the potential to emit.

The Pushing (EU08) emissions for PM are subject to the MACT (40 CFR 63, Subpart CCCCC) limit of 0.04 lb/ton of coke if a mobile control device captures the emissions during travel. An engineering estimate has been used for establishing the emission factor for PM_{10} and $PM_{2.5}$. Condensable PM is assumed to be 50 percent of the filterable, and $PM_{2.5}$ is conservatively assumed to be the same as PM_{10}. The Division finds this acceptable.

For Quenching (EU9), the emission factor for PM is based on emission factors found in AP-42, Chapter 12.2, Coke Production, Table 12.2-12 and an assumption of total dissolved solids (TDS) in the quench water of 1,100 mg/L (a BACT limit). PM_{10} and $PM_{2.5}$ are a percentage of PM. Since TDS will be a tested limit, these emission factors are acceptable.

The Emergency Stack/Lids (EU10), each of which may be exercised for up to 30 minutes each month, have been conservatively estimated to emit up to the maximum allowed for Gateway Energy and Coke Company. This is conservative since there should be no emissions from the emergency stacks during monthly lid testing due to the fact that the induced draft fan will be operating at the main stack during testing (a BACT operational requirement).

For Natural Gas Lances/Spargers (EU11), emission factors for all the PM types are based on AP-42, Chapter 1.4, Natural Gas Combustion. Emission totals are based on these factors and a BACT fuel use limit. The emission factors used are standard and are therefore acceptable.

The Group III Coke Transfer equipment (EU13 through EU16), similar to Group I, emits particulate pollutants and mostly in the form of fugitives. EU15, Coke Crushing and Screening building, is the only point in the group with an emissions stack. EU15 is enclosed in a building and controlled with a baghouse filter. Control of the fugitive PM, where possible, is achieved through full or partial enclosure, wetting of materials and reduction of drop height for the coke onto the storage piles.

Except for EU15, all emission factors for this group are based on AP-42, Chapter 13.2.4, Aggregate

Handling and Storage Piles, or on the U.S. EPA guidance document, "Controls of Open Fugitive Dust Sources", EPA-450/388-008, September 1988, Chapter 6. Coke crushing and screening (EU15) emission factors are based on an engineering estimate of the total PM, PM_{10} and $PM_{2.5}$ that will be emitted. The calculations for emission are based on the BACT PM grain loading limits established for the baghouse associated with EU15. Since the baghouse will be tested to prove compliance with the limits, these emission factors are acceptable.

Group IV roadway emissions (EU17 and EU18) are fugitive PM generated through vehicle activity on both paved and unpaved roads. Emissions are controlled through regular flushing of silts and dusts from pavement and the use of chemical suppressants and water on unpaved surfaces. Emissions have been calculated using standard methods found in AP-42, Chapter 13, Miscellaneous Industries (13.2.1 Paved Roads and 13.2.2 Unpaved Road).

The Cooling Tower (EU19) is a source of PM from the drift, or water droplets that are carried out of the cooling tower with the exhaust air. Drift droplets have the same concentration of impurities as the water entering the tower. In order to control the amount of PM produced, the tower will be designed to limit drift (water loss) to 0.0005 percent. The emissions for the cooling tower have been calculated using the proposed water throughput, the known total dissolved solids (i.e. amount of impurities in the water to be used), and the tower drift (evaporative losses). The Division finds the calculation method acceptable.

The Group V storage silos (EU20 through EU22) emit $PM/PM_{10}/PM_{2.5}$. Calculations for the Lime and Hydrated Lime silos are based on AP-42 and achieve 99 percent control efficiency through the use of bin vents with filters. The emission factor for each silo and type of PM is assumed to be similar to that of product transfer and conveying. The Lime and Hydrated Lime silo emission factors are based in AP-42, Chapter 11.17, Lime Manufacturing and the Flue Gas Desulfurization Ash Storage Silo emission factors are based in Chapter 13.2.4, Aggregate Handling and Storage Piles.

All Stationary Internal Combustion Engine (EU24 through EU29) particulate emissions have been calculated using AP-42, Chapter 3.3, Gasoline and Diesel Industrial Engines emission factors.

Comment [JC4]: Used values from 40 CFR 60, Subpart IIII in application.

$PM/PM_{10}/PM_{2.5}$ PSD Analysis

The emissions calculations, using the planned throughputs and accepted emission factors for each piece of equipment, estimate that potential emissions for the project are ~~172.15~~174.8 tpy for PM (filterable), ~~216.63~~208.3 tpy for PM_{10}, and ~~157.03~~160.0 tpy for $PM_{2.5}$. These emission rates exceed the PSD significant emission rates of 25 tpy for PM, 15 tpy for PM_{10} and 10 tpy for $PM_{2.5}$. Therefore, Best Available Control Technology (BACT) analyses for these pollutants are required. See sections **5. A**, and **5. B**, below, for a discussion of the BACT for $PM/PM_{10}/PM_{2.5}$ and fugitive $PM/PM_{10}/PM_{2.5}$.

Carbon Monoxide (CO)

The Group II Coking Processes are a source of CO emissions with the exception of the Quench Tower (EU09). ~~There are no c~~Controls for CO in this group of equipment are based on good combustion practices.

Emission calculations of CO for Charging (EU05, EU06) are based on Stack test data at a similar heat recovery coking battery at a SunCoke site known as Jewell, located in Vansant Virginia. The Coking (EU07) and Emergency Stacks/Lids testing (EU10) emission factors for CO are based on the emission limit at the similar facility Haverhill North Coal Company, located in Franklin Furnace, Ohio. Calculations for CO emissions due to Pushing (EU08) are based on AP-42, Chapter 12.2, Coke Production. Emission factors for the Natural Gas Lances/Spargers (EU11) are from AP-42, Chapter 1.4, Natural Gas Combustion.

All Stationary Internal Combustion Engine (EU24 through EU29) CO emissions have been calculated using AP-42, Chapter 3.3, Gasoline and Diesel Industrial Engines emission factors.

Comment [JC5]: Used values from 40 CFR 60, Subpart IIII in application.

CO PSD Analysis

The emissions calculations, using the planned throughputs and accepted emission factors for each piece of equipment, estimate that potential CO emissions for the project are ~~260.35~~218.3 tpy. This emission rate exceeds the PSD significant emission rate of 100 tpy for CO. Therefore, a BACT analysis and a limit for this pollutant are required for CO emissions. See section **5. C**, below, for a discussion of the BACT for CO. (Note: The same BACT Analysis section also contains the discussion for VOCs)

Volatile Organic Compounds (VOC)

As with the CO emissions, the **Group II** Coking Processes are a source of VOCs, with the exception of the Quench Tower (EU09).

Potential emissions of VOC from Charging (EU05, EU06) are based on stack test data at a similar heat recovery coking battery at a SunCoke site known as Jewell, located in Vansant Virginia. The Coking (EU07) and Emergency Stacks/Lids testing (EU10) emission factors for VOCs are based on the emission limit at the similar facility Haverhill North Coal Company, located in Franklin Furnace, Ohio. Calculations for VOC emissions due to Pushing (EU08) are engineering estimates based on test data from similar SunCoke facilities. Emission factors for the Natural Gas Lances/Spargers (EU11) are from AP-42, Chapter1.4, Natural Gas Combustion.

All Stationary Internal Combustion Engine (EU24 through EU29) CO emissions have been calculated using AP-42, Chapter 3.3, Gasoline and Diesel Industrial Engines emission factors

Comment [JC6]: Used values from 40 CFR 60, Subpart IIII in application.

VOC PSD Analysis

The emissions calculations, using the planned throughputs and accepted emission factors for each piece of equipment, estimate potential VOC emissions for the project to be ~~43.11~~44.7 tpy. This emission rate exceeds the PSD significant emission rate of 40 tpy for VOC. Therefore, a BACT analysis and a limit for this pollutant are. See section **5. C**, below, for a discussion of the BACT for VOC. See section **5. C**, below, for a discussion of the BACT for CO. (Note: The same BACT Analysis section also contains the discussion for CO)

Sulfur Dioxide (SO_2)

The Group II Coking Processes are a source of SO_2 with the exception of the Quench Tower (EU09). SO_2 emissions due to coking are controlled at the main stack through the use of a Circulating Dry Scrubber that utilizes lime.

As with CO and VOC emissions, the calculations of SO_2 due to Charging (EU05, EU06) are based on Stack test data from the Jewell facility in Vansant, VA. The Coking (EU07) and Emergency Stacks/Lids testing (EU10) emission factors for SO_2 are based on a material balance. Since the average sulfur content of the coal to be used is a limit in the permit, emission calculations are based on the amount of coal processed and the amount of sulfur contained within that coal. Calculations for SO_2 emissions due to Pushing (EU08) are based on data from the Haverhill facility in Ohio. Emission factors for the Natural Gas Lances/Spargers (EU11) are from AP-42, Chapter1.4, Natural Gas Combustion. Since existing test data from a similar plant is used in calculating SO_2 emissions from Charging and Pushing, Coking emissions will be verified through stack testing, conservative assumptions were made for the Emergency Stacks/Lids calculations, and the Natural Gas Lances/Spargers emission are based on standard AP-42 emission factors, the Division finds the calculations for Group II SO_2 emissions acceptable.

All Stationary Internal Combustion Engine (EU24 through EU29) SOx emissions (conservatively assumed to all be SO_2 for this project) are calculated using AP-42, Chapter 3.3, Gasoline and Diesel Industrial Engines emission factors. No controls are planned for the emergency and non-emergency engines. The emission factors used are standard and are therefore acceptable.

SO_2 PSD Analysis

Based on the accepted emission factors and calculations, the total emissions of ~~644.58~~634.0 tpy of SO_2 exceed the PSD significant emission rate of 40 tpy for this pollutant. Therefore, SunCoke is required to perform a BACT analysis for SO_2. See section **5.D**, below, for a discussion of the BACT for SO_2.

Nitrogen Oxides (NOx)

The Group II Coking Processes are the primary source of NOx for this project, with the exception of the Quench Tower (EU09). There are no add-on controls for NOx in this group, but the facility plans to use controlled staged combustion (i.e. limiting oxygen present in certain temperature ranges) to minimize the formation of NOx.

With the exception of Charging (EU05, EU06), which has no NOx emissions, the same assumptions and emission factor sources that were used to calculate CO from this group are used for calculating NOx emissions. The Coking (EU07) and Emergency Stacks/Lids testing (EU10) emission factors for NOx are based on the emission limit at the similar facility Haverhill North Coal Company (Haverhill), located in Franklin Furnace, Ohio. Calculations for NOx emissions due to Pushing (EU08) are based on AP-42, Chapter 12.2, Coke Production. Emission factors for the Natural Gas Lances/Spargers (EU11) are from AP-42, Chapter1.4, Natural Gas Combustion. Since all the calculation assumptions will be verified through testing, the Division finds them acceptable for use in calculating the potential to emit for Group II.

All Stationary Internal Combustion Engine (EU24 through EU29) NOx emissions are calculated using AP-42, Chapter 3.3, Gasoline and Diesel Industrial Engines emission factors.

Comment [JC7]: Used values from 40 CFR 60, Subpart IIII in application.

NOx PSD Analysis

Based on the accepted emission factors and calculations, the total emissions of ~~864.24~~692.9 tpy of NOx exceed the PSD significant emission rate of 40 tpy for this pollutant. Therefore, SunCoke is required to perform a BACT analysis for NOx. See section **5. F**, below, for a discussion of the BACT for NOx.

Lead (Pb)

For this project, Pb emissions are possible from all Group II Coking activities. Coal Charging (EU05, EU06), Coking (EU07), Coke Pushing (EU08), Quench Tower (EU09), and Emergency Stacks/Lids (EU10), and the ~~Natural Gas Lances/Spargers (EU11)~~ are all sources of small amounts of Pb emissions. Since Pb is emitted as a particle, it is generally controlled by the same methods used for controlling all forms of particulate. Therefore, the traveling hood and baghouse mounted on the Pushing/Charging machine controls the Pb from Charging. The baghouse on the main stack controls Pb emissions from coking, while the flat push hot car is equipped with an onboard hood and multicyclone for minimizing PM which also reduces lead from Pushing. The Quench Tower baffles help control Pb emissions from this unit. No controls on the Emergency Stacks/Lids are possible, but, as mentioned before, no actual emissions are expected due to continual use of the induced draft fan at the main stack. For conservatism, however, emissions based on testing times, without induced draft fan operation, are included for this point (EU10).

Emission factors for lead from Coal Charging have been taken from AP-42, Chapter 12.2, Coke Production, Table 12.2-21. Since Pb is a PSD pollutant with a 0.6 tpy threshold, SESS added an additional 20 percent to the emission factor from the table as a conservative measure. Coking and the Emergency Stacks/Lid lead emission calculations are based on a GECC stack test from May of 2010.

Calculations for lead emissions due to Pushing (EU08) use the emission factor from AP-42, Chapter 12.2, Coke Production, Table 12.2-10. As with the Coal Charging factor, a 20 percent buffer has been added as a conservative measure.

The Quench Tower (EU09) calculation for Pb emissions uses data from Haverhill with a 20 percent increase as a buffer for conservatism. Finally, the Pb emission factors used for the Natural Gas Lances/Spargers are from the AP-42 Chapter 1.4, Natural Gas Combustion.

Lead PSD Analysis

Based on the accepted emission factors and calculations, the total emissions of ~~0.0114~~0.22 tpy of Pb do not exceed the PSD significant emission rate of 0.6 tpy for this pollutant. No BACT analysis is required for this pollutant.

Sulfuric Acid Mist (H_2SO_4)

For this project, the formation of SO_3 as a small percentage of the Sulfur Oxides (See SO_2, above) is expected. For emissions calculations, SESS has assumed that all SO_3 is emitted as H_2SO_4.

Of the **Group II** equipment, only Coking (EU07), Pushing (EU08), and Emergency Stacks/Lids (EU10) emit any H_2SO_4. Sulfuric acid mist from coking is controlled through the use of the CDS and baghouse at the main stack, while operation of the induced draft fan prevents emission of the acid gas during emergency stacks/lids testing. Control of these emissions for both the emergency stacks/lids and pushing is achieved through limiting the sulfur content of the coal processed.

For the calculations, coking emissions of H_2SO_4 have been based on data from the Haverhill facility. Emissions from the other two sources are based on an assumption that SO_3 is emitted as a fraction (around 6 percent) of the sulfur oxides emitted at each point. Since the SO_3 is assumed to be emitted as H_2SO_4, the calculations for this pollutant for Pushing and Emergency Stacks/Lids have been based on 6 percent of the SO_2 emissions. The Division finds the calculations acceptable.

H_2SO_4 PSD Analysis

Based on the accepted emission factors and calculations, the total emissions of 33.39 tpy of H_2SO_4 exceed the PSD significant emission rate of 7 tpy for this pollutant. Therefore, SunCoke is required to perform a BACT analysis for H_2SO_4. See section **5. E**, below, for a discussion of the BACT for H_2SO_4.

Green House Gases (GHGs)

In the original application, SESS stated that the GHGs emitted by this project will be Carbon Dioxide (CO_2) and small amounts of Methane (CH_4) and Nitrous Oxide (N_2O). This is due to the controlled combustion used in heat recovery coke ovens and minimal sources of fluorides. In a response to a U.S. EPA inquiry asking for additional information about potential GHGs, SESS stated that there is no stack test/emissions data for GHGs other than CO_2 from their other heat recovery oven facilities. However, SESS went on to say that existing stack tests for VOCs (methane plus other compounds) show very small amounts present (0.05 to 0.12 ppm) as compared with the average CO_2 background concentration. There is also no data available on N_2O emissions from the coking process, but based on data from combustion sources, the N_2O levels are expected to be of the same magnitude as methane and are therefore negligible. No detectable emissions of hydrofluorocarbons, sulfur hexafluoride, and perfluorocarbons are expected. This is due to the fact that the fluorinated gases are not used in or generated by the heat-recovery coking cycle and related processes.

The potential mass emissions of the three expected gases, CO_2, CH_4 and N_2O, have been determined, as outlined above, and multiplied by the gas-specific GWP to establish the total GHGs [CO2(e)]. This method for determining the CO2(e) is the standard per U.S. EPA Guidance and is therefore acceptable.

CO_2 is the major GHG expected from the heat recovery Group II coking process due to the air control exerted over the combustion-like process. For this project, virtually all the CO_2 emissions are from coking with approximately 1 percent from Pushing. For conservative purposes, SESS added emissions of CO_2 from Charging. Operational control of air input, temperature, and work practices during coking are the only active controls used to reduce GHGs for Group II. GHGs are also reduced passively through the use of design specifics that make the project more energy efficient. No significant quantities of GHGs are expected to be emitted from Charging (EU05, EU06), Pushing (EU08), or Quenching (EU09). However, SESS supplied calculations for GHGs due to pushing to comply with the U.S. EPA requirement for reporting and have conservatively assumed that GHGs from charging would be the same as for pushing.

There are also some CO_2, CH_4, and N_2O emissions from the use of natural gas in the Natural Gas Lances/Spargers (EU11), as well as from all of the stationary internal combustion engines due to the use of diesel fuel. Work practices, design choice, and/or fuel and operational limits are the only controls for GHG emissions from these units.

No other emission units are expected to produce GHGs since they are primarily material handling and processing (without combustion) and fugitive emissions from vehicles.

Emissions of CO_2 due to the coking process have been estimated by SESS based on the operating conditions that would produce the maximum CO_2 emissions. CO_2 due to Pushing (and therefore charging) is estimated as outlined in 40 CFR 98.173(c) (Note: from Subpart Q, *Iron and Steel Production*). SESS also estimated emissions of GHGs from the Emergency Stacks/ Lids based on a conservative assumption that a fraction of the CO_2 due to coking could be emitted during lid testing.

For the Natural Gas Lances, emission factors for CO_2, CH_4, and N_2O have been taken from the 40 CFR 98, Subpart C, GENERAL STATIONARY FUEL COMBUSTION SOURCES. The same Subpart was used in estimating all GHGs from the diesel engines. The current global warming potentials found in 40 CFR 98, Subpart A, have been used in estimating the CO2(e).

The Division finds the assumptions made and the calculations submitted for GHGs acceptable.

Green House Gases PSD Analysis

Based on the accepted emission factors and calculations, the total emissions (mass) of ~~980,400~~ 1,374,000 tpy of GHGs exceed the PSD significant emission rate of 75,000 tpy for this pollutant. Therefore, SunCoke is required to perform a BACT analysis for the equipment emitting GHGs. See section **5. G**, below, for a discussion of the BACT for GHGs.

Toxic and Hazardous Air Pollutants

Toxic and Hazardous Air Pollutants are those pollutants that are known or suspected to cause cancer or other serious health effects, such as reproductive effects or birth defects, or adverse environmental effects. In addition to the PSD emissions (which includes the toxic air pollutant H_2SO_4), the facility also analyzed emissions of mercury (Hg) and hydrochloric acid (HCl).

Though Hg and HCl are not PSD pollutants, the SESS application discusses the equipment sources of these two pollutants, controls (if any) and provides emission calculations.

Mercury may be emitted in one of three forms in this project: Particulate, Oxidized, and elemental. Particulate mercury may be captured/removed through devices used for all forms of PM control. Oxidized mercury is better captured/removed by wet flue gas desulfurization and/or dry scrubber systems. Elemental mercury may be marginally reduced through the use of dry scrubbers.

Mercury is emitted during charging (EU05, EU06), Coking (EU07) and the Emergency Stacks/Lids (EU10), and the emission factors used in calculations for each source are based in AP-42, Chapter 12.2, Coke Production.

Coking (EU07) and the Emergency Stacks/Lids (EU10) are sources of HCl. Calculations for HCl due to coking are based on the maximum content of chlorine found in the coal blend planned for use in the ovens. Again, emissions from the Emergency Stacks/Lids is based on the same emission factor as that for coking and the operational limitations of the monthly testing, but is an overestimate due to the use of the induced draft fan at the main stack. The installation of the circulating dry scrubber followed by a baghouse filter as planned for control of SO_2 is expected to remove 95 percent of the HCl produced from coking.

See section **5. H**, below, for a discussion of the control analysis included in the application for these two HAPs.

5. BACT ANALYSIS

The PSD permitting program is designed to ensure that economic growth occurs in a manner consistent with the preservation of existing clean air resources. That is, it requires that new or modified pollutant sources do not endanger public health and welfare, or deteriorate air quality in areas of special natural, scenic or historical value. The PSD program also allows for public participation in the decision making process. [401 KAR 57:017]

The Commonwealth of Kentucky implements a PSD program through 401 KAR 51:017. As part of this regulation, "a new major stationary source shall apply BACT for each regulated NSR pollutant for which the source has the potential to emit in significant amounts." BACT, which stands for Best Available Control Technology, represents the lowest amount of emissions that can be achieved by a particular industrial process. BACT determines what will be the permitted standard (or maximum allowable emissions) for a particular pollutant for a particular project or emission source. What constitutes BACT is based upon a case-by-case decision that considers energy, environmental and economic impact. BACT can be add-on control equipment or modification of the production processes or methods to reduce emissions or emission standard. BACT may also be a design, equipment, work practice or operational standard if setting an emissions standard is not practical.

Since the SESS project will emit more than 100 tpy for each of the PM "types", SO_2, NOx, and CO, it is required to perform BACT on the pollutants that are emitted in quantities that exceed established thresholds. For SESS, the pollutants requiring BACT analysis are PM, PM_{10}, $PM_{2.5}$, CO, VOCs, SO_2, H_2SO_4, NOx, and GHGs (see Section 4.0 Emissions, Table 1 above, for the actual emission levels and thresholds exceeded).

SESS conducted a BACT analysis for each pollutant with the potential to be emitted in excess of the PSD significant emission rate for their proposed project in accordance with the *"Top-Down" Best Available Control Technology Guidance Document* outlined in the 1990 draft U.S. EPA *New Source Review Workshop Manual*, which outlines steps for conducting a top-down BACT analysis. The steps SESS followed are:

(1) Identify available control possibilities for each PSD pollutant based on source knowledge and previous regulatory decisions for identical and similar sources;
(2) Reject inappropriate and technically infeasible control options;
(3) Rank feasible alternatives in descending order of control effectiveness;
(4) Evaluate the most effective controls and weigh the economic, energy and environmental impacts of each; and
(5) Select BACT.

A top-down BACT analysis for each PSD significant pollutant was included in the SESS application.

The Division reviewed the information submitted by SESS along with information available in RBLC and made BACT determinations for all the pollutants subject to PSD review. The Division performed BACT analysis for PM, PM_{10}, $PM_{2.5}$, CO, VOCs, SO_2, H_2SO_4, NOx, and GHGs.
A summary of the BACT analyses and Division decisions is outlined, below.

A. BACT for PM, PM_{10}, and $PM_{2.5}$

For this project, SESS conducted a BACT analysis for PM, PM_{10} and $PM_{2.5}$, but since the same control technologies and practices that reduce the emissions of PM_{10} and $PM_{2.5}$ also reduce PM, all three "types" of particulate matter were addressed together.

<u>Coking (EU07)</u>

Decision: Consistent with the BACT evaluation conducted and submitted by the applicant, the Division determines that the use of a circulating dry scrubber/baghouse filter at the main stack for coking constitutes BACT for PM, PM_{10} and $PM_{2.5}$ for this equipment. The permit establishes limits for this equipment for PM, PM_{10} and $PM_{2.5}$ and requires testing, monitoring, and recordkeeping to ensure compliance those limits.

SESS conducted a search of U.S. EPA's RACT/BACT Clearinghouse database, a record of emission control equipment currently used by various industries and those approved as BACT, to identify possible controls for PM, PM_{10}, and $PM_{2.5}$ from heat recovery coking ovens. The search revealed that only the three existing SunCoke facilities (Haverhill in Ohio, Gateway in Illinois, and Middletown in Ohio) and the proposed FDS Coke (Ohio) and NUCOR Steel facilities (Louisiana) are listed as heat recovery coke oven facilities. Construction of the coking portion of the latter two have not begun as of draft of the SESS Kentucky permit.

SESS also considered the types of control systems used with coal-fired utility boiler as similar, but not identical, to heat recovery coking ovens but determined that differences in the flue gas characteristics such as low fly ash and high acid gases made direct comparison impossible. Because of this, SESS concentrated their analysis on the technology available for heat recovery coke ovens, only.

SESS also identified design differences between the existing SunCoke facilities and the proposed FDS and NUCOR facilities. The RBLC database lists the use of compacted (stamped) coal at NUCOR as part of the BACT for limiting filterable PM during coking and charging. This method requires the installation of equipment for blending, mixing, crushing, and compacting the coal. The FDS facility also proposed using compacted (stamped) coal.

Consistent with the BACT evaluation conducted and submitted by the applicant, the Division determines that the use of a baghouse filter (used in conjunction with a circulating dry scrubber (CDS) for control of SO_2. (See BACT for SO_2, Coking (EU07), below) constitutes BACT for PM, PM_{10}, and $PM_{2.5}$ for this equipment. The permit establishes PM, PM_{10}, and $PM_{2.5}$ limits, in both concentration (units of gr/dscf) and total of emissions (units of tpy). The permit also requires initial testing and a subsequent performance test, monitoring, and recordkeeping for those PM, PM_{10}, and $PM_{2.5}$ limits.

SESS conducted a search of U.S. EPA's RACT/BACT/LAER Clearinghouse database, a record of emission control equipment currently used by the coking industry, and other literature to identify possible controls for PM, PM_{10}, and $PM_{2.5}$ from heat recovery coking ovens. SESS identified five possible devices for the control of the types of PM from coking: fabric filter (baghouse), electrostatic precipitator (dry and wet), high energy wet scrubber, low energy wet scrubber, and mechanical collector (e.g. multicyclone). SESS then presented a review of the different possible technologies, discussed the technical feasibility of each one and the relative control efficiencies.

SESS stated that the fabric filter (baghouse) is the typical control device used for the control of $PM/PM_{10}/PM_{2.5}$ emissions in heat recovery coking. This type of equipment has been widely used for the control of particulates in coal combustion industries since the early 1970s. The baghouse consists of a series of bags (filters), contained in a shell structure, through which the process gas is passed. Baghouses function based on the fact that particles are larger than gas molecules. When a particulate-laden gas is passed through a membrane (fabric filter), the particulate is capture on the filter while the clean gas passes through. Fabric filters, and the materials from which they are made, can be chosen to effectively clean particulates based on the sizes, shapes, and textures of the particulate expected. Baghouses also have cleaning devices, such as jet pulsing, that cause collected dust to fall into dust hoppers at the bottom of the shell structure. The particulate removal efficiency of a baghouse can be as high as 99.9 percent. The use of a baghouse for this project is technically feasible.

Electrostatic precipitation is another technology often used in coal combustion industries. Dry electrostatic precipitators (ESPs) are used in coal-fired sources have demonstrated cleaning efficiencies of greater than 99 percent for fine and coarse particles. A wet ESP operates similarly to the dry ESP for removing PM from a gas stream, but the collecting surface is cleaned by water. Wet ESP has increased water usage, and increased power requirements due to the need for wastewater treatment. These control devices are technically feasible for use with the heat recovery coking process. Either type of ESP is also not as efficient in removing the smallest particles ($PM_{2.5}$) as a fabric filter.

For wet scrubbers, the process gas stream is either sprayed with a liquid or forced into contact with a liquid in order to impact and remove particles entrained in the gas. The particles are captured in liquid droplets that are then collected from the gas stream in a mist eliminator. The resulting liquid is then treated to remove the particles and recycled or discharged. Wet scrubbers are feasible for use with heat recovery coking, but have lower removal efficiencies that either the ESP or the baghouse.

Mechanical collectors (e.g. multicyclones) work on the principal of inertial separation. The collectors use a rapid change in air direction and the property of inertia to separate mass (particulate) from the process gas stream. This type of control is often used when there is a high concentration of coarse particulate. A multicylcone is a feasible control, but has a lower collection efficiency (about 70 percent), over the range of possible particulate sizes, than any of the other possible control technologies except the low-energy wet scrubber.

SESS also analyzed the PM/PM_{10}/$PM_{2.5}$ control candidates in light of the need for a control system combination that also controls SO_2 emissions. SESS briefly examined both dry scrubbing and wet scrubbing for control of SO_2 and concluded that dry scrubbing offers the best control solution due to the extra waste streams and energy requirements of the wet scrubber system. SESS went on to state that use of a dry scrubber for SO_2 in combination with a final filtering from a baghouse or ESP, provides better PM control than wet scrubbing. SESS also said that a baghouse provides better control of fines ($PM_{2.5}$) than other options. A more thorough discussion of the SO_2 control technologies and applicability to the coking process is contained in section **D. BACT for SO_2**, below.

By efficiency rankings either the baghouse or the ESP would be the top choice for controlling the particulate emissions due to coking (EU07). However, a fabric filter would have an edge over ESPs for the control of $PM_{2.5}$. Fabric filters are more effective in controlling fine particulates than ESPs because fabric filters can address particulate penetration concerns with designs involving appropriate materials and gas-to-cloth ratios. This method of control is preferable for fine particulates when compared to collection and particulate penetration issues affecting ESPs such as back corona, dust re-entrainment, and dust sneakage (EPA-452/R-97-001, pp. 5.2-5 – 5.3-6). Therefore, the baghouse is the BACT selection for PM/PM_{10}/$PM_{2.5}$ control for coking (EU07).

The Division concurs with the selection of a CDS/baghouse for this emission unit. The Division also establishes BACT limits of 0.005gr/dscf, and 57.51 tpy for PM (filterable); 0.011 gr/dscf and 126.49 tpy for PM_{10}; and 0.0085 gr/dscf and 97.76 tpy for $PM_{2.5}$ for coking. These limits are comparable or more stringent than other heat recovery coke batteries in the RBLC Database.

Initial compliance for the SESS facility is through stack testing, continuous compliance is demonstrated through a subsequent performance test during the term of the permit, and there are monitoring and recordkeeping requirements for all types of PM for this emissions unit. Finally, the Compliance Assurance Monitoring (CAM) plan requires monitoring the baghouse for both pressure drop and bag leaks.

Coal Charging East and West (EU05, EU06)

Decision: Consistent with the BACT evaluation conducted and submitted by the applicant, the Division determines that the use of a travelling hood and baghouse filter combination onboard the pusher/charger machine constitutes BACT for PM, PM_{10} and $PM_{2.5}$ for this equipment. The permit establishes limits for this equipment for PM, PM_{10} and $PM_{2.5}$ and requires testing, monitoring, and recordkeeping to ensure compliance with those limits.

Charging occurs when a pusher/charger machine travels along the outside of a bank of ovens. Air flows into the negative-pressure oven through the open door and virtually all emissions are captured and sent through the sole flues and common tunnel as the machine places the crushed coal in the oven. However, as the ram retracts over a 1-minute period, some of the emissions could escape as fugitives. Therefore, a capture device and an emission control are necessary to minimize fugitive emissions of PM.

SESS proposes an onboard travelling hood and baghouse as BACT for each of these two emission units. In the SunCoke battery design, the baghouse must travel with the pusher/chargers due to the length of track they must travel to service either the east or west bank of ovens. The RACT/BACT/LAER database shows that this combination is used in all existing SunCoke Energy facilities. As discussed under Coking (EU07), above, the stamped coal technology of Nucor and FDS is not applicable to the oven battery charger design of the SESS facility.

Since baghouses were identified as the top control device for $PM/PM_{10}/PM_{2.5}$ in the previous section on coking, the Division finds the selection of an onboard travelling hood and baghouse acceptable as BACT for this emissions unit for $PM/PM_{10}/PM_{2.5}$. The Division also establishes BACT limits of 0.0081 lb/ton dry coal for PM, 0.012 lb/ton dry coal for PM_{10} and 0.012 lb/ton dry coal for $PM_{2.5}$. These are comparable to the BACT limits established for Middletown and Haverhill.

The permit requires that the SESS facility perform compliance testing of the pusher/charger baghouse outlet for $PM/PM_{10}/PM_{2.5}$ and demonstrate continuous compliance through meeting the PM emission compliance requirements of 40 CFR 63, Subpart L, *National Emission Standards for Coke Oven Batteries* and through daily visible emissions observations, also in accordance with Subpart L. The permit also contains monitoring and recordkeeping requirements for all types of PM for this emissions unit.

Coke Pushing (EU08)

Decision: Consistent with the BACT evaluation conducted and submitted by the applicant, the Division determines that the use of a travelling hood and multicyclone combination onboard the flat car constitutes BACT for PM, PM_{10} and $PM_{2.5}$ for this equipment. The permit establishes limits for this equipment for PM, PM_{10} and $PM_{2.5}$ and requires testing, monitoring, and recordkeeping to ensure compliance with those limits.

With flat car pushing, the bed of coke is pushed from the oven, intact, onto a flat, mobile platform (car) that travels to the quench tower. Unlike traditional pushing, where the coke bed falls down into a hot car and breaks apart, flat pushing does not create a large particulate plume. However, there are still some PM emissions so that the flat car is equipped with a hood that encloses the top and sides of the coke bed. Air circulates into the open ends of the hood and is pulled, by fan, through the top of the hood into a control device. The hood and control travel with the flat car.

Because the coke bed is hot (approximately 2,000°F) and moves, the hood and control device must be able to withstand extreme temperature and the physical constraints imposed by the design of the pusher/charger, coking and quench systems (between the oven banks). That is, heat-resistant materials would be necessary to withstand the temperature and the control/hood system must be small enough to pass below the ducting that transports process gasses to the HRSGs and fit in the narrow confines of a rail car.

In the application, SESS identified several possible controls for PM control during pushing and discussed the technical feasibility and the relative effectiveness of possible controls, including belt-sealed ducts, fabric filters (baghouses), electrostatic precipitators, wet scrubbers, and mechanical collectors (Multicyclones). Except Multicyclones rest of the controls are technically infeasible.

Multicyclones are efficient when treating large gas volumes with several small cyclones being placed in parallel. High temperatures and temperature excursions are not an issue for this type of device, and materials can be chosen to resist the effects of moisture. Since the cyclones can be designed to be small, travelling under the ductwork of the heat recovery coke facility design is also not a problem. An onboard multicyclone is therefore a feasible option for flat car pushing.

The onboard multicyclone, in combination with a mobile hood will control PM and PM_{10} emissions by a 90 percent or greater efficiency. Multicyclones are less effective for $PM_{2.5}$, with about an 81 percent control efficiency.

Since the onboard multicylcone/mobile hood is identified as the only option for PM/PM_{10}/$PM_{2.5}$ control during flat car pushing, the Division determines that the selection is BACT for this emissions unit. The Division also establishes BACT limits of 0.04 lb/ton of coke for PM, 0.06 lb/ton of coke for PM_{10} and 0.06 lb/ton of coke for $PM_{2.5}$.

The permit requires that the SESS facility perform initial compliance testing of the flat car pushing multicyclone outlet for PM/PM_{10}/$PM_{2.5}$ and demonstrate continuous compliance through meeting the PM emission compliance requirements of 40 CFR 63, Subpart CCCCC, *National Emission Standards for Hazardous Air Pollutants for Coke Ovens: Pushing Quenching, and Battery Stacks.* The permit also contains monitoring and recordkeeping requirements for all types of PM for this emissions unit.

Coke Crushing and Screening (EU15)

Decision: Consistent with the BACT evaluation conducted and submitted by the applicant, the Division determines that the use of a baghouse filter in combination with partial and full enclosures of the coke crushing and screening operation in a building, constitutes BACT for PM, PM_{10} and $PM_{2.5}$ for this equipment. The permit establishes limits for this equipment for PM, PM_{10} and $PM_{2.5}$ and requires testing, monitoring, and recordkeeping to ensure compliance with those limits.

The coke crushing operation occurs within a building and breaks the coke product into pieces for use in furnaces. The coke is not pulverized. Since fabric filters (baghouses) have already been ranked as the top $PM/PM_{10}/PM_{2.5}$ control device [see Coking (EU07), above], a baghouse is chosen as BACT for this equipment.

Since the fabric filter control is identified as the best option for $PM/PM_{10}/PM_{2.5}$ control during coke crushing and screening, the Division finds the selection acceptable as BACT for this emissions unit. The Division also establishes BACT limits of 0.005 gr/dscf and 9.39 tpy for PM, 0.005 gr/dscf and 9.39 tpy for PM_{10} and 0.003 gr/dscf and 5.63 tpy for $PM_{2.5}$. These are comparable or more restrictive than the BACT limits established for all heat recovery coking facilities in the RBLC database.

The permit requires that the SESS facility perform initial compliance testing of baghouse outlet for $PM/PM_{10}/PM_{2.5}$ and demonstrate continuous compliance through a second compliance test during the term of the permit. The permit also contains requirements for monitoring the pressure drop across the baghouse on a daily basis and recording any instance of readings outside the established normal range and corrective actions taken.

Emergency Stacks/Lids (EU10)

Decision: The Division determines that limiting the amount of time each stack lid is open on a twelve-month rolling total basis and requiring the operation of the induced draft fan at the main stacks constitutes BACT for PM, PM_{10} and $PM_{2.5}$ this equipment.

Because the facility has redundant HRSGs and main stack control equipment, the emergency stacks/lids are only open during monthly testing or during an actual emergency. No bypass during maintenance is allowed.

For conservative purposes, SESS estimated emissions of pollutants during monthly stack lid testing, but the use of the induced draft fans at the main stacks downstream of this equipment will prevent any emissions from the emergency stacks/lids themselves. Therefore, operation of the induced draft fan at the main stack will prevent emissions during lid testing. The actual pollutants produced during coking at the time of stack lid testing will exit the main stacks and are accounted for under the calculations for Coking (EU07).

The Division establishes BACT limits of 0.63 tpy for PM, 0.63 tpy for PM_{10} and 0.63 tpy for $PM_{2.5}$ and also requires that each lid be open no more than 30 minutes per month (6 hours per year). No other heat recovery coking facilities use this arrangement of emergency stacks/lids with redundant equipment, so the RBLC database contains no BACT listings for such equipment.

The permit requires that the SESS facility demonstrate initial and continuous compliance for $PM/PM_{10}/PM_{2.5}$ through tracking the amount of time the emergency stacks/lids are open and ensuring the operation of the induced draft fan during emergency stacks/lids testing. Finally, visible emission observations of the emergency stacks during lid testing are required to ensure there are no emissions and correction requirement if visible emissions are observed. Monitoring and recordkeeping requirements are included.

Natural Gas Lances/Spargers (EU11)

Decision: The Division determines that the use of natural gas, rather than an alternate fuel, and limiting the usage of the equipment constitutes BACT for PM, PM_{10} and $PM_{2.5}$ for EU11.

The natural gas lances/spargers are used to boost heat in the ovens and afterburner tunnel and may be used to augment heat going to the HRSGs if there is a need for extra power production.

No add-on controls are feasible for this equipment, but the use of natural gas produces less particulate emissions during combustion than would the use of an alternate fuel such as diesel or no. 2 fuel oil. Also, by limiting the natural gas throughput to the EU11 equipment, particulate emissions, as well as emissions of all other PSD significant pollutants, will be minimized.

Since no possible controls for $PM/PM_{10}/PM_{2.5}$ have been identified for the natural gas lances/spargers, the Division finds the selection of operational limits acceptable as BACT. The permit establishes a limit of 800 MMscf/yr natural gas usage based on a twelve-month rolling total. Monitoring and recordkeeping requirements are also included.

Group II-G Coking Process Start-Up

Decision: Consistent with a BACT evaluation, the Division determines that limiting the amount of coal that may be charged to each oven and requiring the beginning CDS/BH operation as soon as possible (a permit time limit) after all the ovens have been initially loaded with coal constitutes BACT for the facility for $PM/PM_{10}/PM_{2.5}$ during start-up.

Start-up is a one-time, extraordinary event for the facility during which equipment is heated and cured, oven bricks are expanded to full size and downstream control equipment is seasoned and brought on-line. During start-up, temporary natural gas burners are used at each oven to begin the heating, dry-out and curing of the silica bricks and cast refractory materials in the ovens, crossover tunnel, HRSG header and emergency stacks. Start-up occurs one bank of 60 ovens at a time and can occur only once.

No RBLC entries for start-up for $PM/PM_{10}/PM_{2.5}$ were identified. Since start-up brings the facility control equipment on-line, no add-on controls are feasible.

The best means identified for limiting all PSD emissions during start-up is to expedite (shorten) the start-up process and limit the amount of coal charged to the ovens during start-up. SESS has proposed to expedite start-up and bring the equipment controls online as quickly as possible in a safe manner. The application, and subsequent submittals, states SESS will complete the start-up in 90 days or less.

Based on the analysis provided in the application, and in subsequent documents, the Division establishes BACT for $PM/PM_{10}/PM_{2.5}$ during start-up to be a set time limit for beginning operation of the CDS/BH associated with the coke oven battery waste gas exhaust of 40 days after all the ovens have been initially loaded with coal. Also, the Division sets a limit on the amount of coal charged to each oven to a maximum of 42.5 tons per 48-hr cycle until start-up is complete. The permit also includes monitoring and recordkeeping requirements to ensure that the BACT requirements for limiting emissions of $PM/PM_{10}/PM_{2.5}$ are being met.

Group V: Storage Silos (EU 20, EU21, EU22)

Decision: The Division determines that the use of bin vent filters that meet a minimum specification of 99 percent control constitutes BACT for PM, PM_{10} and $PM_{2.5}$ for EU20, EU21, and EU22.

For this project, the bulk materials Lime, Hydrated Lime and Flue Gas Desulfurization ash are pneumatically conveyed into a dedicated silo. As the material drops into the silo interior, dust laden air is displaced and must exit the silo. The air is vented through a bin vent. Bin vents are small baghouses that have fabric or cartridge filters and are compact designs meant to be installed on a silo. They are configured such that as the bags are cleaned, the collected dust drops back into the silo. Since they are a type of baghouse, as discussed, above, the filters remove 99 percent of PM, PM_{10} and $PM_{2.5}$ before displaced air is vented to atmosphere.

Since bin vent filters are standard for many material handling applications and fabric filters (baghouses) have already been identified as the top candidate for $PM/PM_{10}/PM_{2.5}$ control, the Division finds selection of bin vent filters acceptable as BACT.

The permit establishes BACT limits for all three types of PM for each of the silos. For the Lime Silo (EU20), the limits are ~~0.234~~0.2354 tpy for PM, 0.2354 tpy for PM_{10}, and 0.0589 tpy for $PM_{2.5}$. For the Hydrated Lime Storage Silo (EU21), the limits are 0.311 for PM, 0.311 tpy for PM_{10}, and 0.078 tpy for $PM_{2.5}$. For the Flue Gas Desulfurization Ash Storage Silo, the limits are 0.00052 tpy for PM, 0.000245 tpy for PM_{10}, and 0.0000371 tpy for $PM_{2.5}$. Compliance is demonstrated by requiring the installation of bin vent filters that meet the specification of 99 percent control. Continuous compliance is demonstrated by requiring installation of bin vent filters.

Additionally, the permit sets an opacity limit of 10 percent for all three silos. Initial and continuous compliance is demonstrated by the performance of visible emissions test on a daily basis.

Group VII: Internal Combustion Engines: Diesel Engines > 500 and = or < 800 HP: Cranes [Crane E-Barge Unloading (EU28) and Crane F-Coal Pile (EU29)]

Decision: The Division determines that restricting the hours of operation of the Diesel Engines used in the Cranes to no more that 16 hours per day, based on a monthly average, shall constitute BACT for PM, PM_{10} and $PM_{2.5}$ for EU28, and EU29.

Both crane engines are affected sources under the federal NSPS and have no controls. For the purposes of PSD, the permit establishes an operating limit of 16 hours a day for each crane. The permit also includes monitoring and recordkeeping for compliance demonstration.

B. BACT for Fugitive PM, PM_{10}, and $PM_{2.5}$

Based on the definition discussed above, the fugitive particulate emissions for this project will come from the Group I Coal Transfer equipment, including Coal Unloading (EU01), Coal Storage Piles (EU02), Coal Crushing (EU03), and Coal Handling (EU04); Group II Coking Processes and Equipment, including Coal Charging East (EU05) and West (EU06), and the Quench Tower (EU09); Group III Coke Transfer equipment, including Coke Handling (EU13), Coke Storage Pile (EU14), and the Coke Breeze Bunker (EU16); Group IV Roadway Emissions, including Paved Roads (EU17), and Unpaved Roads (EU18); and the Cooling Tower (EU19).

Since fugitives can not "reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening", add on control equipment is generally infeasible for most of these emission points. However, work practice control measures can be used to reduce the emissions of fugitive particulates. The application submitted presented a table listing BACT measures that would be taken for most of the sources of fugitive PM, PM_{10}, and $PM_{2.5}$.

Decision: After considering the available control measures and the RBLC database, the Division establishes the following BACT determinations:

Table 2

Emissions Unit	BACT Control Of Fugitives
Coal Unloading (EU01)	Unloaded from Barge at River. No Control feasible.
Coal Storage Piles (EU02) Radial Stacker Load-in: Crane/Loader Load Out: Coal Storage Piles:	 Good Engineering Practice drop height, wetting of material Good Engineering Practice drop height, wetting of material Wetting of material and/or berm, wind screen
Coal Crushing (EU03)	Building enclosure and wetting of materials.
Coal Handling (EU04) Storage bins, transfer points)	Enclosure (except where prohibited due to moving equipment) and wetting of material
Coke Handling (EU13)	Full or partial enclosure (except where prohibited for safety concerns) and wetting of material
Coke Storage Pile (EU14) Radial Stacker Load-in: Loader Load Out:	 Good Engineering Practice drop height, wetting of material No control

Coal Storage Piles:	No control
Coke Breeze Bunker (EU16)	Partial enclosure and wetting of material
Paved Roads (EU17)	Flushing of paved surfaces
Unpaved Roads (EU18)	Chemical suppressants, wetting of material
Cooling Tower (EU19)	Design to 0.0005% drift

The permit requires that the Group I Coal Transfer equipment incorporate the BACT control technologies/techniques and demonstrate compliance through inclusion of the BACT controls in the fugitive coal dust control plan required under 40 CFR 60.254. The permit requires that the permittee certify that design elements listed as BACT have been implemented in the final construction of the facility. Deviations in the design require prior approval before construction.

The Quench Tower (EU09)

Decision: Consistent with the BACT evaluation conducted and submitted by the applicant, the Division determines that the use of wet quenching with a baffled tower and limited total dissolved solids (TDS) in the quench water constitutes BACT for PM, PM_{10} and $PM_{2.5}$ for this equipment. The permit establishes limits for this equipment for PM, PM_{10} and $PM_{2.5}$ and requires testing, monitoring, and recordkeeping to ensure compliance with those limits.

SESS identified and analyzed the particulate emissions characteristics of four different processes that might be used to cool coke beds: Wet Quenching, Dry Quenching, Coke Stabilization Quenching (CSQ) and Low Emission Quench Tower (LEQT).

In the process of wet quenching, the hot loaf of coke would travel down the rail line between the oven banks to the end of the battery where the coke is transferred to a quench car which travels into the quench tower. In the tower, the coke is deluged to cool it. Evaporated water travels up through the tower and specially designed baffles (use of different spacing and shapes and cleaning methods) control the particulates before the plume emits in to the atmosphere. Once cool, the coke would be transferred to the coke handling equipment.

Wet quenching is the most common cooling technique used in the coke industry and is feasible for use with the SESS. Control efficiencies are dependent on baffle design and TDS content in water.

Dry Quenching starts with lifting the 2,000°F coke about 100 feet into the air and dumping it into the top of a stationary vessel tower. Dropping the coke through a tower would not only break up the coke but produce more fines and would adversely affect the emissions and also the yield and quality of the coke SESS produced. This method is eliminated based on projected lower control efficiency compared to wet method.

CSQ is a type of modified wet quenching in which the coke is quenched from above and below the coke mass. This technology can break the coke into small pieces and increase the fine particulate. It is used with byproduct oven coking where coke is dropped into the quench car and is already broken-up. SESS states that this is incompatible with the flat push process used in their heat recovery coking design.

The LEQT, currently being installed at two byproduct coking facilities, is a modified CSQ system. It has a similar tower and baffle design as CSQ, but does not include the bottom quenching. SESS states that the technology has been designed for use with facilities that tumble loose coke into a quench car rather than with a flat push design, but could theoretically be adapted for use. However, SESS also states that since the design has not been demonstrated, yet, and the vendor is not willing to provide performance guarantees, is ruled out as technically infeasible.

Because of the flat push design of the SESS coking system, only the Wet Quench Tower and the LEQT were considered to be theoretically feasible. LEQT has not been demonstrated yet and no test data of performance was found at the time of permit draft. The wet quench tower is chosen as BACT due to its proven compatibility with the flat push design of the SESS heat recovery coking system.

In addition, SESS is using an advanced baffle design in the quench tower that includes a twist in the baffle to increase impact area and therefore increase particulate removal. Based on the design and particle size distribution discussed in "Final Report, Final Report, Coke Quench Tower Modeling Results," Wayne T. Davis, August 17, 2003, SESS reports that the baffle design changes will result in an overall removal of 77 percent for PM~~, PM_{10} and $PM_{2.5}$~~.

Comment [JC8]: Did not assume increased removal of PM10 or PM2.5 with baffle design.

Finally, the amount of dissolved solids in the quench water will be controlled to also minimize particulate emissions.

The Division establishes BACT limits of 0.103 lb/ton of wet coal for PM, 0.044 lb/ton of wet coal for PM_{10}, and 0.027 lb/ton of wet coal for $PM_{2.5}$ and also requires that the TDS of the quench water be limited to 1,100 mg/L.

The permit requires water testing and calculations to demonstrate initial and continuous compliance with the BACT emission limits. The permit also includes monitoring and recordkeeping requirements.

C. BACT for CO and VOC

CO and VOC are produced as products of incomplete combustion, and the approach to controlling each of these pollutants is similar. Therefore, the CO and VOC have BACT analyses are considered together.

Coking (EU07)

Decision: Consistent with the BACT evaluation conducted and submitted by the applicant, the Division determines that the use of combustion optimization for coking activities constitutes BACT for CO and VOCs for Coking (EU07). The permit establishes limits for this equipment for CO and VOCs and requires testing, monitoring, and recordkeeping to ensure compliance with those limits.

SESS conducted a search of U.S. EPA's RACT/BACT Clearinghouse database and industry literature to identify possible controls for CO and VOC from heat recovery coking ovens. They also examined the database and literature for controls for ~~coil~~coal-fired boilers. The search revealed that no add-on controls for CO and/or VOC are currently used. Only good combustion practices (also called staged combustion, and combustion optimization) are listed and used to minimize CO and VOC emissions from heat recovery coking and coal facilities.

Technologies that control CO and VOCs in other applications were also considered. Catalytic oxidation, a post-combustion control option, is designed to oxidize CO and VOCs in the presence of a catalyst. Because catalysts are easily poisoned by PM and SO_2, this technology would need to be installed downstream of the controls for these two pollutants. At that point in the facility, the temperature of the process gas would be too low for the catalyst to work, so the gas would require reheating, resulting in the emission of additional pollutants. Thermal Oxidation raises the temperature of the material (gas in this case) to an auto-ignition temperature to complete combustion of the gas. Since one of the goals in a heat recovery coke plant is complete combustion, and liberation of all available heat, a thermal oxidation device would be redundant with little benefit.

Good combustion practices are part of the design in heat recovery coking facilities. Operation of the coking process with various stages where oxygen content can be manipulated, allows for the complete combustion of the volatiles released. This is one of the goals of this type of facility in that complete combustion of the gases releases all available heat for use in energy generation (at the HRSGs). This naturally produces low emissions of CO and VOCs. Heat recovery batteries are also operated at negative pressure which minimizes the escape of any volatiles. Based on the *Fact Sheet for Thermal Incinerator* (EPA-452/F-03-022), and system combustion temperatures of 1,600°F to 2,400°F, the destruction of CO and VOCs is expected to be in the > 98 percent range due to the effort for complete combustion.

The Division establishes BACT limits of 0.19 lb/ton of wet coal for CO and 0.04 lb/ton of wet coal for VOC for the Coking (EU07). The initial compliance demonstration is through testing for these pollutants and continuous compliance is demonstrated by observing the annual limit on crushed wet coal throughput of 1,226,400 tpy. The permit also includes coal throughput monitoring and recordkeeping requirements.

Coal Charging East and West (EU05, EU06)

Decision: Consistent with the BACT evaluation conducted and submitted by the applicant, the Division determines that the use of work practices for charging activities constitutes BACT for CO and VOCs for Coal Charging East and West (EU05, EU06). The permit establishes limits for this equipment for CO and VOCs and requires testing, monitoring, and recordkeeping to ensure compliance with those limits.

The coke oven battery is designed to maintain negative pressure to prevent emissions, however, during the charging process CO and VOC may escape the oven as the ram is retracted. The pusher/charger machine will be equipped with an onboard hood and baghouse for the control of $PM/PM_{10}/PM_{2.5}$, but the baghouse does not provide any control of CO or VOC.

A check of the RBLC database and industry literature did not identify any add-on controls for minimizing these pollutants during charging. Catalytic and Thermal oxidation, discussed above under Coking (EU07), would not be practical or even possible as ride-along control technologies. Also, for the reasons discussed under $PM/PM_{10}/PM_{2.5}$, Coal Charging East and West (EU05, EU06), above, stationary controls attached to the moving hood are not feasible.

Because the heat recovery ovens operate under negative pressure, most of the charging emissions are contained within the oven. Therefore, the Division accepts selection of the proposed design of the heat recovery ovens (negative pressure) as BACT for CO and VOC for charging.

The Division establishes BACT limits of ~~0.0020~~0.0028 lb/ton of ~~dry~~wet coal for CO and 0.0023 lb/ton of ~~dry~~wet coal for VOC for the Coal Charging East and West (EU05, EU06). Initial compliance with the limit is demonstrated through testing while continuous compliance realized through certification of the negative pressure oven design implementation. The permit also includes monitoring and recordkeeping requirements to ensure that the emission limits are being met.

Coke Pushing (EU08)

Decision: Consistent with the BACT evaluation conducted and submitted by the applicant, the Division determines that the use of work practices that minimize all pollutants constitutes BACT for CO and VOCs for this equipment. The permit establishes limits for this equipment for CO and VOCs and requires testing, monitoring, and recordkeeping for those limits to ensure compliance with those limits.

In the heat recovery process, the operator can ensure that the coal bed has undergone complete carbonization and all volatiles have been released within the negative pressure oven, before pushing. When the carbonization to coke has been completed, all the volatiles have been released and the operator will be able to look through the oven window on one side of the oven and see the door on the other end. This ensures a minimal amount of CO and VOC will be emitted when the coke bed is pushed.

The RBLC database and industry literature list work practices as the only control for CO and VOC for existing and/or proposed heat recovery coking facilities. No add-on controls for minimizing these pollutants during pushing were identified. Catalytic and Thermal oxidation, discussed above under Coking (EU07), would not be practical or even possible as ride-along control technologies. Also, the length of the oven batteries makes the use of such equipment as stationary controls attached to a travelling duct on the onboard hood, infeasible.

Work practices that reduce emission of pollutants, such as visible inspection of the coke bed prior to pushing, are required under the applicable federal MACT, 40 CFR 63, Subpart CCCCC *National Emission Standards for Hazardous Air Pollutants for Coke Ovens: Pushing, Quenching, and Battery Stacks*.

The Division establishes BACT limits of 0.063 lb/ton of wet coal for CO and 0.02 lb/ton of wet coal for VOC for the Coke Pushing (EU08). In the permit, the initial compliance demonstration is through testing for these pollutants and continuous compliance is demonstrated by observing the annual limit on crushed wet coal throughput of 1,226,400 tpy and limit on coke production of 867,4~~7~~47 tpy. The permit also includes coal throughput and coke production monitoring and recordkeeping requirements.

Group II-G Coking Process Start-Up

Decision: The Division determines that limiting the amount of coal that may be charged to each oven constitutes BACT for the facility for CO and VOC during start-up.

Please see above discussion under the BACT analysis for $PM/PM_{10}/PM_{2.5}$ for other operating limitations.

Based on the analysis provided in the application, and in subsequent documents, the Division establishes BACT for CO and VOC during start-up to be limiting the amount of coal charged to each oven to a maximum of 42.5 tons for 48-hr cycle until start-up is complete. The permit also includes monitoring and recordkeeping requirements to ensure that the BACT requirements for limiting emissions of CO and VOC are being met.

D. BACT for SO_2

About half of the sulfur in the coal charged to the heat recovery coking ovens is released during carbonization. Most is released as SO_2 while a small portion (about 6 percent) is released as SO_3. This section analyzes controls for SO_2 only. The next section discusses control of SO_3.

Coking (EU07)

Decision: Consistent with the BACT evaluation conducted and submitted by the applicant, the Division determines that the use of a circulating dry scrubber (CDS) and the baghouse (already chosen for $PM/PM_{10}/PM_{2.5}$ BACT) in a combination designed to reduce emissions by up to 96 percent, and limiting the sulfur content of coal used to no more than 1.3 percent during operation, constitutes BACT for SO_2 for this equipment. The permit establishes limits for this equipment for SO_2 and requires testing, monitoring, and recordkeeping to ensure compliance with those.

SESS conducted a search of the RBLC database and industry literature to identify possible controls technologies for SO_2 due to coking for heat recovery coking facilities. They also examined air pollution control systems for coal-fired utilities, which could theoretically be used, but determined the differences in the processes and the flue gas characteristics prevent a direct comparison of performance.

The pre-combustion control of limiting sulfur content in the coal used was identified and proposed for use with this facility. Approximately half of the sulfur content of the charged coal remains in the coke after carbonization. The sulfur released during the coking process combines with oxygen to form SO_2, with about 6 percent becoming SO_3 (See discussion of H_2SO_4, below). By restricting the sulfur content of the purchased coal, the amount of sulfur oxides formed is restricted as well. Based on the current and projected coal market availabilities, SESS proposed 1.3 percent coal sulfur content in combination with an add-on control designed for up to 96 percent efficiency. The sulfur content limit is comparable to that at the existing SunCoke facilities.

Post-combustion controls, that would treat the cooled flue gases on the discharge side of the HRSGs before being released through the main stack, were identified and analyzed for feasibility and control effectiveness. These four post-combustion controls are: Circulating Dry Scrubber, Lime injection and spray dryer absorber, Wet Scrubber, and Limestone injection.

The circulating dry scrubber (CDS), as discussed in the application, covers a class of controls that bring sulfur-laden flue gases in contact with a reagent. The sulfur combines with the reagent to form particles that are easily removed by a baghouse or other PM control technology. The system is called a dry system, even though some water is used, because it does not produce liquid waste. In the CDS ~~in specific,~~ flue gas is introduced into the bottom of an adsorber where the hydrated lime (reagent) is circulating vertically (fluidized). Water can be sprayed into the circulating bed of reagent. The SO_2 from the flue gas reacts with the water and lime to form a mixture of $CaSO_3$ and $CaSO_4$. The desulfurized gas enters the baghouse (chosen as BACT for PM removal, above) where the particles are removed and fed back into the fluidized bed. The process is relatively easy to maintain and typically has an efficiency > 95 percent removal of SO_2. It has additional benefits of removing other acids such as HCl and SO_3/H_2SO_4 (Bönsel, Tobias, and Rolf Graf, *Operating Experience of Circulating Fluidized Bed Scrubbing Technology in Utility Size Power Plants and Refineries*. PowerGen Europe, Vienna, Austria).

In a Lime Injection and Spray Dryer Absorber (SDA), calcium hydroxide slurry is used in a spray dryer tower. It is injected into the flue gas stream where the droplets react with SO_2. The liquid evaporates and produces a dry product that is collected at the bottom of the tower. The product may be circulated back into the process or used for other applications. It is very similar to the CDS, but the SDA has a slightly lower removal efficiency of 92 percent for SO_2 (Sargent & Lundy, LLC, *Flue Gas Desulfurization Technology Evaluation: Dry Lime vs. Wet Limestone FGD*. Project Number 11311-001, Chicago, IL, March 2007, p. 15).

The Wet Scrubber (WS) uses a more liquid slurry (approximately 10 percent lime or limestone in water) to treat the flue gas stream. The WS systems are designed for efficiencies of >95 percent removal of SO_2, but are more complex, require a larger footprint, use more energy than the CDS, and produce a waste requiring disposal. In addition, this type of system may cause ionic mercury to become mercury vapor (DOE 2008, *An Update on DOE/NETL's Mercury Control Technology Field Testing Program*), making collection difficult *(Srivastava et. al.,* "Preliminary Estimates of Performance and Cost of Mercury Control Technology Applications on Electric Utility Boilers." *Journal of the Air & Waste Management Association 51 (2001): 1461)*, and it has less ability to remove acid mists than other SO_2 control systems ("Flue Gas Desulfurization Technology Evaluation, Dry Lime vs. Wet Limestone FGD", *National Lime Association*, Sargent and Lundy, 2007).

Limestone Injection (LI) is used with coal boilers. A sorbent (lime, limestone, or dolomite) is injected into the combustion gases above the combustion zone through special ports. The sorbent decomposes and reacts with the SO_2 in the gas. The resultant $CaSO_4$, unreacted sorbent, and fly ash are then removed at a particulate control device. LI is not considered technically feasible for use with this project because this process does not provide sufficient suspended dwell time to react with the sulfur in the gas resulting in less control.

- Since CDS and WS have similar high SO_2 removal efficiencies, SESS performed an economic, energy and environmental impacts assessment of each technology. They also analyzed economic impacts utilizing the U.S. Department of Energy (DOE) cost model software program for power plants (Integrated Environmental Control Model developed by NETL) and U.S. EPA's Integrated Planning Model (IPM) Base Case v 4.10 to verify the resulting cost estimate.

Table 3

SO_2 CONTROL SCENARIO	COST EFFECTIVENESS ($/TON SO_2 CONTROLLED)
WET SCRUBBER	$2,141
CIRCULATING DRY SCRUBBER	$1,600

Assuming that the CDS provides a 96 percent removal of SO_2 and the Wet Scrubber could provide a 98 percent removal, SESS demonstrated that the incremental cost for the additional SO_2 removal is $28,079 per ton. The Division concluded that the cost per extra ton of controlled SO_2 is not reasonable for the reduction achieved.

Due to the higher environmental impact, energy use and capital costs of the Wet Scrubber system, the Division finds selection of the Circulating Dry Scrubber, in combination with Baghouse already selected for $PM/PM_{10}/PM_{2.5}$ control, acceptable as BACT for SO_2 removal for Coking (EU07).

The permit establishes a BACT limit for coal sulfur content of 1.3 percent by weight. Compliance is through monthly testing of a composite sample.

The permit also establishes BACT limits for SO_2 from Coking (EU07) of 0.96 lb/ton of wet coal and 134 lb/hr. Initial compliance is established by stack test, with the CEMs providing for continuous compliance. The permit also includes monitoring and recordkeeping requirements to ensure that the emission limits are being met.

Coal Charging East and West (EU05, EU06) and Coke Pushing (EU08)

Decision: Consistent with the BACT evaluation conducted and submitted by the applicant, the Division determines that limiting the sulfur content of coal used to no more than 1.3 percent during operation, constitutes BACT for SO_2 for this equipment. The permit establishes limits for these emission units for SO_2 and requires testing, monitoring, and recordkeeping to ensure compliance with those limits.

In considering possible SO_2 controls for both charging and/or pushing, the issues of the mobility, size restrictions, and the length of the oven battery, as discussed above, make add-on controls infeasible. Also, SO_2 emission is dilute and intermittent from the mobile machinery. Lower-sulfur coal was the only BACT option identified by SESS for this equipment for SO_2.
Based on the analysis provided with the application and in subsequent documents, the Division accepts the limit of 1.3 percent sulfur by weight for the coal as BACT for this equipment. The Division establishes BACT emission limits of 0.0003 lb/ton ~~dry~~wet coal for Charging and 0.06 lb/ton wet coal for pushing. The permit also includes monitoring and recordkeeping requirements.

Group II-G Coking Process Start-Up

Decision: The Division determines that limiting the sulfur content of coal used to no more than 1.1 percent during start-up, constitutes BACT for SO_2 for the facility.

Please see above discussion under the BACT analysis for $PM/PM_{10}/PM_{2.5}$ for other operating limits established to reduce the start up emissions.

Based on the analysis provided in the application, and in subsequent documents, the Division accepts the limit of 1.1 percent sulfur by weight for the coal as BACT for the facility during start-up. The permit requires that the coal sulfur content be checked based on a weekly basis, using composite sampling.

E. Sulfuric Acid Mist (H_2SO_4)

SO_3 is formed in a small fraction of the sulfur volatilized from the coal during carbonization in the oven. Most of the sulfur, as discussed previously, is emitted as SO_2, while only 6 percent is emitted as SO_3. For conservative purposes, SESS assumed that all of the SO_3 possible is emitted as the PSD pollutant H_2SO_4.

Coking (EU07)

Decision: Consistent with the BACT evaluation conducted and submitted by the applicant for SO_2 removal, the Division determines that the chosen use of a circulating dry scrubber (CDS) and the baghouse (already chosen for $PM/PM_{10}/PM_{2.5}$ BACT) in combination with limiting the sulfur content of coal used to no more than 1.3 percent during operation, constitutes BACT for H_2SO_4 for this Coking (EU07). The permit establishes limits for this equipment for H_2SO_4 and requires testing, monitoring, and recordkeeping to ensure compliance with those limits

The RBLC database has only one heat recovery coking facility with control for H_2SO_4 listed-the SunCoke plant in Middletown, Ohio. That facility uses a lime spray dryer in combination with a fabric filter. Since the controls that remove SO_2 from flue gases also remove H_2SO_4, the control options discussed under BACT for SO_2 for coking are the same. The arguments for and against the various controls are also the same, but with some exceptions. The CDS and lime SDA both have excellent H_2SO_4 removal at around 98 percent. The CDS has an advantage over SDA because it is better at SO_2 removal (96 percent vs. 70 to 95 percent). Also, the wet scrubber, which was considered the other top choice for SO_2 removal, has a much lower removal for sulfuric acid mist at only 25 to 50 percent efficiency. Therefore, the CDS is the top option.

The Division finds selection of the Circulating Dry Scrubber, in combination with Baghouse already selected for $PM/PM_{10}/PM_{2.5}$ control, acceptable as BACT for H_2SO_4 removal for Coking (EU07).

The permit establishes a BACT limit for coal sulfur content of 1.3 percent by weight. Compliance is through monthly testing of a composite sample.

The permit also establishes BACT limits for H_2SO_4 from Coking (EU07) of 6.2 lb/hr and 27 tpy. Initial compliance is established by stack test, with ~~the CEMs~~ monitoring the coal sulfur content providing for continuous compliance. The permit also includes monitoring and recordkeeping requirements to ensure that the emission limits are being met.

Coal Charging East and West (EU05, EU06) and Coke Pushing (EU08)

Decision: Consistent with the BACT evaluation conducted and submitted by the applicant, the Division determines that limiting the sulfur content of coal used to no more than 1.3 percent during operation, constitutes BACT for H_2SO_4 for this equipment. The permit establishes limits for pushing equipment for H_2SO_4 and requires testing, monitoring, and recordkeeping to ensure compliance with those limits.

Please see above discussion under the BACT analysis for $PM/PM_{10}/PM_{2.5}$ for other operating restrictions for adding extra controls.

Group II-G Coking Process Start-Up

Decision: Consistent with a BACT evaluation, the Division determines that limiting the sulfur content of coal used to no more than 1.1 percent during start-up, constitutes BACT for H_2SO_4 for the facility. The permit also limits the amount of coal that may be charged to each oven, and sets a time limit for beginning CDS/BH operation after all the ovens have been initially loaded with coal.

Please see above discussion under the BACT analysis for $PM/PM_{10}/PM_{2.5}$ for other operating limits established to reduce the start up emissions.

No RBLC entries for start-up for H_2SO_4 were identified. Since start-up brings the facility control equipment on-line, no add-on controls are feasible.

F. BACT for Nitrogen Oxides (NOx)

Coking (EU07)

Decision: Consistent with the BACT evaluation conducted and submitted by the applicant, the Division determines that the use of staged combustion constitutes BACT for NOx for this equipment.

The permit establishes limits for this equipment for NOx and requires testing, monitoring, and recordkeeping to ensure compliance with those limits.

SESS conducted a search of U.S. EPA's RBLC database and industry literature to identify possible controls for NOx from heat recovery coking ovens. Some consideration was given to boiler NOx control technologies, too, though applicability to the coking process is questionable. The search revealed that there are two types of controls possible to limit NOx: Combustion controls, which are those controls that limit the formation of NOx during combustion; and Post-combustion controls, which are technologies that remove or destroy NOx in the process gas stream. Controls of each type were identified: staged combustion and low NOx burners (LNBs) are combustion controls and selective non-catalytic reduction (SNCR), selective catalytic reduction (SCR) (various types), and Low Temperature Oxidation with Absorption are post-combustion controls.

In staged combustion, NOx is limited by closely controlling the amount of oxygen present in the combustion chamber at temperatures where NOx formation is likely. Control can also be achieved by suppressing peak temperatures that increase NOx formation. In a heat recovery oven, staged combustion techniques can be used in each of the three combustion regions: the crown, the sole flues and the common tunnel. When the volatilized gases gather in the crown of the oven, oxygen is minimized and NOx formation is curtailed. As the gases are drawn down in the sole flue, they may receive additional air so the temperature is controlled to minimize NOx at this stage. Finally, in the tunnel, air is added and there is more abundant oxygen, but enough air is added to cool the gases below the temperature where thermal NOx (formed from nitrogen in ambient air used for combustion) is formed. This technique is an inherent part of the heat recovery process.

Another combustion control, low NOx burners, is often used with boilers and operates by controlling the oxygen and temperature levels in the burners themselves. This technology is not feasible with heat recovery coking ovens because the coal used is never ignited and there is no external fuel used to heat the ovens except for the limited-use natural gas lances.

Selective Non-catalytic reduction is a post-combustion control where ammonia is injected into specific temperature zones in the upper furnace or connective pass of a boiler. The ammonia reacts with NOx in the process gas to produce nitrogen and water. The SNCR process operates over a narrow temperature range, being most effective over 1,800°F to 2,100°F. Above this range, the ammonia will react with oxygen rather than NOx and may even result in the formation of additional NOx. Below the ideal range, ammonia slip increases, where unreacted ammonia is released to atmosphere or reacts to form ammonium bisulfates (ABS), and downstream fouling of equipment occurs. In the common tunnel of the heat recovery coking design, temperatures vary from 1,800°F to 2,400°F, so the temperature would be in range for some period, but locating the possibly mobile window in the 2,500 ft. tunnel would be difficult and the technology has not been demonstrated in connection with the coke oven design.

Another problem for this technology is that its removal efficiency is not good at lower initial NOx levels. Since the NOx levels for the SESS project will be around 70 ppm initially, SNCR control would only be 25 percent effective for removal of NOx.

Finally, the tendency for ammonia slip would increase the formation of ABS and fouling deposits.

For a heat recovery system, this could cause downstream damage to the HRSGs, increasing maintenance and costs. The SNCR is therefore considered infeasible for use with the SESS facility.

Hot-side selective Catalytic Reduction (HSSCR) is similar to SNCR that involves injecting ammonia into the gases in the presence of a metal-based catalyst. This converts the NOx to elemental nitrogen and water. The catalyst allows for a much lower-temperature operation in the 500°F to 800°F range. This control technology is mostly applied to electric utilities with large industrial boilers where it can be inserted between the economizer and air heater to take advantage of the temperature in that area.

The HRSGs that will be used at SESS are of a smaller and different design than the boiler arrangements used for electric utilities. The economizer in the SESS HRSGS will cool flue gases to 350°F as opposed to the 650°F to 750°F range found in the typical large boiler economizer outlet. The smaller HRSGs do not have large sections where the appropriate temperature range for successful operation of the HSSCR can be found.

Another issue is the selection of an appropriate catalyst. Because the flue gas characteristics of heat recovery process gas are different from those in a coal boiler, the fouling tendencies are not well known. As discussed previously, heat recovery coking oven gas does not contain the light fly ash and can produce stickier particles and components that could poison the catalyst. There is currently no data available to help design the proper catalyst.

As with the SNCR, there is the potential for ammonia slip and the resultant formation of ABS. This sticky substance would foul the downstream HRSGs and is difficult to control. This would increase the maintenance required and the cost. The HSSCR is therefore considered infeasible for use with the SESS facility.

Another NOx control technique that uses a catalyst is Tail-End Selective Catalytic Reduction (TESCR). In this configuration, the selective catalytic reduction reactor is placed downstream of all air pollution control equipment installed on a unit. Because it is in this location, the gas stream from the heat recovery common tunnel would have to be reheated for the TESCR to be effective. ABS would still be created due to ammonia slip and form deposits in the stack. Small amounts of chlorides could form ammonium chloride, which is known to cause stress corrosion cracking. The effect of ammonium chloride on catalyst life and performance is not known. This technology has an unknown technical feasibility because it has never been tried at a heat recovery coke plant.

SESS therefore conducted an economic, energy and environmental impact analysis on TESCR in comparison to staged combustion as a possible NOx control for coking activities. As with SO_2, SESS utilized the U.S. Department of Energy (DOE) cost model software program for power plants (Integrated Environmental Control Model developed by NETL) and U.S. EPA's Integrated Planning Model (IPM) Base Case v 4.10 to verify the resulting cost estimate. Some of the differences identified were as follows:

- The TESCR system could cause the formation of ABS and ammonium chloride and cause fouling, and corrosion in other equipment.

- In comparison to staged combustion, the TESCR will result in increased GHG and ammonia emissions. There will also be an increase in H_2SO_4 due to oxidation of remaining SO_2 in the flue gases as it crosses the catalyst.

- TESCR requires additional energy consumption compared with staged combustion due to the need for reheating of the gases.

Table 4

NO_X CONTROL SCENARIO	COST EFFECTIVENESS ($/TON NO_X CONTROLLED)
TAIL-END SELECTIVE CATALYTIC REDUCTION	$14,074
CONTROLLED COMBUSTION	NOT APPLICABLE. INHERENT IN DESIGN

The Division concluded that the cost per ton of controlled NOx is not reasonable for the reduction achieved.

Low Temperature Oxidation with Absorption (LTO) is a NOx removal system that in injects an oxidizing agent, such as ozone, into the gas stream, to combine with NOx and make it soluble. This makes it easier to scrub NOx out of the gas stream using water or caustic solutions. LTO systems are used in gas streams at temperatures below 300°F. For the SESS project, this technology would need to be downstream from the CDS due to temperature concerns. Two possible LTO systems, to be used in a tail-end configuration, were identified for analysis SESS.

In the Tri-NOx® system, NO is oxidized to NO_2 in the primary stage. The NO_2 is then removed by caustic scrubbing in a second stage. This technology requires a wastewater treatment plant and is designed to complement control systems that already use a caustic scrubber and have a wastewater plant. Tri-NOx® is applied to small to medium sources with high NOx concentration in the process gas (around 1,000 ppm). NOx concentration in the SESS facility will be around 70 ppm. This system is not listed as having been successfully demonstrated in any RBLC determination and is not considered a feasible option for SESS.

In the LoTox® LTO system, ozone is used to oxidize NO to NO_2 and NO_2 to N_2O_5 in a wet adsorber. The N_2O_5 is then converted to nitric acid HNO3 in a scrubber and removed with a caustic solution. This technology has only been demonstrated with small to medium-sized coal boilers with gas flow rates from 150 to 35,000 acfm (EPA-600/R-05/034, *Multipollutant Emission Control Technology Options for Coal-fired Power Plants*, March 2005). In contrast, the SESS flue gas flow rate is up to 450,000 acfm. There are also environmental effects to consider if the technology could be scaled up for a larger gas flow, such as increased need for power for ozone generator, need for oxygen source (pipeline or generator), and the possibility that the ozone injection would cause SO_2 in the flue gas to oxidize to SO_3 and increase emissions of sulfuric acid mist H_2SO_4). This technology is not considered to be technically feasible for the SESS project.

Since no add-on controls were found to be technically feasible for this project, and the LNB combustion control technology is not applicable to heat recovery coke ovens, the Division finds selection of the staged-combustion acceptable as BACT for control of NOx emissions for Coking (EU07).

The permit establishes BACT limits for NOx from Coking (EU07) of 1 lb/ton of wet coal and 613 tpy. The lb/ton of coal processed limit is comparable to the NOx limits found for heat recovery coking facilities in the RBLC database. Initial compliance is through an initial stack test and continuous compliance will be demonstrated through a second stack test during the life of the permit. The permit also includes monitoring and recordkeeping requirements to ensure that the emission limits are being met.

Coal Charging East and West (EU05, EU06) and Coke Pushing (EU08)

Decision: Consistent with the BACT evaluation conducted and submitted by the applicant, the Division determines that the implementing the negative pressure oven design and the use of work practices constitutes BACT for NOx for this equipment. The permit establishes limits for this equipment for NOx and requires testing, monitoring, and recordkeeping to ensure compliance with those limits.

The RBLC database and industry literature identify work practices as the only control for NOx during pushing at existing and proposed heat recovery coking facilities. The database does not list any type of control for NOx during charging, though pollution prevention might be observed through work practices. No add-on controls for minimizing NOx during pushing or charging were identified, either. In addition, the add-on NOx controls, discussed above under Coking (EU07), would not be practical or even possible as ride-along control technologies. Also, the length of the oven batteries makes the use of such equipment as stationary controls attached to a travelling duct on the onboard hood, infeasible.

Work practices that reduce emission of pollutants due to charging, such as closing the oven door promptly after the ram retracts, and observing the doors after charging for emissions, are required under the applicable federal MACT, 40 CFR 63, Subpart L, *National Emission Standards for Coke Oven Batteries.* Work practices that reduce emission of pollutants during pushing, such as visible inspection of the coke bed prior to pushing, are required under the applicable federal MACT, 40 CFR 63, Subpart CCCCC *National Emission Standards for Hazardous Air Pollutants for Coke Ovens: Pushing, Quenching, and Battery Stacks.*

The Division establishes a BACT limit of 0.019 lb/ton of wet coal for NOx for the Coke Pushing (EU08). The emissions of NOx during charging are expected to be minimal and dilute, and no data is currently available to suggest that NOx is emitted in any significant quantity. Setting a limit is therefore not practical. The work practices and measures imposed by the applicable federal MACT are considered to be sufficient to minimize NOx emissions during this activity.

In the permit, the initial compliance demonstration for the pushing NOx BACT limit is through testing for this pollutant and continuous compliance is demonstrated by observing the annual limit on crushed wet coal throughput of 1,226,400 tpy and limit on coke production of 867,4~~7~~47 tpy. The permit also includes coal throughput and coke production monitoring and recordkeeping requirements.

Group II-G Coking Process Start-Up

Decision: The Division determines that limiting the amount of coal that may be charged to each oven constitutes BACT for the facility for NOx during start-up. The permit also requires monitoring, and recordkeeping to ensure that the start-up activities minimize emissions.

Please see above discussion under the BACT analysis for PM/PM_{10}/$PM_{2.5}$ for other operating limits established to reduce the start up emissions.

No RBLC entries for start-up for NOx were identified. Since start-up brings the facility control equipment on-line, no add-on controls are feasible.

G. BACT for Greenhouse Gases (GHGs)

Although GHGs are an aggregate group of six gases, including CO_2, N_2O, CH_4, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, they are treated as a single air pollutant for PSD and BACT purposes. SESS analyzed the methods and technologies for reduction and/or destruction for CO_2, the major GHG pollutant component from heat recovery coking facilities, as applicable for all emitted GHGs at the proposed project.

Coking (EU07)

Decision: Consistent with the BACT evaluation conducted and submitted by the applicant, and additional information provided, the Division determines that BACT for coking requires that the facility design include heat recovery ovens, use of superheated instead of saturated steam with HRSGs which include economizer, evaporator, and superheater sections to optimize conversion of heat to steam, natural circulation, a sliding pressure steam turbine, use of combustion optimization, optimized steam production using a process information management system, and work practices that lower energy consumption. The permit establishes limits for coking for GHGs and requires, monitoring and recordkeeping of coal throughput and certification that the design elements proposed as BACT for GHGs and been implemented in the final construction in order to ensure compliance with those limits.

For heat recovery coking ovens, the volatilization of gases during the carbonization process in the ovens, and the complete combustion of those gases in the sole flues, and afterburner tunnel are responsible for 95 percent or more of the CO_2 that will be produced by the SESS facility.

Since the RBLC database did not contain any CO_2 BACT determinations for metallurgical processes at the time the application was submitted, SESS consulted EPA white papers on GHG control measures for the iron and steel industry, technical papers and studies from the power industry, and the GHG Mitigation Strategies Database (Note: The latter database is no longer in service as of issuance of the draft of the permit).

Two broad categories of possible CO_2 technologies were identified and analyzed for the project (emphasizing coking): energy efficiency measures and carbon capture and sequestration (CCS). For an energy efficiency strategy, energy utilization is minimized at a site (plant-wide) to minimize the CO_2 emitted by the power utilities that supply energy to the site. The CCS is based on the separation and capture of CO_2 from process gases and injecting the CO_2 into a suitable geologic formation for long-term storage.

For energy efficiency measures, the plant design and work practices would be planned to reduce fuel usage (on and off-site), use less polluting fuels, recover heat from waste gases, and use more efficient equipment. A discussion of the various types of measures that could be taken and the feasibility for application to the project was submitted by SESS.

Heat recovery ovens are more energy efficient than by-product ovens by design. The intent is to combust the process gases to generate heat to produce electricity for use on-site or to upload to the public power grid. The site does not have to rely on coal or other fuel-fired power utilities to provide the energy needed on site. In addition, no byproduct treatment plants are required for the heat recovery facilities. In the paper *Available and Emerging Technologies for Reducing Greenhouse Gas emissions from the Iron and Steel Industry* (EPA Office of Air and Radiation, 2010), heat recovery ovens are described as an energy efficient option for coke production. Additionally, the negative pressure design reduces the escape of CH_4 fugitive emissions. SESS stated that in addition to using the heat recovery ovens, energy efficiency would emphasized in other equipment design to lower energy consumption which in turn lowers the CO_2 emissions attributable to the site.

For this project, the heat recovery/power generating equipment will be chosen and/or designed for efficiency and flexibility. Using a design that reduces draft losses to decrease the need for fan power consumption, and utilizing natural circulation over forced fan pump circulation have been selected to reduce the power needs of the HRSGs and boost the benefit of the electricity produced. Additionally, the HRSG design will include larger than average evaporators to reduce pinch temperature (variation between gas temperature to fluid temperature) and fouling. Reducing the variations in the loads increases the efficiency of the HRSGs and minimizing fouling decreases maintenance and washing needs. Also, the steam turbine will be designed for sliding pressure to handle any variance in the steam loads (i.e. it will be more efficient because it can fully extract heat across all of the variations in the cycle). The steam piping circuit for this facility will be shorter than in other SunCoke facilities through the use of a centralized power island. This improves energy efficiency by lowering the heat and pressure losses in the pipes. The SESS design will also use redundancy of key heat recovery and air pollution control equipment to allow for periodic inspection, cleaning, and repair with little if any downtime.

Coal moisture control was also presented in the cited EPA white paper as a possible energy efficiency measure, but was more suited to byproduct coke processes or those that don't seek to recover and utilize the waste heat for energy generation. In this approach, waste heat is used to dry the coal rather than to produce electricity. Dryer coal may reduce the fuel consumption needed to carbonize the bed. It is technically feasible for use with a non-byproduct facility, but the benefits of electricity generation without burning additional fuel outweigh the benefits of controlling coal moisture.

Controlled combustion, designed to maximize heat release, drive toward complete combustion, and minimize pollutants, is an inherent part of heat recovery coke oven design and operation. The work practices at SESS, in combination with sensors in the ovens and damper controls, will utilize programmed heating to optimize the entire coking process to minimize pollutants and maximize release of available heat.

SESS also examined whether an alternative coking approach called the Single Chamber System (SCS) would be feasible or offer advantages. In the SCS, the coking reactors are large vessels with greater height and length, but narrower widths, than the multi-chambered ovens of heat recovery ovens. The SCS reactors are separate process-controlled modules with thinner walls that withstand great pressure. The design improves heat transfer and combustion, and therefore better thermal efficiency, but the design is still under development and has not been demonstrated commercially. The use of this design is not considered feasible for this project.

Finally, under the energy efficiency measures, SESS examined the concept of process information management. By using systems to track the performance of equipment and processes in the facility, the plant operation can be optimized. Process information can track power generation, monitor operation of the HRSGs and other equipment to determine maintenance schedules, and maximize steam production. Scheduled preventative maintenance and rotation of the redundant equipment (HRSGs, some controls, etc.) will reduce down time and ensure equipment operates well and provides good performance. Training programs and good housekeeping programs decrease energy consumption throughout the facility.

The second category of GHG controls involves the separation, capture and storage of the CO_2 emissions. There are three main technology categories proposed for the first step of separation and capture: pre-combustion, oxy-fuel combustion, and post-combustion.

Pre-combustion involves the removal of the CO_2 from a fossil fuel before it is combusted. In this type of system, a fuel is converted to gas through heating with steam and air or oxygen. A gas containing mainly hydrogen and CO is produced. The CO is reacted with steam to produce CO_2 and additional hydrogen. The CO_2 is separated out though physical or chemical adsorption. This process is not feasible for use with coke production because it eliminates the desired product, solid carbon.

Oxy-fuel combustion uses pure oxygen, instead of air, and the resulting combustion yields gas with highly concentrated with CO_2. Available technologies for producing pure oxygen are mostly based on cryogenic separation of oxygen from air. Extreme cooling of air produces liquid oxygen, nitrogen, and argon. The process is energy consuming (i.e. produces GHGs at power utilities), costly, and still in the demonstration phase of research. The process is not feasible for use with coke production because the introduction of oxygen into the oven crown and sole flues would cause overheating (burns hotter). Also, the process would be compromised by air leaking into the negative pressure ovens.

Post-combustion capture involves removing and capturing CO_2 from flue gas prior to release to atmosphere. Included in this category of capture are chemical absorption, physical absorption, calcium cycle separation, cryogenic separation, membrane separation and adsorption. The technologies have not been demonstrated at a coke plant, but are considered theoretically feasible.

Chemical absorption is considered the best option of the post-combustion technologies (Simonds, M., et. al., *A Study of Very Large Scale Post Combustion CO_2 Capture at a Refining & Petrochemical Complex*, 6th International Conference on Green House Gas Control Technologies, Kyoto, 2002). A solvent is used at low partial pressure to separate CO_2 in flue gas. Drawbacks for this include the corrosive nature of the solvent in the presence of oxygen, high solvent degradation rates (highly reactive with SO_2 and NOx) and the energy required for solvent regeneration.

Physical absorption uses a solvent at high pressure and low temperature and is typically used for CO_2 removal from natural gas. The low CO_2 concentration in flue gas makes this process unsuitable for use with heat recovery coking processes. The flue gas would have to be strongly compressed to achieve the reaction and would require significant energy, off-setting any reduction in CO_2 emissions.

Calcium cycle separation is still in the research and testing phase. This technology uses quicklime to yield limestone. The limestone is heated to release CO_2 and produce quicklime, again, for recycling. Performance, cost and commercial viability are not yet established (Mackenzie, A., et. al., *Economics of CO_2 Capture Using the Calcium Cycle with a Pressurized Fluidized Bed Combustor*). This technology is not feasible for use with the heat recovery coking process, yet.

Cryogenic separation is widely used for purification of CO_2 from streams that have high concentration of CO_2. This technology is based on solidifying CO_2 by frosting and separating it out. Low CO_2 concentration in flue gas makes this technology uneconomical for use with the SESS project.

Gas separation membranes may be used to selectively transport gases through the film. This technology is used mainly for CO_2 removal from natural gas at high pressure and high concentrations of CO_2. It is a new technology for this application and has not been optimized for large scale applications (*CO_2 Capture and Storage: A VGB Report on the State of the Art*, VGB Power Tech, 2004). Low concentrations of CO_2 in the flue gas would make this technology uneconomical for use with this project due to high penalties on power generation efficiency.

Adsorption of CO_2 can be accomplished by passing flue gas through a bed of solid material, such as activated carbon. Adsorption requires high compression or multiple separation steps and is not applicable for large-scale operations, yet (VGB Power Tech, 2004). It is not feasible for use with heat recovery coking processes.

Other less developed technologies, including aqueous ammonia wet scrubbing, solid sorbents, metal organic frameworks, enzyme-based systems and ionic liquids, are not mature enough to be commercially available.

Along with separation/capture technologies, the transportation and sequestration of the CO_2 must also be accomplished to truly reduce GHGs. The captured CO_2 must either be reused or liquefied, transported and permanently stored.

Pipelines are the most common method of transporting large amount of CO_2 over long distances. The gas must be compressed under high pressure for pipeline transport, which requires high energy consumption. Water must be eliminated from the pipeline to prevent the formation of corrosive carbonic acid. Booster compressors along the pipeline may be needed to maintain the pressure along the long lengths of transport pipe. Pipelines must also be maintained to prevent CO_2 escape. There are 14 large CO_2 pipelines in the U.S., mostly in the Western states. Smaller CO_2 pipelines connect sources with specific customers. There are no constructed CO_2 pipelines within 500 miles of the SESS site.

Storage options for the CO_2 are under development. These include storage in geological formations, such as exhausted oil fields, saline formations, under ocean liquid storage, solid carbonate storage, and terrestrial sequestration. Globally, only four commercial CCS facilities are sequestering captured CO_2 and monitoring to verify it remains sequestered. Other projects are starting to be funded and developed, but transportation and storage of CO_2 from SESS is not feasible due to lack of pipeline and available storage infrastructure.

Since the separation, capture and sequestration technologies are either not-feasible, negate the energy savings of a heat-recovery coking process, and may be cost prohibitive (*Cost and Performance of Carbon Dioxide Capture from Power Generation Working Paper*, IEA, 2011) the Division finds selection of energy efficiency measures and design acceptable as BACT for control of CO_2 emissions for Coking (EU07).

The permit establishes BACT limits for GHGs [CO2(e)] from Coking (EU07) at 1,299,984 tpy. Initial compliance is through verification of use of proposed energy efficient designs in the final construction and preparation of a GHG work practices plan for reducing energy use on site. Continuous compliance is demonstrated through limiting the coal throughput to 1,226,400 wet tpy on a 12-month rolling total. The permit also includes monitoring, recordkeeping, and reporting requirements to ensure that the emission limits are being met.

Coal Charging East and West (EU05, EU06)

Decision: Consistent with the BACT evaluation conducted and submitted by the applicant, and additional information provided, the Division determines that BACT for charging is the use of heat recovery ovens under negative pressure. The permit establishes limits for charging for GHGs and requires, monitoring and recordkeeping of coal throughput and certification that the design elements proposed as BACT for GHGs and been implemented in the final construction to ensure compliance with those limits.

During charging, most of the emissions are captured and sent to the sole flues and common tunnel because of the negative pressure design of the coke ovens. Some of the charging emissions that escape the ovens are captured by a traveling hood and baghouse. GHG emissions from charging are expected to be negligible (<100 tpy). For conservative purposes, SESS estimated potential GHG emissions to be similar to pushing operations (<10,000 tpy), or less than 1 percent of all GHG emissions.

SESS found no GHG controls for charging in the RBLC database. As discussed under other charging BACT analyses, the use of add-on controls is not feasible. The emissions of GHGs from charging are small and intermittent due to the negative pressure of the ovens.

Because the heat recovery ovens operate under negative pressure, most of the charging emissions are contained within the oven. Therefore, the Division accepts selection of the proposed design of the heat recovery ovens (negative pressure) and limiting the coal throughput as BACT for GHGs.

The permit establishes a BACT limit of 9,811tpy for GHGs, conservatively based on the limit established for pushing. Initial and continuous compliance is monitoring of the coal throughput, certification of the negative pressure oven design, and implementation of a GHG work practices plan. The permit also includes monitoring and recordkeeping requirements to ensure that the emission limits are being met.

Coke Pushing (EU08)

Decision: Consistent with the BACT evaluation conducted and submitted by the applicant, and additional information provided, the Division determines that BACT for pushing is ensuring complete carbonization of coal to coke.

CO_2 will be present in pushing emissions and is expected to represent less than 1 percent of the total CO_2 emitted. The emissions are dilute and intermittent from mobile machinery.

SESS found no add-on GHG controls for pushing in the RBLC database. As discussed under other charging BACT analyses, the use of add-on controls is not feasible. The emissions of GHGs from charging are small and intermittent due to the negative pressure of the ovens.

The permit establishes limits for charging of 9,811tpy for GHGs and requires monitoring and recordkeeping of coal throughput and certification that the design elements proposed as BACT for GHGs and been implemented in the final construction in order to ensure compliance with the limit.

Emergency Stacks/Lids (EU10)

Decision: The Division determines that limiting the amount of time each stack lid is open on a twelve-month rolling total basis and requiring the operation of the induced draft fan at the main stacks constitutes BACT GHGs for this equipment.

Because the facility has redundant HRSGs and main stack control equipment, the emergency stacks/lids are only open during monthly testing or during an actual emergency. No bypass during maintenance is allowed.

For conservative purposes, SESS estimated emissions of pollutants during monthly stack lid testing, but the use of the induced draft fans at the main stacks downstream of this equipment will prevent any emissions from the emergency stacks/lids themselves. Therefore, operation of the induced draft fan at the main stack will prevent emissions during lid testing. The actual pollutants produced during coking at the time of stack lid testing will exit the main stacks and are accounted for under the calculations for Coking (EU07).

The Division establishes a BACT limit of 890 tpy for GHGs [CO2(e)] and also requires that each lid be open no more than 30 minutes per month (6 hours per year). No other heat recovery coking facilities use this arrangement of emergency stacks/lids with redundant equipment, so the RBLC database contains no BACT listings for such equipment.

The permit requires that the SESS facility demonstrate initial and continuous compliance for GHGs [CO2(e)] through tracking the amount of time the emergency stacks/lids are open and ensuring the operation of the induced draft fan during lid testing. Monitoring and recordkeeping requirements are included.

Natural Gas Lances/Spargers (EU11)

Decision: The Division determines that limiting the use of the lances/spargers, constitutes BACT for GHGs [CO2(e)] for EU11.

The natural gas lances/spargers are used to boost heat in the ovens and afterburner tunnel and may be used to augment heat going to the HRSGs if there is a need for extra power production.

No add-on controls are feasible for this equipment, but the emissions from this equipment will exit the main stack with the flue gases. However, as discussed, above, no add-on controls are feasible for the coking processes, either. Since there are no listings for Natural Gas Lances/Spargers for coking facilities in the RBLC database, SESS analyzed the listed control methods for other, non-coking application of natural gas combustion sources. The database lists good combustion practices and energy efficiency measures as BACT for most boilers and heaters. SESS proposed that good combustion practices (i.e. proper utilization of the lances), and an operational limit on the use of the lances would minimize GHGs and constitute BACT.

The Division finds the selection of good combustion practices and operational limits acceptable as BACT and establishes a BACT limit of 48,111tpy of GHGs [CO2(e)]. The permit requires that SESS prepare and maintain a GHG work practices plan and also establishes a limit of 800 MMscf/yr natural gas use based on a twelve-month rolling total. Initial and continuous compliance with the emission limit is demonstrated though monitoring and recordkeeping.

Group II-G Coking Process Start-Up

Decision: Consistent with a BACT evaluation, the Division determines that limiting the amount of coal that may be charged to each oven constitutes BACT for the facility for GHGs [CO2(e)] during start-up. The permit also requires monitoring, and recordkeeping to ensure that the start-up activities minimize emissions.

Please see above discussion under the BACT analysis for $PM/PM_{10}/PM_{2.5}$ for other operating limits established to reduce the start up emissions.

Based on the analysis provided in the application, and in subsequent documents, the Division establishes BACT for GHGs during start-up to be limiting the amount of coal charged to each oven to a maximum of 42.5 tons until start-up is complete. The permit also includes monitoring and recordkeeping requirements to ensure that the BACT requirements for limiting emissions of GHGs are being met.

Emergency Internal Combustion Engines:
Emergency Engine A (EU24), Fire Pump < 600 HP
Emergency Generator B (EU25) <600 HP
Group VI Emergency Generators = or > 600 HP (EU26, EU27)

Decision: The Division determines that good combustion practices and the preparation and implementation of a GHG work practices plan constitutes BACT for GHGs [CO2(e)] for EU24–EU27. Emergency engines are also limited to 100 hours per year operation. The permit establishes a GHG emission limit for the engines and includes the requirement of performing emissions calculations in accordance with 40 CFR 98 and keeping records.

GHG emissions from testing and maintenance of fire pumps and emergency engines are expected to be negligible (< 10 tpy for the fire pump, <100 tpy for the EU25–EU27) and intermittent.

NO GHG controls are technically feasible for any of the engines. The RBLC database lists good combustion and work practices for emergency diesel engines. Emergency engines are limited to less than 100 hours of operation a year for periodic testing.

The Division determines that BACT for all emergency engines is good combustion practices, operational limits, and the preparation and implementation of a GHG work practices plan for all emergency generators/engines. BACT GHG emission limits of 43 tpy for EU24 and EU25 and limits of 350 tpy for EU26 and EU27 are also established. The emissions will be calculated pursuant to 40 CFR 98, Subpart C, *General Stationary Fuel Combustion Sources.* Monitoring of fuel use and operating hours and recordkeeping are required by the permit.

Group VII Diesel Engines >500 and = <800 HP, Cranes E and F (EU28, EU29)

Decision: The Division determines that good combustion practices, limiting operation to 16 hours per day for each engine (on a monthly average) and the preparation and implementation of a GHG work practices plan constitutes BACT for GHGs [CO2(e)] for EU28, and EU29. The permit establishes a GHG emission limit for the engines and includes the requirement of performing emissions calculations in accordance with 40 CFR 98 and keeping records.

Estimated GHG emissions from the use of diesel cranes are expected to be relatively small (<5,500 tpy or <0.5percent of total GHG emissions from the facility), intermittent and potentially from a mobile source.

No coking facility GHG BACT listings were found in the RBLC database, but it does list good combustion and work practices as BACT for diesel crane engines at non-coking facilities. NO add-on GHG controls are technically feasible for any of the engines.

The Division determines that BACT for both crane engines is good combustion practices, limiting operation to 16 hours (each) per day, and the preparation and implementation of a GHG work practices plan for the engines. A BACT GHG emission limit of ~~5,400~~5,430 tpy for EU28 and EU29 is also established. The emissions will be calculated pursuant to 40 CFR 98, Subpart C, *General Stationary Fuel Combustion Sources.* Monitoring of fuel use and operating hours and recordkeeping are required by the permit.

H. Additional Control Analyses

Hydrochloric Acid from Coking and Related Activities

During coking, chlorine in coal becomes HCl, a strong acid that reacts easily with lime-based reagents. Therefore, controls that remove acid gases, such as SO_2, also remove HCl. As discussed under the BACT for SO_2, scrubbers (both CDS and SDA) and dry lime injection would be potential controls for HCl. But, as discussed under the analysis for SO_2 due to Coking (EU07), limestone injection is eliminated due to the potential for contaminating the coke with the sorbent. Both CDS and SDA would control HCl emissions by more than 95 percent, however, since CDS was the most effective for also removing SO_2, H_2SO_4 and $PM_{2.5}$, CDS is the best control option for HCl.

Mercury from Coking and Related Activities

During coking, mercury in the coal volatilizes and converts to mercury vapor. The vapor may then form mercury compounds or be adsorbed into particles in the gas stream. Three types of mercury can result from heating coal: Particulate-bound mercury, oxidized mercury, and elemental mercury. The different types of mercury impact the efficiency of capture for air pollution control devices. Particulate-bound mercury can be captured by most particle control devices, such as baghouses. Oxidized mercury is more readily removed by wet flue gas desulfurization systems or dry scrubbers. Elemental mercury, the most difficult to capture and/or remove, does not respond to many traditional air pollution controls. Dry scrubber can remove some amount of this type of mercury (*Behavior of Mercury in Air Pollution Control Devices on Coal-Fired Utility Boilers,* Constance, 2001).

Activated Carbon Injection (ACI) had the potential to remove additional elemental and oxidized mercury when use in dry scrubbers. This extra control measure was used at the Granite City where operational issues interfered with proper operation of the system. Testing and analysis are underway to determine why the ACI system caused problems, but at this point, ACI is not considered a reliable. Additionally, including ACI at Haverhill increased the cost of mercury removal to approximately $19,000,000/ton of mercury removed (not including equipment, labor, or maintenance) due to the high cost of activated carbon. Because of the cost and operational difficulties, ACI is not considered a feasible application for this facility.

Particulate phase mercury will be removed by any baghouse. Vapor phase will be removed, in a limited amount, by either a spray dryer or wet scrubber. Because of the adverse environmental impacts of the wet scrubber, discussed under SO_2 BACT analysis for Coking (EU07), CDS is chosen as the top control option for vapor phase mercury.

I. BACT SUMMARY

Table 5

Pollutant	Emission Unit	BACT Determination
$PM/PM_{10}/PM_{2.5}$	Coking-main stack (EU07)	CDS/BH or equivalent
	Coal Charging (EU05, EU06)	Onboard, travelling hood with baghouse
	Coke Pushing (EU08)	Onboard, travelling hood with Multicyclone, flat pushing
	Coke Crushing/Screening (EU15)	Enclosure and baghouse
	Emergency Stacks/Lids(EU10)	Time limit for testing, required draft fan operation
	Natural Gas Lances/Spargers (EU11)	Natural gas use limit
	Group II Start-Up	Coal throughput limit, expedite start-up
	Storage Silos (EU20, EU21, EU22)	Bin vent filters with 99% efficiency design
	Crane Diesel Engines (EU29, EU29)	Maximum use of 16 hours per day
Fugitive $PM/PM_{10}/PM_{2.5}$	Coal and Coke Handling/Transfer Units (EU01-EU04, EU13, EU14, EU16)	Full and partial enclosures, wetting of materials, good engineering practice drop heights, berms, wind screens, all as applicable to the individual emission point
	Quench Tower (EU09)	Wet quench, improved baffles, limited TDS
	Paved Roads (EU17)	Flushing paved surfaces
	Unpaved Roads (EU18)	Chemical suppressants, wetting of materials
	Cooling Tower (EU19)	Maximum 0 0005% drift
CO and VOC	Coking (EU07)	Combustion Optimization
	Coal Charging (EU05, EU06)	Negative pressure oven design
	Coke Pushing (EU08)	Work practices
	Group II Start-Up	Limit coal charge each oven during start-up, 40 day time limit to operation of CDS/BH
SO_2	Coking (EU07)	CDS, Design efficiency 96%, Coal sulfur limit 1.3 %
	Coal Charging (EU05, EU06)	Coal sulfur limit of 1.3 %
	Coke Pushing (EU08)	Coal sulfur 1.3%
	Group II Start-Up	Coal sulfur 1.1%, limit coal charge each oven during start-up, 40 day time limit to operation of CDS/BH
H_2SO_4	Coking (EU07)	CDS/BH, Design efficiency 98%, Coal sulfur limit 1.3%
	Coal Charging (EU05, EU06)	Coal sulfur 1.3%
	Coke Pushing (EU08)	Coal sulfur 1.3%
	Group II Start-up	Limit coal charge each oven during start-up, 40 day time limit to operation of CDS/BH
NOx	Coking (EU07)	Staged Combustion
	Coal Charging (EU05, EU06)	Work practices
	Coal Pushing (EU08)	Work practices, coal throughput
	Group II Start-up	Limit of coal charged to each oven
GHGs [CO2(e)]	Coking (EU07)	Facility design elements, combustion optimization, work practices
	Coal Charging (EU05, EU06)	Negative pressure oven design

	Coke Pushing (EU08)	Ensure complete carbonization (Work practices)
	Emergency Stacks/Lids (EU10)	Time limit for testing, required draft fan operation
	Natural Gas Lances/Spargers (EU11)	Natural gas use limit
	Group II Start-up	Limit coal charge each oven during start-up
	Emergency Engines (EU24-EU27)	Good combustion practices, implement GHG work practices plan
	Crane Diesel Engines (EU29, EU29)	Good combustion practices, limit daily hours operation, implement GHG work practices plan

6. AIR QUALITY IMPACT ANALYSIS

1. Modeling Background

Pursuant to 401 KAR 51:017, Section 10, an application for a PSD permit shall contain an analysis of ambient air quality impacts. Total project emissions of Carbon Monoxide (CO), Nitrogen Dioxide (NO_2), Sulfur Dioxide (SO_2), Particulate Matter of 10 microns or smaller (PM_{10}), and Particulate Matter of 2.5 microns or smaller ($PM_{2.5}$) for the proposed SunCoke facility are estimated to exceed the Prevention of Significant Deterioration (PSD) significant emission rates. To comply with the requirements of 401 KAR 51:017, SunCoke submitted an ambient air quality analysis and the modeling application timeline is detailed below.

SunCoke Modeling Application Timeline

Table 6

Date	Action
July 27, 2011	SunCoke submitted Ozone Limiting Method (OLM) request for NO_2 modeling to Region 4 EPA
April 13, 2012	SunCoke submitted modeling protocol for 120 oven facility
April 27, 2012	SunCoke submitted revised OLM request for NO_2 modeling to Region 4 EPA
August 3, 2012	Region 4 EPA conditionally approves OLM request
November 14, 2012	SunCoke responded to EPA comments on OLM request
December 10, 2012	SunCoke submitted PSD/Title V construction/operating permit application.
January 22, 2013	Additional modeling information received- table of modeling files
February 7, 2013	Application and modeling sent to Region 4 EPA
March 19,2013	Division issued a modeling Notice of Deficiency (NOD)
April 12, 2013	SunCoke submitted first response to NOD- Modeling Inputs: narrative and files
April 25, 2013	Division issued an extension to the modeling NOD response
May 9, 2013	SunCoke submitted second response to NOD- Modeling Output; narrative and files
May 23, 2013	SunCoke submitted additional information- Revised tables: SILS, PSD Increment, and NAAQS results: Revised PM_{10} modeling files (replacements)
June 10-11, 2013	SunCoke submitted additional information- Modeling demonstration files (for 5 criteria pollutants)
June 17, 2013	SunCoke submitted Ambient Air Monitoring Waiver request
June 18, 2013	SunCoke submitted additional information- Revisions to Table 6-1a and Table 6-1b
July 25, 2013	Division granted the Ambient Air Monitoring Waiver

July 30, 2013	SunCoke submitted additional information to Region 4 EPA for OLM request
August 5, 2013	Division issued NOD- Modeling
August 8, 2013	Permit application declared complete
August 8, 2013	SunCoke submitted additional information to Region 4 EPA for OLM request
August 12, 2013	Additional modeling information received- Offsite inventory parameters
August 13, 2013	Federal Land Manager received notification of application and initial air modeling files
August 14, 19, 2013 September 3, 24, 30, 2013 October 1-2, 2013 December 9, 2013	Additional modeling information received- Offsite inventory parameters and information
September 6, 2013	Division sent SunCoke emissions inventory system (EIS) report for modeling inventory
September 9, 2013	Additional modeling information received- Significant Impact Area drawings
September 11, 2013	Additional modeling information received- Overlapping Significant Impact Area drawings
October 3, 2013	Additional modeling information received- Revised Significant Impact Area drawings
October 10, 2013	SunCoke submitted response to NOD- Modeling
October 9, 18-20, 2013	Modeling files associated with October 10, 2013 NOD response received
October 24, 2013	Additional modeling information received- PM_{10} 24-hr Maxi files
October 30, 2013	Additional modeling information received- Inventory receptors for Graf Brothers and OSCO New Boston
October 31, 2013	Additional modeling information received- New Boston $PM_{2.5}$ Monitoring Data; PM_{10} annual and 24-hour plot files; SO_2 annual input, output, and plot files (2007 year)
November 5, 2013	Additional modeling information received- Class I plot files and revised VISCREEN runs (closest scenic vista- Shawnee State Park)
November 6, 2013	Additional modeling information received- Explanation for $PM_{2.5}$ 24-hr calculation error
November 12, 2013	SunCoke submitted additional modeling information for NOD- modeling
November 13, 2013	Additional modeling information received- $PM_{2.5}$ 24-hour input, output, plot, and contribution files (5 year averaging); PM_{10} 24-hour input, output files (5 year averaging)
November 19, 2013	Additional modeling information received- Downwash files; Met Data files (AERMET version 12345); NO_2 Season/Hour monitoring background file; SO_2 1-hour contribution file analysis (9th rank, 120 threshold)
November 20, 2013	Additional modeling information received- PM_{10} 24-hour output file (5 year averaging); revised SO_2 1-hour contribution file analysis (15th rank, 80 threshold)
November 21, 2013	Additional modeling information received- Revised NO_2 1-hour modeling demonstration
November 26, 2013	Additional modeling information received- Revised NO_2 Season/Hour monitoring background file; NO_2 1-hour modeling files (error)
December 2, 2013	Additional modeling information received- Revised SO_2 1-hour contribution file analysis (191st rank, 136 threshold)
December 2, 2013	Federal Land Manager approved Class I visibility
December 11, 2013	Additional modeling information received- Correct SO_2 annual input file (2010)

December 14, 2013	Additional modeling information received- $PM_{2.5}$ 24-hour contribution analysis (156th rank, 15.7 threshold), input, output files (5 year averaging)
December 15, 2013	Additional modeling information received- $PM_{2.5}$ 24-hour narrative; Revised $PM_{2.5}$ 24-hour narrative; PM_{10} 24-hour narrative; PM_{10} 24-hour significant receptors for PSD Increment (each separate year submitted)
December 16, 2013	Additional modeling information received- PM_{10} 24-hour PSD Increment significant impact overlap isopleths for project and OSCO New Boston facility (each separate year submitted); PM_{10} 24-hour PSD Increment input, output files (each separate year submitted); PM_{10} 24-hour overlapping impact analysis files (each separate year submitted); PM_{10} 24-hour NAAQS input, output files (each separate year submitted)

In the ambient air impact analysis, SunCoke performed dispersion modeling for CO, NO_2, SO_2, PM_{10}, and $PM_{2.5}$ to demonstrate that emissions of regulated pollutants from the proposed project will not adversely affect air quality levels in the Class II areas surrounding the facility. Using procedures consistent with Appendix W to 40 CFR 51, the modeling was completed using the EPA recommended model AERMOD (version 12345). Representative meteorological data was processed using AERMET (version 12345 and 11059). Using the AERMAP terrain processor (version 11103), receptor elevations were assigned to a gridded set of receptors beginning at the SunCoke boundary extending out to approximately 5 to 10 km, depending on the pollutant and averaging period.

2. Class II Modeling Analysis

The short-term and long-term emission rates of CO (short-term only), NO_2, SO_2, PM_{10}, and $PM_{2.5}$ from the planned SunCoke project were explicitly modeled. These emissions were modeled using input parameters as tabulated in Table 6-1a and Table 6-1b in the October 10, 2013 response to the second modeling Notice of Deficiency and inventory parameters as tabulated in the November 12, 2013 additional dispersion modeling information document. The resulting modeled concentrations, based on submissions from SunCoke, were compared to the significant impact levels (SILs) and significant monitoring concentrations (SMCs) as shown in Table 7. The results show that the modeled CO impacts are below the SILs and are presumed insignificant; thus, no further modeling was completed. For all other pollutant and averaging periods, further cumulative modeling was performed to demonstrate compliance with the PSD increments and national ambient air quality standard (NAAQS) as tabulated in Table 8 and Table 9, respectively.

See Next Page for Table 7

TABLE 7

Modeled Pollutant Concentrations in Comparison with Class II SILs

Pollutant	Averaging Period	Maximum Modeled Concentration (μg/m3)	Form and Year[c]	SIL (μg/m3)	Significant Monitoring Concentration (μg/m3)	Does SunCoke Impact Exceed Threshold?
CO	1-hour	184.8	H1H 2009	2000	-	No
	8-hour	97.6	H1H 2008	500	575	No
NO_2	1-hour	127.3	H1H 5 year average 2007-2011	7.5[a]	-	Yes
	Annual	3.6	H1H 2011	1	14	Yes
SO_2	1-hour	150.1	H1H 5 year average 2007-2011	7.86[a]	-	Yes
	3-hour	107.5	H1H 2010	25	-	Yes
	24-hour	27.8	H1H 2010	5	13	Yes
	Annual	1.95	H1H 2011	1	-	Yes
PM_{10}	24-hour	17.04	H1H 2010	5	10	Yes
	Annual	3.09	H1H 2011	1	-	Yes
$PM_{2.5}$	24-hour	7.87	H1H 2011	1.2[b]	-	Yes
	Annual	1.53	H1H 2011	0.3[b]	-	Yes

[a] Interim SIL
[b] Based on 40 CFR 51:165(b)(2), Interim
[c] H1H refers to the high first high concentration of all receptors modeled for that time period

TABLE 8

Cumulative Modeled Pollutant Concentrations in Comparison with Class II PSD Increments

Pollutant	Averaging Period	Cumulative Modeled Concentration (µg/m3)	Form and Year[a]	Project Contribution to Cumulative Impact greater than PSD Increment (µg/m3)	PSD Increment (µg/m3)	Does SunCoke Impact Cause or Contribute Significantly to a Modeled Violation?
NO_2	1-hour	-	-	-	-	-
	Annual	9.1	Max 2011	-	25	No
SO_2	1-hour	-	-	-	-	-
	3-hour	278	H2H 2007	-	512	No
	24-hour	58.5	H2H 2007	-	91	No
	Annual	2.7	Max 2010	-	20	No
PM_{10}	24-hour	15.0	H2H 2010	-	30	No
	Annual	22.8	Max 2010	<1 (SIL)	17	No
$PM_{2.5}$	24-hour	7.1	H2H 2011	-	9	No
	Annual	1.5	Max 2011	-	4	No

[a] H2H refers to the high second high concentration of all receptors modeled for that time period and Max refers the maximum annual average concentration of all receptors for that time period.

TABLE 9

Cumulative Modeled Pollutant Concentrations in Comparison with Class II NAAQS

Pollutant	Averaging Period	Modeled Concentration	Background Concentration[a]	Cumulative Modeled Concentration Plus Background (µg/m3)	Form and Year[b]	Project Contribution to Cumulative Impact greater than NAAQS (µg/m3)	NAAQS (µg/m3)	Does SunCoke Impact Cause or Contribute Significantly to a Modeled Violation?
NO_2	1-hour	167.6	Season-by-hour values applied in modeling run	167.6	H8H 5 year average 2007-2011	-	188	No
	Annual	9.1	17.32	26 42	Max 2011	-	100	No
SO_2	1-hour	1333.0	60 11	1393.11	H4H 5 year Average 2007-2011	<7.86 (SIL)	196.5	No
	3-hour	277.99	107.5	361.8	H2H 2007	-	1300	No
	24-hour	58.5	27.8	86.3	H2H 2007	-	365	No
	Annual	2.71	3.11	5.82	Max 2010	-	80	No
PM_{10}	24-hour	256.3	35	291 3	H6H Over 5 years 2007-2011	<5 (SIL)	150	No
	Annual	-	-	-	-	-	-	-
$PM_{2.5}$	24-hour	129.2	19 3	148.5	H8H 5 year average 2007-2011	<1.2 (SIL)	35	No
	Annual	8.15	8.93	17.08	Max 5 year average 2007-2011	<0 3 (SIL)	12	No

[a] Background Data Sources.
NO_2 monitoring data source. Ashland, Kentucky monitor (21-019-0017)· 1-hour: season-by-hour background values applied within modeling run using 2008-2010 data; Annual: average of 2008-2010 data
SO_2 monitoring data source New Boston, Ohio monitor (39-145-0013). 1-hour: 2009-2011 data; 3-hr: 2010 data, 24-hr: 2010 data, Annual: 2010 data
PM_{10} monitoring data source New Boston, Ohio monitor (39-145-0013)· 24-hr: 2010
$PM_{2.5}$ monitoring data source Carter County, Kentucky monitor (21-043-0500: 24-hr: 2010-2012 data, Annual· 2010-2012 data
[b] HXH refers to the high X high concentration of all receptors modeled for that time period, where X represents the ranking. Max refers the maximum annual average concentration of all receptors for that time period.

D. Additional Impacts Analysis:

401 KAR 51:017, Section 13 requires that all PSD applicants conduct additional Air Quality Impact Analyses (AQIA) that assesses impacts on soils, vegetation, and visibility caused by the increase in emissions from the new source. A review of potential growth in the community associated with the new source must also be conducted.

IMPACT ON SOILS, VEGETATION, AND VISIBILITY

The National Ambient Air Quality Standards (NAAQS) are designed to protect the health and welfare of residents and the environment, including the effects on soils and vegetation. As discussed in the December 2012 Application and in the response to the second modeling NOD dated October 10, 2013, the emissions resulting from this project do not exceed the secondary NAAQS or EPA Screening Levels. Therefore, no adverse impact to soil or vegetation is expected.

SunCoke submitted VISCREEN modeling to the Division on November 5, 2013, demonstrating the absence of visual impacts at the closest scenic vista, Shawnee State Park located near West Portsmouth, Ohio. Therefore, visibility impacts are also not expected.

GROWTH

As discussed in the December 2012 Application, an impact on air quality due to regional growth attributed to the proposed SunCoke project is projected to be negligible.

OZONE IMPACTS

As discussed in the December 2012 Application, an adverse impact on ambient ozone concentrations due to the proposed project is not expected.

IMPACT ON CLASS I AREAS

Otter Creek Wilderness, WV, located approximately 280 km miles east of the proposed SunCoke facility, is a designated Class I area. The Federal Land Manager does not anticipate adverse impacts of any air quality related values (AQRVs) at Forest Service Class I Areas by the proposed SunCoke project.

Additionally, to demonstrate compliance with the Class I Increment Levels, SunCoke provided the Division with a comparative analysis using the Riverside Generating Company, LLC as a surrogate to their facility. This analysis is described in the additional dispersion modeling information document dated November 12, 2013.

Commonwealth of Kentucky
Division for Air Quality

COMMENTS AND RESPONSE

ON THE STATEMENT OF BASIS

ATTACHMENT 2

SESS Comments on SunCoke Energy South Shore Draft Construction and Operating Permit V-13-007, Plant ID 021-089-00047, Agency Interest No. 105793

Commonwealth of Kentucky
Division for Air Quality
COMMENTS AND RESPONSE
ON THE STATEMENT OF BASIS
ATTACHMENT 2
SunCoke Comments on Draft Air Quality Permit for SunCoke Energy South Shore
Permit No. V-13-007; AI No. 105793

Suggest deleting text shown formatted as ~~strikethrough~~
Suggest inserting text shown formatted as **bold underline**

Citation	Requested Change	Comment
Section B, 3. b.; page 8	**(2) Prepare a written site-specific monitoring plan for a digital opacity compliance system for approval by the Administrator or delegated authority. The plan shall require observations of at least one digital image every 15 seconds for 10-minute periods (during normal operation) every operating day. An approvable monitoring plan must include a demonstration that the occurrences of visible emissions are not in excess of 5 percent of the observation period. For reference purposes in preparing the monitoring plan, see OAQPS "Determination of Visible Emission Opacity from Stationary Sources Using Computer-Based Photographic Analysis Systems." This document is available from the U.S. Environmental Protection Agency (U.S. EPA), Office of Air Quality and Planning Standards, Sector Policies and Programs Division, Measurement Group (D243-02), Research Triangle Park, NC 27711. This document is also available on the Technology Transfer Network (TTN) under Emission Measurement Center Preliminary Methods. The monitoring plan approved by the Administrator or delegated authority shall be implemented by the owner or operator.**	Add text from 40 CFR 60.255(f)(2) in "b"
Section B, 1. e.; page 13	The BACT determination for GHGs [CO2(e)] requires ~~that~~ a negative pressure design of the coking ovens to minimize emission of coke oven gases during charging.	Delete "that"
Section B, 2. b.; page 13	(4) For CO: 0.002**8** lb/ton ~~dry~~ **wet** coal (5) For VOC: 0.0023 lb/ton ~~dry~~ **wet** coal (6) For SO2: 0.0003 lb/ton ~~dry~~ **wet** coal	Omitted digit in CO factor. Emission factors other than PM are per wet ton coal.
Section B, 2. c. (1); page 14	(1) No person shall cause, suffer, allow, or permit any continuous emission into the open air from a control device or stack associated with ~~any affected facility~~ **the pushing/charging machine** which is equal to or greater than ten (10) percent opacity as a six-minute average from the stack. [401 KAR 51:017, BACT Determination]	Clarify specific emission unit this applies to
Section B, 6. b.; page 17	The permittee shall submit certification that the design elements proposed as BACT for the emission unit or process have been implemented in the final construction. Any deviations from the design elements proposed in the application shall be submitted to the Division within ~~30 days~~ **a reasonable time** after the change in design is made and before construction of the changed element.	Any change in design will go through several iterations. It may not be possible to provide this within 30 days.

Citation	Requested Change	Comment
Section B, 2. b. (1); page 21	Continuous compliance with the SO2 emission limit **of 134 lb/hr** shall be demonstrated through use of Continuous Emissions Monitoring. See **4. Specific Monitoring Requirements**, items **h** through **j**, below.	CDS will be designed to meet 134 lb SO_2/hr under all conditions. Revise to match CAM plan.
Section B, 2. b. (1); page 21	**BACT limit of 0.96 lb SO_2/ton wet coal to be demonstrated through performance testing. See 3. Testing Requirements, item d, below.**	Add new requirement. Clarify that BACT limit is to be demonstrated through performance testing.
Section B, 2. b. (1); page 21	Continuous compliance with the H2SO4 emission limits shall be demonstrated through ~~use of Continuous Emissions Monitoring~~ **adherence to the coal sulfur content limit**. See **4. Specific Monitoring Requirements**, item **d** ~~h through j~~, below.	There are no commercially available H_2SO_4 CEMs. However, H_2SO_4 emissions will be limited by coal sulfur content (and controlled by the CDS along with SO_2).
Section B, 3. d.; page 24	Performance tests used to demonstrate compliance with 401 KAR 59:105, Section 4 (SO2) **and 0.96 lb SO_2/ton wet coal** shall be conducted according to the following methods, filed by reference in 401KAR 50:015: Reference Method 6 for Sulfur Dioxide. [401 KAR 59:105, Section 6(2)]	CDS will be designed to meet 0.96 lb SO_2/ton wet coal at normal conditions that create the highest rate of emissions.
Section B, 4. h.; page 25	Continuous emission monitoring systems shall be installed, calibrated, maintained, and operated for measuring the SO2 ~~and H2SO4~~ emissions. The continuous emission monitoring systems shall comply with ~~40 CFR 75, Appendix A~~ **Appendix B of 40 CFR 60**. Pursuant to 40 CFR 64.3(d), the continuous emission monitoring systems shall be used to satisfy CAM requirements for sulfur dioxide, only. [401 KAR 52:020, Section 10]	Delete reference to H_2SO_4 CEM. Use CFR citation that matches CAM plan.
Section B, 4. i.; page 25	Pursuant to 401 KAR 52:020, Section 10, to meet the monitoring requirement for SO2 ~~and H2SO4~~, the permittee shall use continuous emission monitors (CEMs). Excluding the startup and shut down periods, if any 3-hour average sulfur dioxide ~~or sulfuric acid mist~~ value exceeds the standard, the permittee shall, as appropriate, initiate an inspection of the control equipment and/or the CEM systems and make any necessary repairs as soon as practicable.	Delete references to H_2SO_4 CEM.
Section B, 4. j.; page 25	For performance evaluations of the SO2 ~~and H2SO4~~ continuous emission monitoring system as required under 401 KAR 59:005, Section 4(3) and calibration checks as required under 401 KAR 59:005, Section (4), ~~reference methods 6c or 7e~~ **Appendix B of 40 CFR 60** shall be used as applicable as described by 401 KAR 50:015.	Delete reference to H_2SO_4 CEM. Revise CFR reference for CEM performance specifications.
Section B, 6. b.; page 27	Any deviations from the design elements proposed in the application shall be submitted to the Division within ~~30 days~~ **a reasonable time** after the change in design is made and before construction of the changed element.	Any change in design will go through several iterations. It may not be possible to provide this within 30 days.
Section B, 6. d.; page 27	~~Per CAM requirements for the CDS/BH, the permittee must submit summary information on the number, duration and cause (including unknown cause, if applicable) for monitor downtime incidents (other than downtime associated with zero and span or other daily calibration checks, if applicable). [40 CFR 64.9(a)(2)(ii)] Also see permit SECTION D – SOURCE EMISSIONS LIMITATIONS AND TESTING REQUIREMENTS, item 6.~~	Duplicate term

Citation	Requested Change	Comment
Section B, 6. f. (2); page 27	All hourly averages shall be reported for SO2 ~~and H2SO4~~ monitors. The hourly averages shall be made available in the format specified by the Division.	Delete reference to H_2SO_4 CEM
Section B, 6. g.; page 28	Excess emissions of SO2 ~~and/or H2SO4~~ are defined as any three (3) hour period during which the average emissions (arithmetic average of three contiguous one hour periods) exceed the applicable SO2 ~~or H2SO4~~ emission standard~~s~~.	Delete reference to H_2SO_4 CEM
Section B (EU08), Section Title; page 29	**Group II-C Emission Units 08 (EU08) Coke Pushing**	Only one unit, delete "s"
Section B, 3. a.; page 33	**<u>Method 8A – Determination of sulfuric acid vapor or mist and sulfur dioxide emissions from Kraft Recovery Furnaces</u>**	Add alternate H_2SO_4 test method to list of test methods
Section B (EU10), Description ; page 41	**<u>Description</u>:** The 130-foot tall emergency stacks provide natural draft during emergencies (i.e. a major power outage) in order to maintain negative pressure in the ovens. The stacks, covered by ~~clamshell~~ **<u>stack</u>** lids, are open only during the start-up, during emergencies, and for monthly lid functioning tests.	Optimal design for emergency stack lids may not be "clamshell" arrangement.
Section B, 2. (b); page 45	For the natural gas lances **<u>/ spargers</u>**, for GHG [CO2(e)] limits, the permittee shall limit the natural gas used to 800 MMscf/yr. See **1. <u>Operating Limitations</u>**, above, and the corresponding **Compliance Demonstration Method**.	Make description consistent
Section B, 4.; page 45	The permittee shall monitor and record the amount of natural gas consumed by use of the natural gas lances **<u>/ spargers</u>**. See **5. <u>Specific Recordkeeping</u>** Requirements, below.	Make description consistent
Section B, 6. b.; page 55	The permittee shall submit certification that the design elements proposed as BACT for the emission unit or process have been implemented in the final construction. Any deviations from the design elements proposed in the application shall be submitted to the Division within ~~30 days~~ **<u>a reasonable time</u>** after the change in design is made and before construction of the changed element.	Any change in design will go through several iterations. It may not be possible to provide this within 30 days.
Section B, 6. a.; page 61	The permittee shall submit certification that the design elements proposed as BACT for the emission unit or process have been implemented in the final construction. Any deviations from the design elements proposed in the application shall be submitted to the Division within ~~30 days~~ **<u>a reasonable time</u>** after the change in design is made and before construction of the changed element.	Any change in design will go through several iterations. It may not be possible to provide this within 30 days.
Section B, 2. b.; page 64	Compliance with opacity will be determined by visible emissions testing conducted daily~~, in accordance with EPA Method 9~~. See section **3. <u>Testing Requirements</u>, 4. <u>Specific Monitoring Requirements</u>**, item **b** and **5. <u>Specific Recordkeeping Requirements</u>**, items **b**, **c**, and **d**, below.	As specified below in **4. <u>Specific Monitoring Requirements</u> b.**, procedure is daily qualitative visible observation followed by Method 9 determination of opacity if needed.
Section B, 6. a.; page 65	The permittee shall submit certification that the design elements proposed as BACT for the emission unit or process have been implemented in the final construction. Any deviations from the design elements proposed in the application shall be submitted to the Division within ~~30 days~~ **<u>a reasonable time</u>** after the change in design is made and before construction of the changed element.	Any change in design will go through several iterations. It may not be possible to provide this within 30 days.

Citation	Requested Change	Comment
Section B, (EU23), Entire Section; page 66	~~**Emission Unit 23 (EU23) Heat Recovery Steam Generators (HRSGs)**~~	The HRSGs are not emission units. Move all subsections to corresponding subsections under **Emission Unit 07 (EU07) Coking**
Section B, (EU23), Description ; page 66	Size/Rated Capacity: ~~<25 MW~~ **equivalent power from each ≤25 MW**	Clarify that the threshold is ≤25 MW for each HRSG
Section B, 1. ; page 66	To preclude the applicability of 40 CFR 72, Subpart A, Acid Rain Program General Provision, an individual unit (HRSG) shall not supply **more than** 219,000 MWe-hrs ~~or more~~ of actual electric output on an annual basis to any utility power distribution system for sale (on a gross basis).	Revise wording to match CFR
Section B, 4. a. ; page 66	The permittee shall monitor the actual electrical output of each unit on a monthly basis. **If the units are identical, the actual electrical output of each may be determined as the total actual electrical output divided by 3 (the number of units).**	Simplify monitoring if the HRSGs are identical.
Section B, 4. b. ; page 66	The permittee shall monitor the sale of actual electrical output to any utility power distribution system for each unit on a monthly and yearly basis. **If the units are identical, the sale of actual electrical output of each may be determined as the sale of total actual electrical output divided by 3 (the number of units).**	Simplify monitoring if the HRSGs are identical.
Section B, (EU24), Description ; page 68	Planned Model Year: ~~2014~~ **2013** or later	Although the facility construction may start in 2014, 2014 engines may not be available.
Section B, 6. b.; page 73	~~The permittee shall submit engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement to the Division 30 days prior to installation. [401 KAR 52:020, Section 10]~~	Notification not required for emergency engines of this size.
Section B, (EU25), Description ; page 74	**Description:** An emergency stationary diesel-fueled engine for operation ~~of the coke screening equipment~~ **in the screening station area** that will operate a limited number of hours per year (100 hr/yr). It is an affected source under the federal NSPS and has no controls. Unless there is an emergency, the engine will only run for occasional testing.	Unit will be used in emergency situations as needed.
Section B, (EU25), Description ; page 74	Planned Model Year: ~~2014~~ **2013** or later	Although the facility construction may start in 2014, 2014 engines may not be available.
Section B, 1. b.; page 74	If the permittee owns or operates a 2007 model year and later stationary CI internal combustion engine and shall comply with the emission standards specified in 40 CFR ~~60.4204 (b)~~ **60.4202(a)**, the permittee shall comply by purchasing an engine certified to the emission standards in 40 CFR 60.4205(b), as applicable, for the same model year and maximum engine power. The engine shall be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of 40 CFR 60.4211. See **1. Operating Limitations**, item **d**, below. [40 CFR 60.4211(c)]	Citation should be for emergency engines.

Citation	Requested Change	Comment
Section B, 6. b.; page 80	~~The permittee shall submit engine information including make, model, engine family, serial number, model year, maximum engine power, and engine displacement to the Division 30 days prior to installation. [401 KAR 52:020, Section 10]~~	Notification not required for emergency engines of this size.
Section B, (EU26), Description ; page 81	Planned Model Year: ~~2014~~ **2013** or later	Although the facility construction may start in 2014, 2014 engines may not be available.
Section B, (EU27), Description ; page 81	Planned Model Year: ~~2014~~ **2013** or later	Although the facility construction may start in 2014, 2014 engines may not be available.
Section B, 1. b.; page 82	If the permittee owns or operates a 2007 model year and later CI internal combustion engine and shall comply with the emission standards specified in 40 CFR ~~60.4204 (b)~~ **60.4202(a)** or 40 CFR 60.4205 (b), the permittee shall comply by purchasing an engine certified to the emission standards in 40 CFR ~~60.4204 (b)~~, **60.4202(a)** or 40 CFR 60.4205 (b) or (c), as applicable, for the same model year and maximum engine power. The engine shall be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of 40 CFR 60.4211. See **1. Operating Limitations**, item **d**, below. [40 CFR 60.4211 (c)]	Citation should be for emergency engines.
Section B, (EU28), Description ; page 88	Planned Model Year: ~~2014~~ **2013** or later	Although the facility construction may start in 2014, 2014 engines may not be available.
Section B, (EU29), Description ; page 88	Planned Model Year: ~~2014~~ **2013** or later	Although the facility construction may start in 2014, 2014 engines may not be available.
Section B, 1. b.; page 89	If the permittee owns or operates a 2007 model year and later stationary CI internal combustion engine and shall comply with the emission standards specified in 40 CFR 60.4204 (b), the permittee shall comply by purchasing an engine certified to the emission standards in 40 CFR ~~60.4205(b)~~ **60.4201**, as applicable, for the same model year and maximum engine power. The engine shall be installed and configured according to the manufacturer's emission-related specifications, except as permitted in paragraph (g) of 40 CFR 60.4211. See **1. Operating Limitations**, item **c**, below. [40 CFR 60.4211(c)]	Citation should be for non-emergency engines.
Section B, 2. c.; page 91	The following emission limit is established as the BACT emission requirement for EU28 and EU29 (total): [401 KAR 51:017, Section 8(a)] For CO_2: ~~5,400~~ **5,430** tpy	Show one more significant digit
Section B, 3. e.; page 92	The permittee shall conduct three separate test runs for each performance test required in 40 CFR 63 Subpart ZZZZ, as specified in 40 CFR 63.7(e)(3). Each test run shall last at least 1 hour **unless otherwise specified**. [40 CFR 63.6620(d)]	Include missing text from citation.
Section B, 3. f.; page 92	The permittee shall determine compliance with the percent reduction requirement **[if this option is selected]** according to the methods specified in 40 CFR 63.6620(e).	Insert text to clarify that there are other compliance options.

Citation	Requested Change	Comment
Section B, 3. k.; page 93	If the permittee must comply with the emission limitations and operating limitations **[and not using a CEMs]**, the permittee shall conduct subsequent performance tests as specified in Table 3 of 40 CFR 63 Subpart ZZZZ.	Insert text to clarify that there are other compliance options.
Section B, 4. f. (1); page 95	Except for monitor malfunctions, associated repairs, **required performance evaluations,** and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the permittee shall monitor continuously at all times that the stationary RICE is operating.	Include missing text from citation.
Section B, 6. j. (4); page 98	~~If the permittee had a startup, shutdown, or malfunction during the reporting period, the compliance report shall include the information in 40 CFR 63.10(d)(5)(i).~~ **If there is a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction that occurred during the reporting period and that caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with 40 CFR 63.6605(b), including actions taken to correct a malfunction.**	Substitute text from regulation 40 CFR 63:6650(c)(4)
Section D, 1., d.: page 120	Initial and continuous compliance with quenching requirements set forth in 40 CFR 63.7295(a)(1)~~:~~ **(i) or (ii):** (1) Upon initial start-up, when compliance is required under 40 CFR 63.7283, the permittee shall demonstrate continuous compliance with the TDS limit for quenching in 40 CFR 63.7295(a)(1)(i) by meeting the requirements in paragraphs (f)(1) and (2) of 40 CFR 63.7333: [40 CFR 63.7333(f)] (i) Maintaining the TDS content of the water used to quench hot coke at 1,100 mg/L or less; and [40 CFR 63.7333(f)(1)] (ii) Determining the TDS content of the quench water at least weekly according to the requirements in 40 CFR 63.7325(a) and recording the sample results; or [40 CFR 63.7333(f)(2)]**; [or]** (2) Upon initial start-up, the permittee must demonstrate continuous compliance with the constituent limit for quenching in 40 CFR 63.7295(a)(1)(ii) by meeting the requirements...........	Clarify that the facility may choose between the two compliance methods in this section.
Section D, 5. f.; page 130	Pursuant to 40 CFR 63.7333(f)(2), the results of the weekly TDS content of quench water shall be recorded; or pursuant to 40 CFR 63.7333(g)(2), the monthly sum of the constituent concentrations of the quench water shall be recorded if using the procedure in 40 CFR ~~63.7334(e)(3)~~ **63.7325(c)**.	Revise CFR citation
Section D, 5. g.; page 130	Pursuant to 40 CFR 63.7334(e)(2), the permittee shall record quench tower baffle washing, inspection and repair and the ambient temperature on days the baffles are not washed. Additionally, the permittee shall maintain records of makeup water sources pursuant to 40 CFR 63.733~~3~~4(e)(3)	Minor typo in last CFR citation

Commonwealth of Kentucky
Division for Air Quality

COMMENTS AND RESPONSE

ON THE STATEMENT OF BASIS

ATTACHMENT 3

U.S. Environmental Protection Agency Comments on SunCoke Energy South Shore Draft Construction and Operating Permit V-13-007, Plant ID 021-089-00047, Agency Interest No. 105793

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

January 27, 2014

Mr. Sean Alteri
Director
Division for Air Quality
Department for Environmental Protection
200 Fair Oaks Lane, First Floor
Frankfort, Kentucky 40601-1134

Dear Mr. Alteri:

Thank you for sending the draft Prevention of Significant Deterioration (PSD) permit and Statement of Basis (SOB) for the proposed new construction of the SunCoke Energy facility to be located in South Shore, Kentucky. The U.S. Environmental Protection Agency reviewed the draft PSD permit and SOB, which we received on December 22, 2013. Additionally, the EPA reviewed the applicant's response (July 19, 2013) to the EPA's comment letter. The applicant proposes to construct a new coke-making facility using the latest generation of heat recovery coke ovens (120) oriented in two parallel trains. The project also includes coal handling and storage, charging, pushing, and quenching operations, as well as coke handling and storage. The project will produce 831,000 tons per year (tpy) of coke product. Total emissions from the proposed project are above the thresholds requiring PSD review for nitrogen oxides (NO_X), carbon monoxide (CO), particulate matter ($PM/PM_{10}/PM_{2.5}$), sulfur dioxide (SO_2), sulfuric acid (H_2SO_4) mist, volatile organic compounds (VOCs) and greenhouse gases (GHGs).

Based on the EPA's review, we are providing the following comments to help ensure that the project meets federal Clean Air Act requirements, that the permit record will provide necessary information so that the basis for the permit decisions is transparent and readily accessible to the public, and that the record provides adequate support for the decisions.

1. In response to the EPA's comment concerning the evaluation of lower sulfur coal, comment 8 in our June 27, 2013, letter, the applicant provided several technical reasons as well as a brief discussion of the economic impacts associated with using a lower sulfur coal (1.1% sulfur content) beyond during the startup process to reduce SO_2 and H_2SO_4 emissions from the proposed facility. The EPA suggests that the SOB be revised to include a summary of this information provided by the applicant in their July 19, 2013, letter to Kentucky.

2. In the EPA's comment letter (June 27, 2013), we provided a comment regarding the setting of GHG best available control technology (BACT) limits for all emissions units, preferably on an output basis. According to the applicant's response document (page 4) from July 19, 2013, while they have been gathering CO_2 emissions data from the heat recovery coke-making process for 2 years, they still do not have sufficient data to establish output based limits (*e.g.*, lb CO_2/ton coke). The applicant did propose and Kentucky established tpy BACT limits on most processes

emitting GHGs. It is the EPA's understanding that the vast majority (1,301,000 tpy CO_2e) of GHG emissions come from the heat recovery coke ovens and are emitted through the main coking stack. The EPA still believes output-based limits are the most appropriate format for GHG BACT limits when relying on energy efficiency (*e.g.*, heat recovery and combustion optimization) for GHG control. However, in lieu of output-based GHG BACT limits, the EPA suggests additional monitoring and periodic stack testing and/or continuous emission monitoring of CO_2 emissions to ensure the tpy BACT limits are practically enforceable. Furthermore, this enhanced monitoring would provide additional information about the GHG emissions from the coke-making process to supplement the information the applicant has already been gathering.

3. According to the SOB (Table 6), Kentucky declared the PSD application complete on August 8, 2013. The EPA received an email from KDAQ on August 12, 2013, which included all of the supporting documents received at that time. However, the SOB indicates there have been many additional modeling files and other items related to the Air Quality analysis, which were dated after August 12, 2013. To date, these additional files have not been provided to the EPA. Consequently, the EPA can neither review/evaluate the Air Quality analysis performed by the applicant, nor evaluate the information and analyses presented in the Kentucky SOB. In order for the EPA to fulfill its oversight responsibility of the PSD program, all information (including that received after the application completeness determination date) that was used by Kentucky to make a determination regarding this project's compliance with the PSD program should have been provided to the EPA.

   Finally, the EPA notes that the SOB is dated November 27, 2013; however, according to the SunCoke Modeling Application Timeline (Table 6), the last document received by Kentucky is dated December 16, 2013. The EPA suggests the date on the SOB is revised to reflect this most recent information referenced in the SOB to avoid confusion for the public.

Thank you for the opportunity to provide our comments. If you have any questions regarding these comments or need additional information, please contact Heather Ceron at 404-562-9185.

Sincerely,

R. Scott Davis

R. Scott Davis
Chief
Air Planning Branch

cc: Rick Shewekah, KDAQ (via email)

Commonwealth of Kentucky
Division for Air Quality

COMMENTS AND RESPONSE

ON THE STATEMENT OF BASIS

ATTACHMENT 4

SESS Response to U.S. EPA Comments on SunCoke Energy South Shore Draft Construction and Operating Permit V-13-007, Plant ID 021-089-00047, Agency Interest No. 105793

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SunCoke Energy

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Permit Review Branch
Division for Air Quality

David J. Schwake
Director, North America
Business Development

SunCoke Energy, Inc.
1011 Warrenville Road
Suite 600
Lisle, IL 60532
630-824-1000 Phone
630-824-1001 Fax

February 6, 2014

Mr. James Morse
Division for Air Quality
Kentucky Department for Environmental Protection
200 Fair Oaks Lane, First Floor
Frankfort, Kentucky 40601-1134

RE: Response to EPA Comments on SunCoke Energy South Shore Draft Construction and Operating Permit

Permit:	V-13-007
Agency Interest:	105793
Activity:	APE20120001
Source ID:	21-089-00047

Dear Mr. Morse:

I am writing in response to comments submitted by the U.S. Environmental Protection Agency ("EPA") regarding the Kentucky Division for Air Quality ("KDAQ") draft Clean Air Act Title V Construction/Operating Permit No. V-13-007 ("Draft Permit") for the SunCoke Energy South Shore Coke Manufacturing Plant ("SESS" or "SESS Plant").

Kentucky's Prevention of Significant Deterioration ("PSD") program as codified in its State Implementation Plan ("SIP") is approved by EPA. *See* 40 C.F.R. § 52.923. Permitting decisions rendered by a duly authorized state agency such as KDAQ are entitled to deference, and are subject to challenge only if the decision was "without support of substantial evidence on the *whole* record" or was "arbitrary, capricious, or characterized by abuse of discretion." *See* Ky. Rev. Stat. Ann. § 13B.150(2) (emphasis added); *500 Assocs. v. Natural Res. & Envtl. Prot. Cabinet*, 204 S.W.3d 121, 132 (Ky. Ct. App. 2006); *Arkansas v. Okla*homa, 503 U.S. 91, 113 (1992); *Chevron v. NRDC*, 467 U.S. 837 (1984).

As explained below, all of EPA's comments are readily addressed when reviewing the complete administrative record, including the SESS Plant's permit application from December 10, 2012 ("Permit Application"). SESS provides the following detailed responses to the comments submitted by EPA.

Comment No. 1: EPA suggests revising the Statement of Basis ("SOB") for the Draft Permit to include a summary of the information provided by SESS in its July 19, 2013 letter to KDAQ relating technical reasons why low sulfur coal cannot be used beyond the startup process.

Response No. 1: SESS is amenable to the SOB being revised to include a summary of this information. Below is a proposed summary for KDAQ's consideration:

SunCoke Energy South Shore ("SESS") must purchase available coals that make quality coke throughout the life of the SESS Plant. Unfortunately, the availability and quality of metallurgical coals has been subject to a number of trends and events that make the prediction and control of coal sulfur content very challenging, not just in the long term but also the short term.

First, the supply of metallurgical coal in the United States has exhibited significant volatility in the last few years. Availability of coal has been impacted by several force majeure events at major U.S. metallurgical coal mines. During these events, the limited availability of alternative supplies has generally led to higher sulfur contents for replacement coals. Second, the sulfur of available coals has trended up over the past decade with higher sulfur metallurgical coals in the >1.5% sulfur content currently on the market. The coal quality of existing U.S. metallurgical mines, especially with regard to sulfur, has exhibited a deteriorating trend as reserves deplete. Because of this overall market drift toward higher sulfur coal, any permit limitations regarding sulfur must consider this reality.

The table below is from a coal reserve study by the U.S. Department of Energy and U.S. Energy Information Administration in 1993 depicting the relative volumes and sulfurs of Appalachia and Interior Region coals where this project resides. The sulfur content of available coals has been going up as lower sulfur coals are being depleted.

Table ES1. Estimates of the Demonstrated Reserve Base of Coal in the United States by Btu/Sulfur Ranges and Regions
(Million Short Tons Remaining as of January 1, 1992)

	Summary Sulfur Content Categories[a] (Pounds of Sulfur per Million Btu)							
Region[b]	< 0.60 (Low Sulfur)		0.61-1.67 (Medium Sulfur		1.68 (High Sulfur)		Total	
Appalachia	26,916.8	(16.0)	37,136.2	(26.6)	43,533.6	(26.0)	107,586.6	(22.6)
Interior	1,162.2	(0.7)	21,338.7	(15.3)	111,049.	(66.4)	133,549.9	(28.1)
West	140,459.0	(83.3)	81,315.8	(59.2)	12,686.4	(7.6)	234,461.2	(49.3)
U.S. Total	168,538.0	(100.0)	139,790.6	(100.0)	167,269.	(100.0)	475,597.7	(100.0)

[a]For detailed analyses, the EIA uses six sulfur content ranges. For general discussion and summary data, however, those six ranges are combined into the three qualitative ratings of low-, medium-, and high-sulfur content coal presented here. See also Appendix B, Table B3.
[b]States with qualified resource or reserve data in each region: **Appalachia**—Alabama, Georgia, eastern Kentucky, Maryland, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia. **Interior**—Arkansas, Illinois, Indiana, Iowa, Kansas, western Kentucky, Louisiana, Missouri, Oklahoma, Texas. **West**—Alaska, Arizona, Colorado, Idaho, Montana, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, Wyoming.
Notes: Numbers in parentheses are percentages of the U.S. totals. Btu = British thermal units.
Source: Energy Information Administration estimates.

[1]This assumes that 100 percent of the sulfur in the coal is converted to sulfur dioxide and none is retained in the ash.

The primary purpose for the 1.3% coal sulfur basis is to give the SESS Plant the ability to obtain metallurgical coal considering both short- and long-term availability. The 1.3% coal

SunCoke Energy

sulfur limit for SESS is the same as for other coke plants of this design. The Middletown Operations in Middletown, Ohio, and Haverhill Operations in Franklin Furnace, Ohio, have coal sulfur limits of 1.3%. Both of these facilities obtained PSD permits (Middletown – February 2010, Haverhill – December 2003) and these represent best available control technology ("BACT") limits. The SunCoke facility in Granite City, Illinois also has a PSD permit (March 2008) but that permit has no coal sulfur limit.

A more complete response was provided in pages 8-9 of SESS's July 19, 2013 letter to KDAQ responding to EPA's comments on the Permit Application.

Comment No. 2: EPA suggests, in lieu of output-based greenhouse gas ("GHG") BACT limits, the Draft Permit contain additional monitoring and periodic stack testing and/or continuous emission monitoring of CO_2 emissions to ensure the GHG BACT limits are practically enforceable.

Response No. 2: SESS is amenable to monitoring of CO_2 and this monitoring, through periodic stack testing, has already been addressed in the Draft Permit. Periodic stack testing of the coke ovens for PM, PM_{10}, $PM_{2.5}$, CO, NO_x, and VOC emissions is a provision in the Draft Permit. *See* Draft Permit, at 21. CO_2 measurements will be required as part of these stack tests to determine the molecular weight of the gas stream as part of the gas flow rate measurements. These main stack CO_2 measurements will be made available to the agency as they are today from our existing plant stack tests.

Comment No. 3: EPA states that there were many modeling files dated after August 12, 2013 that it did not receive based on information provided in the SOB, and EPA needs those files in order to review the air quality analyses performed by SESS and information presented in the SOB. EPA also suggests revising the date of the SOB to reflect the last document received by KDAQ on December 16, 2013.

Response No. 3: SESS confirms that the information listed in Table 6 in the SOB was provided to KDAQ. We do not know whether KDAQ's final analysis was based on additional documents and information not otherwise provided by SESS. In any case, SESS can provide additional copies of the information submitted if requested by KDAQ.

Sincerely yours,

David J. Schwake

cc: Mr. R. Scott Davis, Chief, Air Planning Branch, EPA, Region 4 (via email)
Ms. Heather Ceron, Chief, Air Permits Section, EPA, Region 4 (via email)
Mr. Sean Alteri, Director, KDAQ (via email)
Mr. Rick Shewekah, Manager, Permit Review Branch, KDAQ (via email)
Ms. Linda Martin, Supervisor, Metallurgy Section, KDAQ (via email)

Commonwealth of Kentucky
Division for Air Quality

COMMENTS AND RESPONSE

ON THE STATEMENT OF BASIS

ATTACHMENT 5

Sierra Club Comments on SunCoke Energy South Shore Draft Construction and Operating Permit V-13-007, Plant ID 021-089-00047, Agency Interest No. 105793

SIERRA CLUB
FOUNDED 1892

January 27, 2014

Mr. James Morse
Division for Air Quality
200 Fair Oaks Lane, 1st Floor
Frankfort, KY 40601

RE: Sierra Club Comments on SunCoke Energy South Shore Draft Construction and Operating Permit V-13-007, Plant ID 021-089-00047, Agency Interest No. 105793

Dear Mr. Morse:

Please accept these comments submitted on behalf of the Sierra Club regarding the Kentucky Division for Air Quality ("DAQ" or "Division") draft Clean Air Act Title V Construction\Operating Permit No. V-13-007 ("Draft Permit" or "Permit") for the SunCoke Energy South Shore Coke Manufacturing Plant ("SunCoke Plant" or "Plant"), owned by SunCoke Energy, Inc, Agency Interest No. 105793.

The Sierra Club is the oldest and largest grassroots environmental group in the United States, with almost 600,000 members nationally, including nearly 5,000 members in Kentucky. Sierra Club's members live, work, attend school, travel, and recreate in and around areas potentially affected by the emissions that the SunCoke Plant would produce if constructed. These members enjoy and are entitled to the benefits of natural resources including air, water and soil; forests and cropland; parks, wilderness areas and other green space; and flora and fauna, all of which would be negatively impacted by the SunCoke Plant's emissions.

As set forth in detail below, the Draft Permit cannot be issued for the following reasons: its BACT analysis is inadequate; it does not contain all applicable emissions standards; it is unenforceable due to ambiguous terms and insufficient monitoring and compliance provisions; and the Plant would contribute to multiple NAAQS violations if constructed. Moreover, DAQ violated public notice requirements when it issued the Permit. At a minimum, these public notice defects require re-issuance of the Permit and a new round of public comments.

I. DAQ Cannot Issue a Permit for the SunCoke Plant Because the Plant Will Contribute to Multiple NAAQS Violations.

The Clean Air Act and DAQ regulations prohibit the construction of a new source unless the owner/operator of the facility demonstrates that emissions from construction or operation of the facility will not cause or contribute to "air pollution in excess of any. . . national ambient air quality standard in any air quality control region." 42 U.S.C. § 7475(a)(3); *see also* 401 KAR 51:017 Section 9; 40 C.F.R. 51.166(k).

During the application phase, the applicant must demonstrate that:

> allowable emission increases from the proposed major source or major modification, in conjunction with all other applicable emissions increases or reduction, including secondary emissions, shall not cause or contribute to air pollution in violation of either of the following:
> (1) Any national ambient air quality standard in any air quality control region.
> (2) Any applicable maximum allowable increase over the baseline concentration in any area.[1]

In keeping with this requirement, the Clean Air Act requires a permit applicant to "conduct such monitoring as may be necessary to determine the effect which emissions from any such facility may have, or is having, on air quality in any area which may be affected by emissions from such source." 42 U.S.C. § 7475(a)(7). More specifically, at a minimum, the full PSD review must "be preceded by an analysis... by the State... or by the major emitting facility applying for such permit, of the ambient air quality at the proposed site and in areas which may be affected..." 42 U.S.C. § 7475(e)(1). This "preconstruction" analysis "*shall include* continuous air quality monitoring data *gathered for purposes of determining* whether emissions from such facility will exceed the [NAAQS or PSD increment]." 42 U.S.C. § 7475(e)(2) (emphasis added). Federal and state regulations similarly require the applicant to submit a pre-application analysis of ambient air quality in affected areas that includes at least one year of representative continuous air quality monitoring data. *See* 40 C.F.R. § 51.166(m)(1)(iv).

The Draft Permit fails by its own terms to comply with the sections of the Clean Air Act and Kentucky regulations excerpted above. Table 9 in the Permit's Statement of Basis shows that there are significant NAAQS violations in the area where the SunCoke Plant is to be constructed.[2] The 1-hour SO2 NAAQS for the area is 196.5 µg/m3.[3] The modeled 1-hour SO2 concentration *without* the SunCoke Plant is 1333.0 µg/m3, which is above the NAAQS threshold by nearly seven fold.[4] If the SunCoke Plant is built, the modeled concentration will rise to 1393.11 µg/m3.[5] The Clean Air Act and Federal and state regulations are unambiguous that Title V permits cannot be issued in such circumstances. 42 U.S.C. § 7475(a)(3); 401 KAR 51:017 § 9(1). The Division cannot issue a construction permit when its own modeling data shows that there are NAAQS violations in the area where the proposed facility would be constructed.

The 1-hour SO2 standard is not the only NAAQS for which there are modeled violations demonstrated in the Draft Permit's Statement of Basis. Table 9 in the Statement of Basis also shows violations of the 24-hour PM10 NAAQS and the 24-hour PM2.5 NAAQS. The 24-hour PM10 NAAQS for the area is 150 µg/m3.[6] The modeled 24-hour PM10 concentration without the SunCoke Plant is 256.3 µg/m3 and will rise to 291.3 µg/m3 if the SunCoke Plant is constructed.[7] The 24-hour PM2.5 NAAQS for

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[1] 401 KY. ADMIN. REGS ("KAR"), 51:017 § 9.
[2] Statement of Basis at 53.
[3] *Id.*
[4] *Id.*
[5] *Id.*
[6] *Id.*
[7] *Id.*

the area is 35 μg/m3.[8] The modeled 24-hour PM2.5 concentration without the SunCoke Plant is 129.2 μg/m3 and will rise to 148.5 μg/m3 if the SunCoke Plant is constructed.[9] Again, for the Division to issue a construction permit for the SunCoke Plant when its modeling data shows that there are NAAQS violations to which the SunCoke Plant would contribute would constitute a blatant violation of the plain language of the CAA and Kentucky regulations.

II. The Emission Limits in the Draft Permit Fail to Satisfy the BACT Requirements of the Clean Air Act.

It is undisputed that the Plant is subject to Best Available Control Technology (BACT) requirements for a number of air pollutants.[10] BACT determinations require a thorough analysis of emission control technologies and involve a well-settled method of evaluation. The Draft Permit fails in multiple respects to satisfy the Clean Air Act's BACT requirements.[11]

A. BACT Requires Identifying the Maximum Emissions Reductions Achievable and Does Not Hinge Solely on Previous BACT Determinations Made for Other Facilities.

The Clean Air Act defines BACT as:

> An emission limitation based on the maximum degree of reduction of each pollutant subject to regulation… emitted 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 the 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 pollutant.[12]

By using the terms "maximum" and "achievable" in the definition of BACT, the Clean Air Act sets forth a "strong, normative" requirement that "constrain[s]" agency discretion in determining BACT. *Alaska Dep't of Envtl Conservation v. EPA*, 540 U.S. 461, 485-86 (2004). 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 to specific collateral impact concerns.[13] *Alaska Dep't of Envtl. Conserv. v. EPA*, 298 F.3d 814, 822 (9th Cir. 2002). 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 (E.A.B. Sept. 27, 2006).

BACT's focus on the maximum emission reduction achievable makes the standard both technology-driven and technology-forcing.[14] A proper BACT limit must account for both general

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[8] *Id.*
[9] *Id.*
[10] *See* Draft Permit, at 13.
[11] CAA §165(a), 42 U.S.C. § 7475(a); 401 KAR 51:017.
[12] 42 U.S.C. § 7479(3).
[13] Note that 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 (E.A.B. Apr. 28, 1997); NSR Manual at B.29.
[14] U.S. EPA, New Source Review Workshop Manual – Draft (Oct. 1990), at B.12, (hereinafter "NSR Manual") ("[T]o satisfy the legislative requirements of BACT, EPA believes that the applicant must focus on technologies

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, with standards set accordingly.[15] For instance, technology transfer from other sources with similar exhaust gas conditions must be considered explicitly in making BACT determinations.

Notwithstanding its statutory mandate to choose the *maximum achievable* degree of emission reductions when setting BACT, DAQ proposed BACT limits that it touted as being "comparable" to previous set BACT limits.[16] It appears that DAQ's BACT analysis began and ended with review of the RACT/BACT/LAER Clearinghouse (RBLC) database. Statements such as "this system is not listed as having been successfully demonstrated in any RBLC determination and is not considered a feasible option for SESS" appear throughout the Statement of Basis and reveal a fundamentally flawed BACT determination process.[17] As described in the preceding paragraph, the universe of sources that one must consider in making a BACT determination is much broader than just recently permitted sources. Other information sources must be considered to assure that the lowest achievable emission limit is specified as BACT. These other sources include control technology vendors, technical literature, and foreign experience.[18] Moreover, even if it were legally sufficient to look only at recent BACT determinations set for other facilities, the emissions reductions set in the Draft Permit are *still* inadequate. The NUCOR permit referenced in the Statement of Basis set enforceable limitations of 0.071 lbs/ton NOx and 0.035 lb/ton VOC. In contrast, the Draft Permit's BACT limits are 1.0 lb/ton NOx and 0.04 lbs/ton VOC. DAQ can only implement BACT limits less stringent than the maximum achievable if it can show compelling, facility-specific collateral impacts, which DAQ does not do here. DAQ clearly employed a fundamentally flawed process in making its BACT determinations which resulted in emissions limits that are much weaker than the maximum achievable standards. The Draft Permit cannot be issued until DAQ corrects these critical errors in its BACT determinations and re-circulates a revised permit for public review.

B. DAQ's BACT Analysis Failed to Follow the 5-Step, Top-Down Process that Kentucky Adheres to in its BACT Determinations.

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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."). The NSR Manual is available at http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf.

[15] 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*, 2005 EPA App. LEXIS 29 at *30-31, 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. *See NSR Manual* at B.5.

[16] *See* Statement of Basis, at 8, 18, 21, 30, 37.

[17] *Id.* at 36. *See also id. at* 17, 18, 21, 22, 24, 37, 38, 43, 44, 46 (according significant and often exclusive weight to BACT listings contained in the RBLC).

[18] NSR Manual at B.11.

i. The 5-Step, Top-Down BACT Determination Process Applies.

Kentucky law contains a definition of BACT that is similar to the Clean Air Act's definition. 401 KAR 51:001, § 1(25). Under both definitions, BACT requires a forward-looking analysis of what the facility can achieve in the future, based on what is presently known about the effectiveness of the best pollution control options. *Newmont Nevada Energy Investments, LLC, TS Power Plant*, PSD Appeal No. 05-04, Slip Opinion at 16 (EAB Dec. 21, 2005).

EPA regulations require the Division, as the PSD permitting authority, to perform and document an analysis to ensure that BACT limits are at least as stringent as federal BACT. 42 U.S.C. § 7475(a)(4); 40 C.F.R. § 52.21(j). To implement BACT permitting, EPA established a "top-down BACT analysis" process, which it outlined in its New Source Review Workshop Manual (Draft October 1990) ("NSR Manual"). EPA's Environmental Appeals Board has adopted the use of the NSR Manual as controlling authority when deciding cases. *See In re Masonite Corp.*, 5 E.A.D. 558 (EAB 1994); *Inter-Power of New York, Inc.*, 5 E.A.D. 135 (EAB 1994). The Division implements PSD permitting in Kentucky by applying the NSR Manual's process as the appropriate analysis for new source review determinations. The Environmental Appeals Board has held that, when a state permitting agency attaches importance to the NSR Manual, the Manual then serves as "an important reference point in assessing whether [the agency] has acted rationally in the context of a given permit." *In re General Motors, Inc.*, 10 E.A.D. 360, 366 (EAB 2002) (discussing Michigan's reliance on the NSR Manual). The top-down BACT analysis consists of five steps:

1. Identify all control technologies (including lowest achievable emission rate or LAER).
2. Eliminate technically infeasible options.
3. Rank the remaining control technologies by control effectiveness.
4. Evaluate the most effective control and document results.
5. Select BACT.

NSR Manual at Table B-1. The first step of this process requires all available control technologies to be identified before any are rejected as technically infeasible or due to cost or other factors. After all available control technologies are identified, the most stringent or top alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify the rejection of the top alternative. NSR Manual at B.2. If the top alternative is rejected, the next most stringent option is selected as BACT unless the applicant demonstrates, similar to the top alternative, that technical, environmental, or economic considerations justify the rejection of the second option. NSR Manual at B.2.

Although the focus of a BACT analysis is mainly on the control technology or pollution prevention practices applicable to an applicant source, BACT actually refers to the numeric emission limit (i.e., pounds per Million Btu heat input) that corresponds with a specific, "best," control option (e.g., a selective catalytic reduction system). *In re Three Mountain Power, LLC*, 10 E.A.D. 31, 54 (EAB 2001). Therefore, DAQ must determine the top pollutant control option and set the corresponding limit based on the maximum pollution reduction achievable by that control technology. BACT is an emission limit "based on the maximum degree of reduction... that is achievable..." 42 U.S.C. § 7479(3). In other words, even after selecting the top control technology, the Division must also ensure that the BACT emission limit is the lowest achievable emission rate for each pollutant based on the control potential of the top technology. The NSR Manual clearly requires the lowest possible emission rate to be selected as the

BACT limit. NSR Manual at B.29. If the lowest emission rate is not set as BACT, "the rationale for this finding needs to be fully documented for the public record." NSR Manual at B.29. U.S. EPA has continuously stressed the importance of a rigorous BACT analysis process and complete record supporting the permitting agency's determinations:

> The BACT analysis is one of the most critical elements of the PSD permitting process. As such, it should be well documented in the administrative record. A permitting authority's decision to eliminate potential control options as a matter of technical infeasibility, or due to collateral impacts, must be adequately explained and justified.[19]

Therefore, when establishing a BACT limit, DAQ must identify the most effective pollution control option, and must set BACT based on that option unless the applicant can demonstrate that the most effective pollution control option must be rejected based on energy, environmental, or economic impacts-which are unique to the specific facility. As EPA has repeatedly stated, the collateral "energy, environmental, or economic impacts" exception ("collateral impacts" exception) to the top-control option is narrow, to be used sparingly on unique circumstances at the source. NSR Manual at B.29.

> The [collateral impacts] clause [of the BACT definition] allows rejection of the most effective technology as BACT only in limited circumstances. The collateral impacts clause operates primarily as a safety valve whenever ***unusual circumstances specific to the facility*** make is appropriate to use less than the most effective technology.

In re Kawaihae Cogeneration *Project*, 7 E.A.D. 107, 116-17 (EAB 1997) (emphasis original); *see also In re World Color Press, Inc.*, 3 E.A.D. 474, 478 (Adm'r 1990) (collateral impacts clause focuses on the specific local impacts).

ii. DAQ Improperly Applied the 5-Step BACT Determination Process and Eliminated Control Technologies for Invalid Reasons.

The Division failed in a number of respects to adequately perform the top-down BACT analysis, rendering the draft permit inadequate. In determining BACT for SO2, the Division eliminated a potential control technology – a wet scrubber – based exclusively upon consideration of incremental cost.[20] As the EAB held in *General Motors*, however, permitting agencies cannot rely exclusively on incremental cost as the sole measure of a control technology's economic feasibility.[21] They must also consider the control option annual cost, which is calculated differently from the incremental cost.[22] As the EAB in *General Motors* reasoned: "undue focus on incremental cost-effectiveness can give an impression that the cost of a control alternative is unreasonably high, when, in fact, the cost effectiveness, in terms of dollars per total ton removed, is well within the normal range of acceptable BACT costs."[23] This is precisely the case with the SunCoke facility, as the control option annualized cost of a wet scrubber is $2141/ton SO2, which is

[19] *In re Knauf Fiber Glass, GmbH,* 8 E.A.D. 121, 131 (EAB 1999); *see also* NSR Manual at B.26-B.29; *In re General Motors, Inc.*, 10 E.A.D. 360, 379 (EAB 2002); *In re Steel Dynamics, Inc.*, 9 E.A.D. 165, 206-07 (EAB 2002); *In re Masonite Corp.*, 5 E.A.D. 551, 564-69 (EAB 1994).
[20] *See* Statement of Basis, at 31.
[21] *General Motors,* at 10-11.
[22] *Id.*
[23] *Id.*

comparable to other BACT costs.[24] Moreover, even if incremental cost were the sole measure of economic feasibility, the Division's SO2 BACT analysis would still be improper because the Division did not indicate the unusual, facility-specific circumstances that would make it appropriate to reject the wet scrubber on the basis of collateral impacts.[25]

Likewise, in determining BACT for NOx, the Division performed an inadequate analysis of control technology feasibility. It is the Division's duty to "adequately explain and justify" any decisions to eliminate potential control options for reasons of technical infeasibility.[26] An adequate explanation requires, among other things, documented evidence.[27] Yet the Division's justification for eliminating both SNCR and HSSCR consisted of just a few unsupported sentences:

> As with the SNCR, there is the potential for ammonia slip and the resultant formation of ABS. This sticky substance would foul the downstream HRSGs and is difficult to control. This would increase the maintenance required and the cost. The HSSCR is therefore considered infeasible for use with the SESS facility.[28]

This falls well short of the adequate, documented explanation required by law.[29] Moreover, the Division impermissibly cited increased maintenance as the dispositive concern in this perfunctory analysis. Even if the SunCoke facility must redesign certain equipment in order to handle a SNCR or HSSCR, that would not render these controls technically infeasible. NSR Manual at B.20 ("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."). Fouling and ammonia slip are common design factors in all SNCRs.[30] The Draft Permit cites no unique characteristics in the Suncoke design that are not present in other sites which use SNCRs to control NOx emissions. Because SNCR and HSSCR cannot be excluded as technically infeasible, the Division must perform cost analysis for these technologies.

Beyond the SNCR and HSSCR, the Division eliminated several additional NOx control devices for impermissible reasons.[31] The Division excluded control strategies because the "technology requires a wastewater treatment plant," or "[the technology] has only been demonstrated with small to medium-sized boilers."[32] Neither of these reasons provides an adequate justification for rejecting control technologies. As described above in the context of the SNCR and HSSCR, the fact that a control technology might require design alterations does not mean that the technology is infeasible. Moreover,

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[24] *See generally* U.S. EPA, Emission Control Technologies, *available at* http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter5.pdf.

[25] *See In re Kawaihae Cogeneration Project*, 7 E.A.D. 107, 116-17.

[26] NSR Manual at B.26-B.29; *Knauf*, 8 E.A.D. at 131. ("A permitting authority's decision to eliminate potential control options as a matter of technical infeasibility, or due to collateral impacts, must be adequately explained and justified.").

[27] *Id.*

[28] *See* Statement of Basis, at 35.

[29] *See* NSR Manual at B.26-B.29; *Knauf*, 8 E.A.D. at 131

[30] *See generally* U.S. EPA, NOx Controls, 1-7, *available at* http://www.epa.gov/ttn/catc/dir1/cs4-2ch1.pdf.

[31] *See* Statement of Basis, at 56.

[32] *Id.*

these technologies have been widely used during the combustion of coal.[33] Partial combustion of the same coal does not present unique technical challenges that are grounds for excluding these technologies.

C. The Draft Permit Does Not Meet BACT Requirements for Startup and Shutdown Operations.

BACT emission limits must be met on a continual basis at all levels of operation. 401 KAR 51:001 Section 1 (25); 401 KAR 51:017 Section 8; 42 USC §§ 7475(a)(4) and 7479(3); 40 CFR §§ 51.166(b)(12) and (j)(2). Startups and shutdowns are part of normal operation and the emissions that occur during these periods must be included in the BACT analysis and limited in the permit. *See, e.g., In re Tallmadge Generating Station,* Order Denying Review in Part and Remanding in Part, PSD Appeal No. 02-12, slip op. (EAB May 21, 2003) ("BACT requirements cannot be waived or otherwise ignored during periods of startup and shutdown."); *In re RockGen Energy Center*, 8 E.A.D. 536, 553-55 (EAB 1999) (holding that PSD permits may not contain blanket exemptions allowing emissions in excess of BACT limits during startup and shutdown).[34] "EPA's long-held interpretation is that emission limitations in PSD permits apply at all times and may not be waived during periods of startup and shutdown." *See, e.g., Tallmadge Energy Center* [sic], slip op. at 24. *In re Louisville Gas & Electric Co.*, Partial Order Responding to March 2, 2006 Petition, at 10 (Sept. 10, 2008). Exemption of a source "from any concentration limits during startup and shutdown," including short-term limits, is "potentially a...serious concern." *See In re Indeck-Niles Energy Center*, PSD Permit No. 364-00A; PSD Appeal No. 04-01, 2004 EPA App. LEXIS 36, n. 9 (EAB Sept. 30, 2004) (emphasis added).

For a permitting agency to properly exempt a facility from startup and shutdown emission limits, the agency must make on-the-record, pollutant-by-pollutant determinations as to whether "compliance with existing permit limitations is infeasible during startup and shutdown." *In re RockGen Energy Center*, PSD Appeal No. 99-1, 8 E.A.D. 536 at 553 (Aug. 25, 1999). These determinations must be thoroughly documented, and take into account the extent to which control equipment for the different pollutants will continue to function during startup, shutdown, and malfunction.[35] Unless DAQ justifies an exemption with this type of rigorous analysis, it must include emission limitations for periods of startup and shutdown in order to provide the "continuous" emissions limitations required by the Clean Air Act.[36] 401 KAR 51:001 Section 1 (25); 401 KAR 51:017 Section 8; 42 USC §§ 7475(a)(4) and 7479(3); 40 CFR §§ 51.166(b)(12) and (j)(2).

[33] *See generally* U.S. EPA, Air Pollution Control Technology Fact Sheet, *available at* http://www.epa.gov/ttn/catc/dir1/fsncr.pdf.

[34] *See also* Memorandum from John B. Rasnic, EPA Stationary Source Compliance Division, to Linda M. Murphy, EPA Region 1, *Automatic or Blanket Exemptions for Excess Emissions During Startup, and Shutdowns Under PSD* (January 28, 1993) ("Rasnic 1993 Memorandum"); 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"). We note that BACT covers periods of so-called malfunction to the extent that the malfunction could have been anticipated and avoided through proper maintenance. *See id.*

[35] *See, e.g., In re Indeck-Elwood LLC PSD Permit No. 197035AAJ* Order Denying Review in Part and Remanding In Part, September 27, 2006 at p. 70.

[36] *See* 78 Fed. Reg at 54,822, 54,825 ("The legal and factual basis supporting the concept of an affirmative defense for malfunctions does not support providing an affirmative defense for normal modes of operation like startup and shutdown.").

While the Draft Permit contains some record-keeping and monitoring requirements for periods of startup and shutdown,[37] it does not contain any emission limitations, in violation of the law. Most portions of the Permit simply fail to mention startup and shutdown periods, while at least one appears to exempt such periods from emission limitations without any justification. The Permit states "*excluding the startup and shutdown periods*, if any 3-hour average sulfur dioxide or sulfuric acid value exceeds the standard, the permittee shall . . . . [inspect and make repairs]."[38] Neither the Draft Permit nor the Statement of Basis provide any explanation for this apparent exemption, much less the thoroughly documented, pollutant-specific analysis which is required under Federal and state law. *See RockGen Energy Center*, at 553. There is no evidence that the Division considered ways to reduce or eliminate excess emissions during startup and shutdown, beyond the occasional mention of plans that are to be developed in the future, by the permittee.[39] To the extent that any startup and shutdown plans have been made, the crucial emissions elimination/reduction analysis has been delegated to the permittee, to be conducted at an undetermined future time, and will not be subject to a public approval process. This scheme is not acceptable under the CAA. *Tallmadge*, slip op at 26-27; *RockGen*, 8 E.A.D. 536, 551-555. The permit must describe the design, control, and methodological, or other changes that are appropriate for inclusion in the permit to minimize allowed excess emissions during startup and shutdown. Tallmadge, slip op. at 27. The Draft Permit must be revised and re-issued to establish BACT limitations for startup and shutdown.

III. The Draft Permit Does Not Contain All Applicable Emission Limitations and Standards, as Required by Kentucky Regulations.

Another fundamental flaw with the Draft Permit is its failure to list all applicable emission limitations and standards. The Division's regulations for issuing Title V permits state: "permits shall contain emissions limitations and standards, including operational requirements and limitations that assure compliance with all applicable requirements *at the time of permit issuance*."[40] In contravention of this requirement, at multiple points the Draft Permit simply defers compliance demonstrations to a later, unspecified time. For example, the Draft Permit states that "compliance with 40 CFR 60.254(c), shall be demonstrated with submission to the Division of the required fugitive coal dust control plan before commencing start-up."[41] Similarly, the Permit says that compliance with 401 KAR 51:017 "shall be demonstrated by inclusion of proposed BACT controls in the fugitive coal dust control plan and compliance with 40 CFR 60.254."[42] These provisions would allow the Division to make BACT determinations outside of the permit process and without any opportunity for public or U.S. EPA review. A fugitive coal dust control plan must be made available prior to the issuance of a permit, or sufficient portions of that plan must be included in the Draft Permit to meet the regulatory requirement that "permits

[37] *See, e.g.,* Draft Permit, at 25, 27, 98.
[38] Draft Permit, at 25 (emphasis added). *See also id.* at 102 ("The emission limitations set forth in 40 CFR 63, Subpart L, shall *apply at all times except during a period of startup, shutdown, or malfunction*. The startup period shall be determined by the Administrator and shall not exceed 180 days." (emphasis added)).
[39] *See* Draft Permit, at 107.
[40] Cabinet Provisions and Procedures for Issuing Title V Permits, *available at* http://air.ky.gov/SiteCollectionDocuments/52-020%20IBR%20Final.pdf. (emphasis added). *See also* CAA § 504(a), 43 U.S.C. § 7661c(a) (requiring that every Title V permit "assure compliance by the source with all applicable requirements); 40 C.F.R. §70.1.
[41] Draft Permit, at 5.
[42] *Id.*

shall contain emission limitations and standards, including operational requirements and limitations that assure compliance with all applicable requirements *at the time of permit issuance*."[43]

In addition to impermissibly postponing compliance demonstrations, the Draft Permit also entirely omits multiple applicable regulations, including 401 KAR § 59:015. Section 59:015 applies to any indirect heat exchanger, which is defined as "a piece of equipment, apparatus, or contrivance used for the combustion of fuel in which the energy produced is transferred to its point of usage through a medium that does not come in contact with or add to the products of combustion."[44] The combustion of coke gas at the SunCoke Plant will produce energy which is transferred through to the HRSGs.[45] This apparatus qualifies as an indirect heat exchanger under the broad definition established by 401 KAR § 59:015. DAQ's failure to include § 59:015 in the Draft Permit is a violation of the Clean Air Act and Federal and Kentucky regulations.[46]

The Draft Permit also fails to include 40 CFR 60 Subpart Db or Subpart Dc, which implement performance standards for steam generating units. The Statement of Basis justifies excluding Subpart Db from the Permit on the basis of 1999 U.S. EPA Policy determination, which held that, generally, Subpart Db does not apply to Heat Recovery Steam Generators (HRSGs) involved with coke ovens.[47] However, the reasoning in this EPA policy determination shows that Subpart Db must apply to the SunCoke Plant. Crucially, the coke ovens involved in the EPA policy determination had "no burners in the duct or the boilers, no combustion air inlets in the boilers, *and no supplemental fuels (e.g., natural gas, oil) combusted*."[48] In contrast, the SunCoke Plant will use natural gas as a supplemental fuel for steam generation.[49] This is a legally relevant distinction, as the absence of supplemental fuels was central to EPA's reasoning in its policy determination.[50] The Draft Permit must either include appropriate terms and conditions to ensure that the natural gas is not used for steam generation or include in the Permit the terms and conditions from the appropriate regulations, including Subpart Db.

The Draft Permit also improperly excludes the Acid Rain Program (ARP) by relying upon an inapplicable exemption. 40 C.F.R. § 72.6 exempts cogeneration units from the ARP, provided they supply "equal to or less than one-third [their] potential electrical output capacity or equal to or less than 219,000 MWE-hrs actual electric output on an annual basis to any utility power distribution system for sale."[51] In order to stay under the exemption's 219,000 MWE threshold, the Draft Permit improperly segments the electricity produced from each individual generator.[52] However, the ARP applicability determination must be based on the *combined* electricity production from all three generators. The exemption applies only to a "generation unit." "Generation unit" and "generator" are not interchangeable terms, as is evident from

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[43] Cabinet Provisions and Procedures for Issuing Title V Permits (emphasis added); CAA § 504(a); 40 C.F.R. §70.1.
[44] 401 KAR 59:015 § 1(5).
[45] *See* Statement of Basis, at 2 ("The heat released from combusting the gases in the flues and tunnel is routed to Heat Recovery Steam Generators (HRSGs) which use the heat to create steam for running an electricity generating turbine capable of producing 40-75 MW of power.").
[46] *See* Cabinet Provisions and Procedures for Issuing Title V Permits; CAA § 504(a); 40 C.F.R. §70.1.
[47] Statement of Basis at 6; U.S. EPA Applicability Determination Index (1999), *available at* http://cfpub.epa.gov/adi/pdf/adi-nsps-9900003.pdf.
[48] Applicability Determination Index.
[49] *See* Draft Permit, at 44. (referencing the natural gas lances).
[50] Applicability Determination Index.
[51] *See* 40 C.F.R. 72.6(b)(4).
[52] Draft Permit, at 66.

the fact that Acid Rain regulations contain distinct definitions for each term.[53] Moreover, in prior policy determinations, U.S. EPA has factored multiple generators into a single "generation unit" in calculating whether the unit has exceeded the ARP's 219,000 MWE threshold.[54] If the Division were to base its applicability determination on the *combined* electricity production from all three generators as required by law, it would conclude that the ARP applies, since the combined electricity production exceeds the MWE threshold. The Permit must be re-drafted to include and ensure compliance with all applicable ARP requirements, including the requirements to apply for and receive an Acid Rain Permit and to monitor and report emissions.[55]

The Draft Permit also fails to include adequate mercury controls, which is a critical omission given that the Plant is projected to release approximately 400 lbs of mercury annually. The Statement of Basis contains some discussion of mercury, but ultimately the Permit does not require any additional, mercury-specific controls beyond what the Permit already requires for PM10/PM2.5 emissions.[56] The Permit purports to "control" mercury emissions through technology which DAQ mandated as a result of its BACT analysis for particulate matter, which is improper under Kentucky regulations.[57] Kentucky's air toxic regulation states that "no owner or operator shall allow any affected facility to emit potentially hazardous matter of toxic substances in such quantities or duration as to be harmful to the health and human welfare of humans, animals and plants."[58] A BACT analysis for particulate matter cannot substitute for the health-based determination required for mercury. Neither the Permit nor its supporting material find that 400 lbs of mercury is not harmful to the health and welfare of humans, animals, and plants. The Permit's failure to include a health-based risk analysis is a clear violation of 401 KAR 63:020.

The Clean Air Act requires application of Maximum Achievable Control Technology Standards ("MACT") for all hazardous air pollutants, of which mercury is one. See CAA Sections 112(d), 112(b). The "maximum degree of reduction in emissions deemed achievable for new sources shall not be less stringent than the emission control that is achieved in practice by the best controlled similar source." Id. EPA establishes National Emission Standards For Hazardous Air Pollutants (NESHAPs) for source categories, including coke ovens [cite: 68 FR 18007 and 58 FR 57898], which are applicable to this application.

Because the proposed coking facility may meet the definition of a facility covered by the utility MATS rule, DAQ must ensure compliance with the rule in its permit, which it has not done. EPA also recently set standards for hazardous air pollutants from coal-fired electric utility steam generating units ("utility MATS rule"), 77 FR 9304 (February 16, 2012) and 78 FR 24073 (April 24, 2013). The utility MATS rule applies to coal-fired electric generating units (i.e., units burning coal more than 10% of the average annual heat input during any 3 consecutive calendar years) of more than 25 megawatts electric that serves a generator that produces electricity for sale. 40 CFR 63.10042. This definition includes a "fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its

[53] *See* 40 CFR 72.2.
[54] *See* http://www.epa.gov/airmarkets/progsregs/arp/docs/conoco.pdf ("If the 219,000 MWe-hr ceiling is exceeded, then the kilns will become affected units and will have to comply with all applicable requirements under the Acid Rain Program. This includes the requirements to apply for and receive an Acid Rain permit (under 40 CFR part 72) and to monitor and report emissions (under 40 CFR part 75).")
[55] *See* 40 CFR 72; 40 CFR 75.
[56] Statement of Basis at 46-47.
[57] 401 KAR 63:020.
[58] *Id.*

potential electric output capacity and more than 25 MWe output to any utility power distribution system." Id. Because the proposed facility appears to meet this definition, DAQ must demonstrate the facility's compliance with the utility MATS rule.

IV. The Draft Permit Contains Insufficient Testing, Monitoring, Reporting, and Recordkeeping Requirements to Ensure Compliance with the Permit's Terms and Conditions.

Title V permits must include compliance certification, testing, monitoring, reporting and recordkeeping requirements sufficient to assure compliance with the terms and conditions of the permit. 40 CFR § 70.6(c)(1). With respect to monitoring specifically, Title V permits must include "periodic monitoring sufficient to yield reliable data from the relevant time period that are representative of the source's compliance with the permit." 40 C.F.R. § 70.6(a)(3)(i)(B).[59] As the D.C. Circuit recently recognized, infrequent monitoring is insufficient to ensure compliance with a short-term emission limit. *Sierra Club v. EPA*, 536 F.3d 673, 675 (D.C. Cir. 2008) (noting, as an example, that annual monitoring would not ensure compliance with a daily emissions limit). The NSR Manual likewise emphasizes the necessity of ensuring that emissions limits are practically enforceable. As the Manual states:

> To be enforceable, the permit must also specify that the controls be equipped with monitors and/or recorders measuring the specific parameters cited in the permit or those which ensure the efficiency of the unit as required in the permit. Only through these monitors could an inspector instantaneously measure whether a control was operating within its permit requirements and thus determine an emissions unit's compliance. It is these types of additional permit conditions that render other permit limitations practically and federally enforceable.

The Manual also stresses the need to incorporate "continuous, direct emissions measurements" into a permit's monitoring requirements wherever feasible. NSR Manual at H.6.[60]

The Draft Permit fails in many respects to meet the testing and monitoring standards that Title V Permits must satisfy. The Permit's BACT requirements for SO2 improperly rely on a long-term compliance demonstration to protect short-term limits.[61] One operating limitation outlined in the Permit is that "sulfur content, based on a monthly composite sample, shall be limited to 1.3 percent by weight of coal."[62] Using a monthly composite sample to demonstrate compliance with the SO2 standard does not ensure that the 1-hour, 3-hour, and daily SO2 BACT requirements are satisfied.[63] Similarly, the Permit states that charging operations "shall be limited to 20 ovens charged per hour."[64] This is unenforceable, as there are no monitoring or recordkeeping requirements to ensure compliance with the hourly standard. The majority of recordkeeping requirements are based upon a 30-day average, which will not reveal violations of an hourly standard.

[59] *See also* Cabinet Provisions and Procedures for Issuing Title V Permits, incorporated by reference by 401 KAR 52:020. (noting that Title V permits must contain "all emissions monitoring and analysis procedures and test methods that are specified in the applicable requirements, including those in [Section 114 of the Clean Air Act].").
[60] *See also Sierra Club v. Public Serv. Co.*, 894 F. Supp. 1455, 1460 (D. Colo. 1995).
[61] *See* Draft Permit, at 20.
[62] *Id.*
[63] Additionally, it is not clear if the percentage BACT limit is based upon wet or dry coal. As discussed above, both "wet coal" and "dry coal" must be clearly defined in the Permit to give either term enforceable meaning, and thus comply with applicable regulations.
[64] Draft Permit, at 13.

The emission limits for the Quench Tower suffer from similar deficiencies.[65] The Quench Tower operates by rapidly cooling hot coke with water. Despite the fact that there is no wet coal involved in the quench process, the emission limits listed in the Permit are based upon emissions of particulate matter per ton of wet coal. Additionally, the permit appears to require only an initial compliance test with no periodic testing to ensure continuing compliance. By using an improper metric to measure compliance and not requiring sufficient testing, the Permit all but ensures violations of the Quench Tower's emission limits.

The same flaws can be found in the emission limits for SunCoke's cooling towers. Emission rates from cooling towers depend upon the draft rate, circulation water rate, and TDS content of the water. The Permit fails to monitor or set a BACT through limiting TDS content in the circulating water, and it also fails to require periodic testing to ensure that design drift rate is not degrading with time.[66] Many other cooling towers have set TDS limits and required testing or evaluation for drift rates. Omitting these testing and monitoring requirements will fatally undermine the Division's ability to enforce the Permit's terms.

The Permit also fails to include adequate enforcement provisions for the rated capacity of the coal charging operation. The capacity is listed as "500 ton/hr per machine and 1,226,400 tpy wet coal total."[67] While the permit states that the annual processing limit is meant to be enforceable, the Permit contains no such provisions for the hourly limit.

The Draft Permit cannot be issued as written, as it does not contain compliance certification, testing, monitoring, reporting and recordkeeping requirements sufficient to assure compliance with the terms and conditions of the permit. 40 CFR § 70.6(c)(1); 401 KAR 52:020.

V. Ambiguous and Undefined Terms Render Many of the Draft Permit's Provisions Unenforceable.

The Clean Air Act states that Title V permits "shall include enforceable emission limitations and standards," and "shall set forth inspection, entry, monitoring, compliance certification, and reporting requirements to assure compliance with the permit terms and conditions." 42 U.S.C. § 7661c(a) and (c); 40 C.F.R. § 70.6(c)(1). For a permit condition to be enforceable, the permit must leave no doubt as to what, exactly, the permittee must do to satisfy that condition. As EPA has explained,

> 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 intentionally or unintentionally prevent enforcement.

U.S. EPA Region 9 Title V Permit Review Guidelines (Sept. 9, 1999), at III-46. *See also* 401 KAR 50:055.

Many of the Draft Permit's terms are unenforceable as written, either because they are not defined or because they are ambiguous. Issuing vague or undefined permit terms will not ensure

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[65] Draft Permit, at 36-38.
[66] Draft Permit, at 59.
[67] Draft Permit, at 12.

compliance with the Draft Permit's conditions, and thus violates the CAA and its implementing regulations.[68] The Permit's ambiguous and\or undefined terms include, but are not limited to:

- "Wet tons of coal"/"wet coal."[69] Wet coal may be a term of art in the coal or coking industry, but it must be defined in reference to a U.S. EPA definition or a published industry standard in order to be practically enforceable. The definition of wet coal should include the ways in which it is different from "dry coal."
- "Normal operation."[70] This phrase is not explicitly defined in the Draft Permit, and thus is vague and unenforceable. Without a definition that confers enforceable specificity to that term, SunCoke is effectively allowed to use the most favorable, selectively-picked data to demonstrate compliance even if that data is not representative of the Plant's typical operations.
- "Pounds per dry ton coal."[71] BACT for various pollutants is listed in the format of "lbs/dry ton coal." It is unclear how wet coal is different from dry coal, and how to convert between the two metrics. The conversion rate, as well as the data necessary to make the conversion calculation, must be specified in the Permit.

The Division's failure to define key terms in the Draft Permit makes it unenforceable as a practical matter. The Division must re-issue the Draft Permit and rectify these ambiguities and omissions.

VI. The Draft Permit Fails to meet Public Participation Requirements.

The Draft Permit contains multiple public notice defects which alone is grounds for re-issuing the permit and restarting the public comment process. 401 KAR 52:100 governs the public notice procedures which Title V Air Permit Applicants must follow.[72] The purpose of the public notice process, as delineated by 401 KAR 52:100, is to allow members of the public to have meaningful input on permitting activities which will affect their communities. Multiple defects in the Draft Permit contravene both the purpose and plain language of the public notice procedures, as delineated in 401 KAR 52:100.

First, the Draft Permit does not contain the address of the proposed facility, as is required by regulation. 401 KAR 52:100 § 5(2) clearly states that among the mandatory information required in a public notice is the "Name and address of the permit applicant and, if different, the name and address of the facility." The Draft Permit lists the location of the plant as "US 23, Greenup County, KY."[73] This might describe a location as far as 25 miles from the city of South Shore, as US 23 is within Greenup County lines approximately 25 miles southeast of South Shore, around Flatwoods, KY. This ambiguity regarding location does not give Kentucky residents adequate information about whether the proposed facility will located near them, a factor which would likely be relevant in a resident's decision to comment on the Draft Permit. Because listing a multi-mile stretch of country road does not qualify as an "address" per the terms of 401 KAR 52:100 § 5(2), the Draft Permit fails to satisfy public notice requirements.

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[68] *See* 42 U.S.C. § 7661c(a) and (c); 40 C.F.R. § 70.6(c)(1); 401 KAR 51:055.
[69] *See* Draft Permit, at 6.
[70] *See* Draft Permit, at 12. ("Compliance with the BACT determination for SO2 emissions shall be demonstrated by monitoring the sulfur content of the coal during normal operations.")
[71] *See* Draft Permit, at 13. The SunCoke Plant will emit PM, PM10, PM2.5, CO, VOC, SO2, and GHGs in significant amounts for PSD\BACT purposes.
[72] *See* 401 KAR 52:020 § 25.
[73] Cite to page # in permit.

The second flaw with the Draft Permit's public notice is its failure to list the degree of increment consumption. The Draft Permit is required, under 401 KAR 52:100 § 5(10), to include "the degree of increment consumption expected to occur" from the construction of a new or modified source. This requirement applies to both Class I and Class II increments.[74] The Draft Permit reports the *cumulative* increment consumption from all new sources in the region, but does not provide the degree of increment consumption expected to occur with respect to this project. The increment consumption referenced by 401 KAR 52:100 §5(10) is project-specific, since it applies to "permits subject to review under [PSD regulations]," and those permits are reviewed on an individual, project-specific basis. The Draft Permit's region-wide increment consumption reporting thus fails to comply with the public notice requirement listed in 401 KAR 52:100 § 5(10).

VII. Conclusion

For all the above reasons, the Draft Permit is deficient and does not meet CAA requirements. Consequently, the permit application must be denied pending compliance with all legal requirements.

Respectfully submitted,

Laurie Williams
Associate Attorney
Sierra Club
50 F Street, NW, Eighth Floor
Washington, DC 20001
(202) 548-4597
laurie.williams@sierraclub.org

Ethan Barnes
Legal Fellow
Sierra Club
50 F Street, NW, Eighth Floor
Washington, DC 20001
(202) 650-6074
ethan.barnes@sierraclub.org

[74] *See* 401 KAR 51:017 § 2. 401 KAR 51:017 is incorporated by reference in 401 KAR 51:100.

Commonwealth of Kentucky
Division for Air Quality

COMMENTS AND RESPONSE

ON THE STATEMENT OF BASIS

ATTACHMENT 6

SESS Response to Sierra Club Comments on SunCoke Energy South Shore Draft Construction and Operating Permit V-13-007, Plant ID 021-089-00047, Agency Interest No. 105793

Patch III – Next Page Starts New Batch

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SunCoke Energy

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Permit Review Branch
Division for Air Quality

David J. Schwake
Director, North America
Business Development

SunCoke Energy, Inc.
1011 Warrenville Road
Suite 600
Lisle, IL 60532
630-824-1000 Phone
630-824-1001 Fax

February 6, 2014

Mr. James Morse
Division for Air Quality
Kentucky Department for Environmental Protection
200 Fair Oaks Lane, First Floor
Frankfort, Kentucky 40601-1134

RE: Response to Sierra Club Comments on SunCoke Energy South Shore Draft Construction and Operating Permit

Permit:	V-13-007
Agency Interest:	105793
Activity:	APE20120001
Source ID:	21-089-00047

Dear Mr. Morse:

I am writing in response to comments submitted on behalf of the Sierra Club regarding the Kentucky Division for Air Quality ("KDAQ") draft Clean Air Act Title V Construction/Operating Permit No. V-13-007 ("Draft Permit" or "Permit") for the SunCoke Energy South Shore ("SESS") Coke Manufacturing Plant ("SESS Plant" or "Plant").

Kentucky's Prevention of Significant Deterioration ("PSD") program as codified in its State Implementation Plan ("SIP") is approved by the U.S. Environmental Protection Agency ("EPA"). *See* 40 C.F.R. § 52.923. Permitting decisions rendered by a duly authorized state agency such as KDAQ are entitled to deference, and are subject to challenge only if the decision was "without support of substantial evidence on the *whole* record" or was "arbitrary, capricious, or characterized by abuse of discretion." *See* KY. REV. STAT. ANN. § 13B.150(2) (emphasis added); *500 Assocs. v. Natural Res. & Envtl. Prot. Cabinet*, 204 S.W.3d 121, 132 (Ky. Ct. App. 2006); *Arkansas v. Oklahoma*, 503 U.S. 91, 113 (1992); *Chevron v. NRDC*, 467 U.S. 837 (1984).

As explained below, many of Sierra Club's comments are readily answered through a careful review of the complete administrative record, including SESS's permit application from December 10, 2012 ("Permit Application") and SESS's February 22, 2013 response to KDAQ's technical notice of deficiency ("NOD Response"). These documents were available for inspection as indicated in the Air Quality Permit Notice ("Public Notice") for the Draft Permit. *See* Ex. A (Air Quality Permit Notice, The Greenup County News-Times, Dec. 26, 2013, Page B9 ("Paper copies of the draft permit and relevant supporting information are available for inspection by the public during normal business hours at [KDAQ and Greenup County Public Library].")). Other comments by Sierra Club are the result of Sierra Club's misunderstanding SESS Plant operations and its concomitant misapplication of numerous regulatory provisions. SESS provides the following detailed responses to the comments submitted by Sierra Club. SESS has grouped the comments into general categories and responded to each category.

SunCoke Energy

I. The SESS Plant Will Not Contribute To Multiple NAAQS Violations.

Comment No. 1: Sierra Club claims that the Draft Permit fails to comply with sections of the Clean Air Act ("CAA") and Kentucky regulations prohibiting the construction of a new source unless emissions from the facility will not cause or contribute to air pollution in excess of any national ambient air quality standard ("NAAQS"). According to Sierra Club, based on Table 9 in the Draft Permit's Statement of Basis ("SOB"), the modeled 1-hour sulfur dioxide ("SO_2") concentration without the SESS Plant is 1333.0 $\mu g/m^3$ and 1393.11 $\mu g/m^3$ with the Plant, allegedly violating the 1-hour SO_2 NAAQS of 196.5 $\mu g/m^3$. In addition, Sierra Club claims that the modeled 24-hour particulate matter ("PM") less than 10 microns ("PM_{10}") concentration will rise from 256.3 $\mu g/m^3$ to 291.3 $\mu g/m^3$, and the 24-hour PM less than 2.5 microns ("$PM_{2.5}$") concentration will rise from 129.2 $\mu g/m^3$ to 148.5 $\mu g/m^3$ when the Plant is operating. These figures allegedly violate the 24-hour PM_{10} NAAQS of 150 $\mu g/m^3$ and the 24 hour $PM_{2.5}$ NAAQS of 35 $\mu g/m^3$, respectively. *See* Sierra Club Comments at 1-3 (Jan. 27, 2014) ("Comments").

Response No. 1: Sierra Club grossly mischaracterizes the data presented by SESS in Table 9 of the SOB. Sierra Club states that "[t]he modeled 1-hour SO_2 concentration *without* the SunCoke Plant is 1333.0 $\mu g/m^3$, which is above the NAAQS threshold by nearly seven fold. If the SunCoke Plant is built, the modeled concentration will rise to 1393.11 $\mu g/m^3$." Comments at 2 (emphasis in original). However, Table 9 unambiguously depicts 1333.0 $\mu g/m^3$ as the 1-hour modeled concentration of SO_2 *with* the SESS Plant and other facilities in the modeled area. Sierra Club therefore is incorrect when it states that the 1333.0 0 $\mu g/m^3$ figure represents SO_2 concentrations "*without* the SunCoke Plant." Further, Table 9 unambiguously depicts 1393.11 $\mu g/m^3$ as the cumulative modeled concentration when adding the modeled concentration to the *background level* of 60.11 $\mu g/m^3$. Sierra Club is therefore incorrect when it states that the modeled concentration is rising 60.11 $\mu g/m^3$ "[i]f the SunCoke Plant is built." 60.11 $\mu g/m^3$ is the background level of SO_2, as evident in Table 9. Sierra Club makes the same errors with respect to the 24-hour PM_{10} NAAQS and the 24 hour $PM_{2.5}$ NAAQS.

A new major source is not considered to cause or contribute to a violation of a NAAQS if the impact from the new source is less than the significant impact level ("SIL") where a modeled violation occurs. *See* 40 C.F.R. § 51.165(b)(2). SILs are numeric values appearing in EPA's regulations that may be used to evaluate whether a proposed major source or modification will cause or contribute to a violation of a NAAQS or PSD increment. *See* 72 Fed. Reg. 54112, 54138 (Sep. 21, 2007). Sierra Club's disregard for the concept of SILs is incorrect as a matter of law, and would prevent construction of new sources in most parts of the country. Modeling numbers are highly conservative and do not form the basis as to whether a NAAQS will actually be exceeded.

SESS's air dispersion modeling demonstrates compliance with the NAAQS and PSD Class II increment requirements in accordance with federal and state guidelines. As shown in

Table 9 of the Draft Permit's SOB, the contribution of the SESS Plant to all modeled concentrations of pollutants is either below SILs or does not result in a NAAQS violation. Table 9 contains a column clearly labeled "Project Contribution to Cumulative Impact greater than NAAQS ($\mu g/m^3$)." That column demonstrates that the contribution of the Plant's SO_2 (1-hour), PM_{10} (24-hour), and $PM_{2.5}$ (24-hour and annual) emissions to modeled exceedances of the NAAQS are below SILs. For example, the cumulative modeled 24-hour PM_{10} value of 291.3 ug/m^3 at a certain location is above the NAAQS of 150 ug/m^3. However, the impact from SESS at that location was less than the SIL (5 ug/m^3) and therefore is not considered to contribute to a violation of the NAAQS. This explanation applies to all the examples cited by Sierra Club. For pollutants that are not modeled to exceed the NAAQS when accounting for modeled concentrations plus background levels, SESS need not rely upon the SILs to demonstrate NAAQS compliance. For example, the annual cumulative modeled concentration of nitrogen dioxide ("NO_2") is 26.42 $\mu g/m^3$, which is below the NAAQS of 100 $\mu g/m^3$. Therefore, Table 9 does not show whether the contribution of NO_2 to a modeled NAAQS exceedance is below the NO_2 SIL of 1.0 $\mu g/m^3$; there is no modeled exceedance. Consequently, the SESS Plant will not cause or contribute significantly to a modeled violation.

II. The Emission Limits In The Draft Permit Do Not Fail To Satisfy BACT Requirements Of The CAA.

Comment No. 2: Sierra Club claims that KDAQ utilized a flawed process in making a best available control technology ("BACT") determination that resulted in emission limits that are much weaker than "maximum achievable standards." In particular, Sierra Club compares the SESS Plant's emission limits of 1.0 lb/ton nitrogen oxides ("NO_x") and 0.04 lbs/ton VOC with the emission limits of the Nucor Steel permit of 0.071 lbs/ton NO_x and 0.035 lb/ton VOC referenced in the SOB. *See* Comments at 3-4.

Response No. 2: Sierra Club repeatedly focuses on the terms "maximum" and "achievable" in the BACT definition, yet ignores the BACT definition's requirement to account for "energy, environmental, and economic impacts and other costs." *See* 42 U.S.C. § 7479(3). In doing so, Sierra Club conflates BACT with the lowest achievable emission rate ("LAER") requirement for nonattainment areas; unlike BACT, LAER does not permit consideration of "energy, environmental, and economic impacts and other costs." Sierra Club's reliance on out-of-context quotes from the 1990 EPA New Source Review Workshop Manual ("NSR Manual") to suggest otherwise is misplaced, as the NSR Manual is only a draft document, and, in any event, does not contravene the statutory mandate to account for these considerations. *See United States v. EME Homer City Generation, L.P.*, 727 F.3d 274, 280 (3d Cir. 2013) ("Whereas BACT factors in a limited cost-benefit analysis, LAER requires sources to use whatever technology achieves the lowest emission rate contained in a SIP or possible in practice, regardless of costs.").

Moreover, when an emission limitation representing BACT is prescribed by an agency, it need not "reflect the highest possible control efficiency achievable by the technology on which the emissions limitation is based." *See In re Masonite Corp.*, 5 E.A.D. 551, 560 (EAB 1994). An agency has discretion to base the limitations on control efficiency that is lower than the optimal level. *See id.* at 560-61 ("[A] permitting authority must be allowed a certain degree of discretion to set the emissions limitation at a level that does not necessarily reflect the highest possible control efficiency, but will allow the permittee to achieve compliance consistently.").

Sierra Club does not explicitly provide a different set of emission limits that should have been imposed, or state that the draft limits should have been based on different control technologies than those utilized in determining BACT for the SESS Plant. Rather, Sierra Club implies that the emission limits of the SESS Plant should not be set at a higher level than those in the Nucor Steel permit. However, Sierra Club cannot and does not explicitly assert that Nucor Steel's limits are appropriate for the SESS Plant because the proposed Nucor Steel facility has not been built, and the emission limits in the Nucor Steel permit have not been demonstrated in practice. For this reason, the emission limits in the Nucor Steel permit are not BACT.

The SESS Plant will actually be the most controlled coke plant existing in the United States. In any case, when conducting a BACT analysis, the permitting agency must make a case-by-case determination based on site-specific and source-specific characteristics, such as the type of fuel that will be used, the type of source, and geographic considerations; taking into account these considerations does not "yield a single, objectively correct BACT determination." *Alaska Dep't of Envtl. Conservation v. EPA*, 540 U.S. 461, 488-491 (2004) (holding EPA's role in reviewing state agency's BACT determination is limited to ensuring that it is based on "reasoned analysis" and not contrary to state agency's own findings).

Several sources of information were evaluated to determine which control technologies or techniques should be considered in the BACT analysis for the SESS Plant. The following resources were consulted by SESS:

- EPA's Air Pollution Control Cost Manual (EPA 2002);
- EPA Office of Air Quality Planning and Standards' maximum achievable control technology ("MACT") developmental data;
- 40 C.F.R. Part 63, Subpart CCCCC, National Emission Standards for Hazardous Air Pollutants ("NESHAP") for Coke Ovens: Pushing, Quenching, and Battery Stacks;
- 40 C.F.R. Part 63, Subpart L, NESHAP for Coke Oven Batteries;
- EPA's Reasonably Available Control Technology ("RACT")/BACT/LAER Clearinghouse ("RBLC");
- EPA white papers on greenhouse gas ("GHG") control measures;
- Permits for similar sources issued in other states; and
- Applicant knowledge.

SunCoke Energy

Comment No. 3: Sierra Club claims that the BACT analysis failed to follow the five-step, top-down process typically applied by KDAQ. In particular, Sierra Club claims that KDAQ eliminated a wet scrubber as BACT for SO_2 based exclusively upon consideration of incremental cost. *See* Comments at 6-7.

Response No. 3: Sierra Club is simply incorrect; a five-step, top-down BACT analysis was performed and documented. SESS's Permit Application contains a ninety-three page analysis of potential control technologies. *See* Section 5.0 (Best Available Control Technology Analyses). This analysis details the top-down BACT analysis utilized.

For reference, below is the table of contents pulled from the Permit Application which details the BACT considered for all relevant emissions at the Plant, including the BACT for NO_x and SO_2, which Sierra Club appears particularly concerned about. *See* Comments at 6-7.

SunCoke Energy

5.6.3 Best Available Control Technology for Nitrogen Oxides
5.7 Greenhouse Gases from Coking and Related Activities
5.7.1 Coking
5.7.2 Pushing
5.7.3 Best Available Control Technology for Greenhouse Gases
5.8 Hydrochloric Acid from Coking and Related Activities
5.8.1 Control Technology Evaluation for Hydrochloric Acid
5.9 Mercury from Coking and Related Activities
5.9.1 Control Technology Evaluation for Mercury
5.10 Summary of Proposed Best Available Control Technology for Significant Emission Units
5.11 Summary of Proposed Best Available Control Technology for Other Activities
5.11.1 Initial Startup
5.11.2 Waste Heat Stack Lid Testing
5.11.3 Other Activities

See Permit Application, at 5-1–93.

With respect to Sierra Club's comment that a wet gas scrubber ("WGS") was eliminated from consideration based solely on incremental cost, Sierra Club is incorrect. The reasons supporting a circulating dry scrubber ("CDS") in lieu of a WGS include:

- A WGS requires the addition of a wastewater treatment plant, resulting in wastewater discharge and associated water pollution.
- The WGS is less effective than a CDS/baghouse system at the removal of PM (and thus metals) as well as sulfuric acid mist ("H_2SO_4"), resulting in higher emissions of PM and H_2SO_4.
- The WGS is less efficient and utilizes more energy than a CDS, resulting in higher GHG emissions.
- More expensive metallurgies are required to handle the corrosive nature of the WGS.
- A WGS can cause ionic mercury to become vapor phase mercury, resulting in higher mercury emissions.
- There is an additional cost of $28,000 per ton of SO_2 based on the incremental removal from a WGS instead of a CDS (assuming a WGS could actually achieve more reduction, which has not been proven).

The following citations from the Permit Application and KDAQ's SOB demonstrate that there were multiple reasons for choosing a CDS in lieu of a WGS.

For example, the Permit Application at Section 5.4.1.6 (Best Available Control Technology for Coking) gave multiple reasons for choosing the CDS over the WGS:

In terms of SO_2 removal efficiency, the two top control options are the CDS and the wet scrubber. CDS systems have been demonstrated to consistently achieve >95% SO_2 control efficiency at coal-fired power plants. Although CDS systems have been known to achieve up to 98% control efficiency in boiler applications, their performance or ability to achieve such high removal in a heat recovery coke application is unknown. A wet scrubbing system is considered theoretically feasible for SESS, but has never been used in practice at a coke plant because of the inherent environmental and operational advantages of dry scrubber systems. While wet scrubbers have also been known to achieve up to 98% removal in boiler applications, the actual control efficiency has not been evaluated at a coke plant (since such a system has not been installed for similar applications) and as such may not provide any additional SO_2 control than the CDS option. Regardless, the two technologies were compared based on their energy, environmental, and economic impacts. The selection criteria established conclude CDS (or equivalent performing technology) as BACT for the SESS coking process as supported by the following:

- A CDS (or equivalent performing technology) will provide high SO_2 removal without generating wastewater. Wet scrubbing requires addition of a wastewater plant and water effluent discharge from the plant.
- Compared to a wet scrubber, CDS followed by a baghouse is very effective at minimizing emissions of fine particulate ($PM_{2.5}$), hazardous metals, and H_2SO_4.
- A wet scrubber requires more energy for operation compared to a CDS, indirectly leading to higher GHG emissions.
- Incremental cost of SO_2 removal (wet scrubber versus CDS) is on the order of $28,000/ton (based on the cost of two identical wet versus two identical CDS systems).

Appendix G [of the Permit Application] includes a detailed BACT analysis and supporting documentation.

For these reasons, the wet scrubber option was rejected for this application even though the technology is theoretically feasible. With a CDS (or equivalent performing technology), PM emissions will be controlled to a level of 0.005 gr/dscf, PM_{10} will be controlled to 0.011 gr/dscf, and $PM_{2.5}$ emissions will be controlled to a level of 0.0085 gr/dscf at SESS. In addition, the higher removal of H_2SO_4 (expected to be at least 98%) removes a more direct $PM_{2.5}$ precursor. With these considerations, a CDS system, with a design removal efficiency of up to 96%, was selected as BACT for the primary system to control SO_2 and $PM/PM_{10}/PM_{2.5}$. The level of control is

> more stringent than recent BACT determinations listed in the RBLC database.

Additionally, the Permit Application at Section 5.4.1.3 (Wet Scrubber) explains as follows:

> Some disadvantages for using wet scrubbing techniques in many applications are the requirement to treat wastewater, materials must be constructed from expensive alloys to resist corrosion, and energy use is much higher.

Additionally, KDAQ's SOB explains:

> The Wet Scrubber (WS) uses a more liquid slurry (approximately 10 percent lime or limestone in water) to treat the flue gas stream. The WS systems are designed for efficiencies of >95 percent removal of SO_2, but are more complex, require a larger footprint, use more energy than the CDS, and produce a waste requiring disposal. In addition, this type of system may cause ionic mercury to become mercury vapor (DOE 2008, An Update on DOE/NETL's Mercury Control Technology Field Testing Program), making collection difficult (Srivastava et. al., "Preliminary Estimates of Performance and Cost of Mercury Control Technology Applications on Electric Utility Boilers." Journal of the Air & Waste Management Association 51 (2001): 1461), and it has less ability to remove acid mists than other SO_2 control systems ("Flue Gas Desulfurization Technology Evaluation, Dry Lime vs. Wet Limestone FGD", National Lime Association, Sargent and Lundy, 2007).

Comment No. 4: Sierra Club commented that "in determining BACT for NO_x, the Division performed an inadequate analysis of control technology feasibility . . . The draft permit cites no unique characteristics in the SunCoke design that are not present in other sites which use [selective non-catalytic reduction ("SNCR")] to control NO_x emissions." Furthermore, Sierra Club's comments state "[b]eyond the SNCR and [Hot-Side Selective Catalytic Reduction ("SCR")], the Division eliminated several additional NO_x control devices for impermissible reasons. The Division excluded control strategies because the 'technology requires a wastewater treatment plant,' or '[the technology] has only been demonstrated with small to medium-sized boilers.' According to the Sierra Club, neither of these reasons provides an adequate justification for rejecting control technologies; the fact that a control technology might require design alterations does not mean that the technology is infeasible. Moreover, these technologies have been widely used during the combustion of coal. Partial combustion of the *same coal* does not present unique technical challenges that are grounds for excluding these technologies." *See* Comments at 7-8 (emphasis added).

Response No. 4: Contrary to Sierra Club's assertions, there are several distinct characteristics of coke ovens that preclude the use of control technologies utilized for the combustion of coal. As explained in the Permit Application at Section 5.6 (Nitrogen Oxides from Coking and Related Activities):

> As previously stated, the types of air pollution control systems used for coal-fired utility boilers could generally be used for heat recovery coke ovens. However, differences in the nature of the process and flue gas characteristics prevent direct comparison of performance. The heat recovery flue gas is unique. It does not contain the light coal fly ash of a coal-fired boiler. The particulate loading in heat recovery coke oven flue gases is low due to their inherently excellent combustion efficiency. However, with little alkaline fly ash to adsorb HCl, chloride salts form in air pollution control devices. Coal fly ash is light and stays suspended, whereas calcium chloride is sticky and easily forms deposits. The air pollution control system for heat recovery coke ovens must be operated to minimize deposition of chloride salts. Also, coke ovens cannot be shut down without causing severe damage to the ovens. This is not the case with utility boilers, which can be routinely shut down if problems develop in the air pollution control system.

Additionally, the volatile matter (typically 25% of the coal) is oxidized in SESS's heat recovery ovens to provide heat for the coking reaction, while most of the contaminants which can lead to fouling will remain in the coke oven flue gas. In contrast, in a coal fired boiler, 100% of the coal (which includes volatile matter) is combusted, which makes for a considerably higher production of gas. Therefore, SESS's ovens emit far less flue gas per ton of coal, but SESS's coke oven flue gas contains higher concentrations of contaminants and does not contain significant quantities of alkaline fly ash (which can absorb contaminants). For these reasons, Sierra Club's assertion that SESS's coke oven flue gas and design conditions are not unique is incorrect.

Additionally, Sierra Club's statement that the Plant will be practicing "partial combustion of the same coal" as coal-fired boilers is an incorrect statement. Coal-fired boilers target full combustion of *thermal* coal in an excess oxygen atmosphere whereas the metallurgical coking process utilizes *metallurgical* coals at sub-stoichiometric oxygen levels. As previously indicated, in SESS's metallurgical coking process, only the volatile matter in the coal is oxidized; in a coal fired boiler, the coal itself is combusted. Therefore, the process of coal fired boilers and coking are distinctly different, and the SNCR is not appropriate for controlling NO_x emissions from coke ovens.

Because SESS's heat recovery coke plant is inherently different from coal-fired boilers, SNCR was not chosen as an add-on control for NO_x for reasons including:

- Heat recovery flue gas is unique as the contaminant concentrations are higher than that of coal fired boilers, and it does not contain high amounts of alkaline fly ash which can absorb some contaminants that would create salts and cause severe fouling.

- At SESS, the low NO_x level of 70 ppm (from the inherent design of staged combustion) causes the control efficiency of SNCR to be estimated at less than 25% or a <20 ppm reduction.
- The temperature range of SNCR application falls within at least a 2,500 foot run of hot duct sections, which are subject to continuously variable conditions. Under such an extensive and changing run, injection of ammonia at the correct numerous locations would be impracticable as well as a significant safety concern.

The Permit Application at Section 5.6.1.3 (Selective Non-Catalytic Reduction) further explains why SNCR is not appropriate for controlling NO_x emissions from coke ovens:

> Three difficulties associated with using SNCR in the heat recovery process involve temperature, initial NO_x level, and fouling.
>
> The biggest challenge in the implementation of SNCR is the effect of temperature. The SNCR process operates over a relatively narrow temperature range. Figure 5-4 shows how a boiler could be configured with multiple injection locations so that ammonia or urea can be added at an appropriate temperature. Note also that, because of the large space in a boiler, there will be adequate residence time at the ideal temperature. The required temperature window is 1,600–2,200°F (the most effective range is 1,800–2,100°F). Above these temperatures ammonia begins to react with oxygen rather than NO_x (i.e., it is no longer a selective process). At even higher temperatures, more NO_x will be formed from nitrogen in the reagent. Below the ideal temperature range, no reaction will occur and ammonia slip will increase, leading to fouling in the HRSGs. The oven crown and sole temperatures would not be appropriate locations to add ammonia or urea because the temperatures are generally higher. The temperature in the common tunnel and hot duct to the HRSG varies from 1,800°F to 2,400°F. So at times the temperature would be in the correct range and at times above the range. However, locating this narrow temperature window in the 2,500 ft of common tunnel would be extremely difficult, especially if this temperature region moves within the tunnel as process conditions change.
>
> In contrast to an SNCR system at a boiler, an SNCR system for heat recovery coke ovens would have to be instrumented with a system that could monitor the temperatures throughout the 2,500 ft of common tunnel and hot ducts for the HRSGs and have many injection locations so that reagent could be injected where needed. This contrasts with an SNCR application at a boiler where the injection locations would be close together. To the best of SESS' knowledge, the type of SNCR system required for an application like heat recovery coke ovens has never been demonstrated.

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The second and equally big factor in the effectiveness of SNCR is the low NO_x levels in the [coke oven] flue gases. Higher initial NO_x levels ($\geq$200 ppm) result in removal efficiencies of $\geq$40%. The achievable NO_x reduction markedly decreases as the initial NO_x in the [coke oven] flue gases drops. If the initial NO_x levels are <100 ppm, laboratory testing has shown that only 20–25% reduction can be achieved. In fact, recent SNCR demonstration projects conducted by FERCo on two coal-fired utility boilers that had initial NO_x levels under 100 ppm achieved <20% NO_x reduction (see Appendix B [in the Permit Application]). Additionally, the same SNCR limitations are described in the EPA Air Pollution Cost Control Manual (EPA 2002). Figure 1.5 in Section 4 of this EPA document shows that, for a 70 ppm initial NO_X level (comparable to expected NO_X levels at SESS), less than 25% NO_X reduction is expected at 2,000°F (temperature in the common tunnel at SESS). The same reference was used in a more recent EPA Office of Air Quality Planning and Standards document (EPA 2007) on NO_X emissions from new cement kilns. It is evident that EPA also accepts the limitation of an SNCR to remove NO_X at low initial NO_X levels. Therefore, the low initial NOx level in the [coke oven] flue gases at SESS (70 ppm at 8% oxygen) renders SNCR an ineffective control option.

A third challenge to implementing SNCR to the heat recovery process is the high likelihood of fouling. Any ammonia slip from the SNCR process will result in the formation of ammonium sulfates and ammonium bisulfates (ABS), which are known to cause plugging of downstream equipment. In a coal unit, the flue gas contains a fairly high loading of fly ash particulates. As the ABS forms, it can either deposit on the heat exchanger surfaces or onto the fly ash. With high particulate loadings in a coal-fired boiler, the ABS will likely end up on the fly ash rather than on the heat exchanger. The heat recovery coke oven flue gas contains much lower particulate loading. Therefore, deposition and fouling in the HRSG may be severe. ABS formation and related fouling is discussed in more detail under Selective Catalytic Reduction (SCR) in Section 5.6.1.4 [in the Permit Application].

The particulate material in the heat recovery coke oven gases is acidic and contains condensable metal salts with a demonstrated tendency to cause fouling. Fouling deposits have been found in all three temperature zones (superheater, evaporator, and economizer) of the HRSGs at other SunCoke plants. These fouling deposits have resulted in frequent boiler tube corrosion and tube replacement in all three sections of the HRSGs. Despite installation of special soot blowers to deal with this, experience at Haverhill North Coke Company has shown that the HRSGs should be shut down for maintenance and cleaning twice a year. The use of SNCR would add ABS, which also has a high fouling potential. This combination is likely to cause more fouling, which would lead to the need for more cleaning and maintenance.

SNCR is not technically feasible and has never been used with the heat recovery coking process because of the low NO_x levels in the [coke oven] flue gases, potential for increased [heat recovery steam generator ("HRSG")] fouling, the difficulty of determining an appropriate injection location, and the complexity that would be required to safely deliver the reagent throughout the 2,500 ft of common tunnel and hot duct.

The Permit Application at Section 5.6.1.4 (Hot-Side Selective Catalytic Reduction) also explains the difference between boilers and coke plants for purposes of utilizing SCR:

When used with coal-fired boilers, SCRs have mainly been applied to electric utilities and large industrial boilers ranging in size from 1,300 to 8,000 MMBtu/hour (RBLC database, November 2010). Since boiler outlet temperatures are usually much cooler than 700°F, SCRs are often installed between the economizer and air heater. This ensures that the gases entering the SCR reactor are in the appropriate temperature range. An economizer bypass can be used to divert part of the hot flue gas around the economizer to bring the temperature into the optimum range. The temperature of the gas stream is cooled in the air heater, downstream of the SCR reactor, to the desired outlet temperature. Figure 5-5 [in the Permit Application] is a schematic of an SCR system in a boiler. This configuration is normally referred to as a hot-side SCR.

The types of HRSGs needed at SESS consist of four sections: water wall, superheater, evaporator, and economizer. The economizer in these types of HRSGs is designed to cool the [coke oven] flue gases to 350°F compared to the typical large boiler or heater with economizer outlet temperatures closer to the 650–750°F range. At 350°F, the [coke oven flue] gas temperature is outside the range where SCR would be effective. The HRSGs are relatively small units (<500 MMBtu/hour) designed to produce steam from waste heat. Unlike large utility boilers with economizers and air heaters, they do not contain large sections within the unit where the temperature is in the range where SCR can be used. The temperatures in the three sections of the HRSG are typically in the following ranges: 1,400–1,900°F in the superheater, 850–1,400°F in the evaporator, and 375– 850°F in the economizer. Therefore, to utilize the SCR, the entire HRSG would have to be redesigned to provide the appropriate temperature window.

Another major factor that impacts implementation of SCR for a heat recovery process is the availability of a suitable catalyst. In any SCR application, flue gas constituents degrade the activity of the catalyst over time. Different flue gas types have differing impacts on the catalyst deactivation rates (see Appendix B [of the Permit Application]). So, in order to design the catalyst (selection of a proper pitch), the supplier needs to know the fouling tendency and the fouling rates of the particulates. This information is crucial to selecting a catalyst volume and consequently the size of the SCR reactor. There is experience using SCR on coal-fired boilers and a catalyst can be readily designed for those applications. However, the flue gas characteristics of the waste gases from coke oven batteries are different from coal-fired boilers. For example, the heat recovery coke oven flue gas does not contain the light coal fly ash of a coal-fired boiler. There are no known SCR applications at heat recovery coke plants to date. Therefore, in order to select the right kind of catalyst and to determine other critical design parameters for a heat recovery coke application, the catalyst supplier would have to conduct pilot tests to gain the necessary information.

A preliminary analysis of fouling deposits in the HRSGs at other SunCoke plants has indicated the presence of SCR catalyst poisons in the [coke oven] flue gas. Oxides, sulfates, and chlorides of potassium, silica, iron, sodium, and aluminum have been found in these deposits. One of the well-known mechanisms of catalyst deactivation is where alkaline metals chemically attach to active catalyst pore sites and cause blinding. Sodium and potassium are of prime concern especially in their water-soluble forms, which are mobile and penetrate into the catalyst pores. Research on SCR catalyst deactivation indicates that potassium in the form of both chloride and sulfate is a strong poison for SCR catalysts (Zheng, Jensen, & Johnsson 2004). In order to obtain reliable data for catalyst design, such pilot tests could take up to 2 years (see Appendix B [of the Permit Application]).

Additionally, as with the SNCR process, ammonia slip and increased fouling of HRSGs from ABS are still a challenge with SCR. Downstream of the SCR unit, SO_3 in the [coke oven] flue gas will react with residual ammonia in the gas stream to form ABS. The ABS will condense into a sticky liquid as the [coke oven] flue gas temperature decreases to about 450°F in the economizer section of the HRSG. Testing by FERCo on a utility flue gas stream has demonstrated that a flue gas containing nominally 6–8 ppm of NH_3 and 10 ppm of SO_3 approximately doubled the pressure drop across the air preheater due to ABS formation, indicating the severity of ABS-related fouling. Recent assessments of formation and deposits of ABS (in the utility industry) have uncovered that the extent of air preheater fouling problem in the United States is wider and more serious than expected. Revised air preheater fouling criteria are now specifying that SO_3 levels lower than 2–3 ppmv and NH_3 levels lower than 1–2 ppmv are required to avoid air preheater fouling by ammonium salts (Sarunac 2011). Unfortunately, both NH_3 and SO_3 are present in the [coke oven] flue gas downstream of the SCR. Ammonia slip is practically an unavoidable consequence of injecting ammonia or urea into the [coke oven] flue gas for NO_x reduction. Additionally, the SCR catalyst is also responsible for increased SO_2 to SO_3 conversion, which further aggravates the fouling problem. At SESS, [coke oven] flue gases entering the HRSGs could contain up to 60 ppm of SO_3. Therefore, there is a very high potential for significant fouling and corrosion of the HRSGs. An additional source of fouling and corrosion would be ammonium chloride, which could be produced due to high concentrations of chlorinated compounds in coke oven exhaust.

Soot blowing is one of the most common methods of controlling fouling and corrosion of heat transfer surfaces. Other methods include water washes, increasing cold end temperature, reducing SO_3 concentration in the flue gas, and modification of the heat transfer equipment. In case of fouling caused by ABS deposits, frequent water washes are usually needed; other techniques mentioned above are either ineffective or infeasible for certain applications. Lately, shock wave cleaning systems have been used in boiler applications in the form of sonic pulse or acetylene-based explosion generators to control fouling of the boiler tubes without having to take the boiler offline. In another similar controlled detonation technique (bang and clean method), a lance is introduced into the boiler near the area to be cleaned. At the end of the lance, a heat-resistant bag is inflated with an explosive medium containing commercially available gases and water, and brought to a controlled detonation by remote control. The controlled detonation propagates into a shock wave, which impacts directly on surfaces to be cleaned, but also creates vibrations on the boiler's walls and tubes. The shock wave plus the vibrations causes fouling, like ashes and slag, to fall off the surfaces. However, it is not clear if these shock wave systems are effective at controlling ABS because ABS is hygroscopic, corrosive, sticky, and difficult to remove. When dealing with ABS fouling, water-washing is often the only effective means of cleaning. This means significant downtime of the HRSGs because outage associated with water washes could last 30 hours or more. Additionally, field experience has shown that overreliance on water-washing may increase surface corrosion, which, in turn, will increase fouling rates (Sarunac 2011).

In short, hot-side SCR technology is considered technically infeasible for heat recovery coke plants due to the lack of a zone with appropriate temperature to install SCR in this type of relatively small and simple HRSG, lack of design data for catalyst, and the potential for increased HRSG fouling due to ABS formation.

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Additionally, the Permit Application at Section 5.6.1.5 (Tail-End Selective Catalytic Reduction) states:

> In a tail-end configuration the SCR reactor is placed downstream of all air pollution control equipment installed on a unit. Figure 5-6 is a schematic of a tail-end SCR (TESCR) system in a boiler application. The air pollution control equipment removes most flue gas constituents detrimental to SCR catalyst before it enters the SCR reactor. However, the potential for ABS formation and related fouling and corrosion problems still exists for equipment downstream of the SCR as discussed below.
>
> Since the flue gas temperature at the tail-end is below the range required for the ammonia/NO_x reaction, the flue gas needs to be reheated. A TESCR system typically uses a gas-gas heat exchanger and duct burner to reheat the flue gas to the optimum operating temperature required for the SCR. Heat from the flue gas exiting the SCR would be recovered in the gas-gas heat exchanger (to heat the incoming flue gas) before the cooled flue gas is exhausted to the stack. The flue gas exiting the SCR would contain ammonia (due to ammonia slip) and small amounts of SO_3 (due to oxidation of flue gas SO_2 inside the SCR) and would be cooled down from approximately 700°F to 200°F, providing the right temperature range for ABS formation previously described. Additionally, the small amounts of chlorides in the flue gas could form ammonium chloride, which is known to cause stress corrosion cracking. The effect of ammonium chloride on catalyst life and performance is also not known. All these factors make it difficult to predict the technical feasibility of TESCR at SESS especially since it has never been tried before at a heat recovery coke plant.
>
> Despite these questions over its technical feasibility, economic, energy, and environmental impact analyses were performed for a hypothetical TESCR to compare it with staged combustion, which is inherent to the coking process. The overall evaluation concluded that staged combustion remains BACT for the SESS coking process as supported by the following:
>
> - TESCR could potentially cause equipment corrosion and fouling problems from ammonium chloride and ABS formation.
> - TESCR will result in increased GHG, H_2SO_4, and ammonia emissions.
> - TESCR will consume additional energy due to reheat requirements and pressure drop across the unit.
> - Incremental cost of NO_X removal is nearly $14,000/ton for a new system. Operating costs will likely be much higher over time.

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Sierra Club further commented that "[t]he Division excluded control strategies because the 'technology requires a wastewater treatment plant,' or '[the technology] has only been demonstrated with small to medium-sized boilers.' Neither of these reasons provides an adequate justification for rejecting control technologies . . . ."

Contrary to Sierra Club's comment, there are several issues with Low Temperature Oxidation ("LTO") systems for add on control of NO_x at SESS including:

- The targeted control temperature range is less than 300°F with SESS's inlet temperature to the CDS at 385°F to 420°F to avoid acid dewpoint which causes severe corrosion on the low side to the high side regulated by proper operation of the CDS.
- For TriNOX the addition of a waste water treatment plant and waste water effluent stream.
- For TriNOX it is complimentary to a caustic scrubber not being used in this application.
- Typically the LTO systems are for high inlet NO_x concentrations in the >1000 ppm not the 70 ppm expected at SESS.
- Neither have been commercially demonstrated in this application or size of application.
- LoTOX would increase H_2SO_4 emissions and GHG emissions due to higher energy needs to generate ozone.

The Permit Application at Section 5.6.1.6 (Low Temperature Oxidation with Absorption) states:

> Low temperature oxidation (LTO) is a NO_x removal system that utilizes an oxidizing agent like ozone, injected into the flue gas stream to oxidize insoluble NO_x to soluble oxidized compounds. Both NO and NO_2 are relatively insoluble in aqueous streams. But, higher NO_x are highly water soluble and can be scrubbed with water as nitric and nitrous acids or with caustic solution as nitrite or nitrate salts. LTO systems are generally utilized for flue gas streams with temperatures below 300°F. At elevated temperatures, oxidation rate of NO is reduced, thereby rendering the LTO process ineffective. For SESS, this means that LTO systems would not be feasible upstream of the CDS where temperatures will be higher than 300°F. A discussion of the applicability of two major LTO systems (Tri-NOx® and LoTOx®) in a tail-end configuration at SESS is provided below.
>
> Tri-NOx®. This technology, commercialized by Tri-Mer Corporation, uses an oxidizing agent such as ozone or sodium chlorite to oxidize NO to NO_2 in a primary scrubbing stage. Then NO_2 is removed through caustic scrubbing in a secondary stage. Several process columns, each assigned a separate processing stage, are involved. One of the big drawbacks of this system is that the discharge will need to be treated in a wastewater treatment plant.

> This technology is designed to complement control systems that already include a caustic scrubber. Tri-NOx® is typically applied at small to medium-sized sources with high NO_x concentration in the exhaust gas (1,000 ppm NO_x) like nitric acid plants. NO_x concentrations in the [coke oven] flue gases at SESS will typically be around 70 ppm (at 8% oxygen). Further, it is not listed as a successfully demonstrated option in any RBLC determination. Therefore, Tri-NOx® is considered technically infeasible for SESS.
>
> LoTOx®. LoTOx® technology, commercialized by BOC gases, uses ozone to oxidize NO to NO_2 and NO_2 to N_2O_5 in a wet scrubber (absorber). The N_2O_5 is converted to nitric acid (HNO_3) in a scrubber and is removed with lime or caustic. Evaluations of LTO found that it has only been applied to small to medium-sized coal or gas-fired boiler applications, and has never been demonstrated on a large-scale facility (EPA 2005). For example, the current installations of LoTOx® are on sources with flue gas flow rates from 150 to 35,000 acfm, which is quite small compared to the SESS [coke oven] flue gas flow rates of up to 450,000 acfm. Therefore, the application of LTO would be more than an order of magnitude larger than the biggest current installation. For this reason, LoTOx® is considered unavailable for application to the SESS coke plant. Even for smaller sources where this technology could be applied, there are certain negative environmental, energy, and economic impacts: (a) the ozone that would be injected into the [coke oven] flue gas would react with the SO_2, converting it to SO_3, which could result in increased emissions of H_2SO_4; (b) ozone for LoTOx® is typically generated onsite with an electrically powered ozone generator, which means increased energy usage (especially for larger sources); and (c) since ozone is generated from pure oxygen, in order for LoTOx® to be economically feasible, a source of low cost oxygen must be available from a pipeline or onsite generation. LoTOx is considered an unavailable technology because it has never been demonstrated on a large-scale facility and even if scalable to bigger sources, the potential negative environmental, energy, and economic impacts make it an infeasible control option for SESS.

Additionally, the global summary consistent with the comprehensive top-down approach for BACT for NO_x is provided in the Permit Application at Section 5.6.3 (Best Available Control Technology for Nitrogen Oxides) as follows:

> This section summarizes the five step top-down methodology used in the BACT analysis for NO_x.
>
> Step 1: For coking, six NO_x control options were identified—staged combustion, [low-NO_x burners ("LNBs")], SNCR, hot-side SCR, TESCR,

and LTO with absorption. No add-on controls are feasible for charging and pushing.

Step 2: Among the six control options reviewed, only staged combustion was found to be technically feasible for this process. LNBs are not technically feasible for heat recovery coke ovens because the coal is not burned and there is no external fuel. Post-combustion controls are not feasible with the heat recovery coking technology. SNCR is not feasible due to the absence of a suitable location with the correct temperature window, low NO_x levels in the [coke oven] flue gases, and the high potential for increased fouling of the HRSGs. A hot-side SCR is not technically feasible due to the lack of design information in terms of catalyst life and fouling tendencies, the lack of a proper temperature window within the HRSGS to install the catalyst, and the potential for increased fouling of the HRSGs. TESCR was also considered to be theoretically feasible for this application. LTO absorption systems are considered an unavailable technology for SESS because they have only been demonstrated on small to medium sources that have high NO_x concentrations in the exhaust gases and are generally designed to complement control systems that already have a caustic scrubber.

Step 3: Staged combustion, which is inherent to the coking process, was determined to be a technically feasible option to control NO_x emissions. The only add-on control option hypothetically assumed to be feasible was TESCR. TESCR can typically achieve 60–90% NO_x reductions (http://www.netl.doe.gov/publications/proceedings/06/ecc/pdfs/Licata.pdf) depending on the inlet NO_X concentrations, [coke oven] flue gas temperature, and allowable ammonia slip.

Step 4: Staged combustion is an inherent part of the heat recovery process and will not result in any adverse environmental, energy, or economics impacts. TESCR comes with significant energy and environmental impacts. Therefore, to determine whether a hypothetical TESCR is BACT for this application, energy, environmental, and economic evaluations were performed.

Step 5: TESCR was rejected as BACT because of its (1) potential to cause equipment corrosion and fouling problems from ammonium chloride and ABS formation; (2) increased energy (and thus increased GHG), H_2SO_4, and ammonia emissions; (3) high energy impact and high cost (estimated capital of $40,600,000, an annual operation and maintenance cost of nearly $3,000,000, and cost effectiveness of nearly $14,000/ton of NO_X removed for a new system). Operating costs will likely be much higher over time.

Combustion controls to minimize NO_x from coking was selected as BACT. This technology can reduce the NO_x concentration to <120 ppm. Staged combustion will produce NO_x emissions equivalent to 280 lb/hour (or less) and 613.2 tons/year coal, which is approximately an average of 70 ppm at 8% oxygen.

The above discussion proves that a comprehensive approach was taken for a top down approach for BACT.

Comment No. 5: Sierra Club claims that startups and shutdowns are part of normal operation and emissions that occur during these periods must be included in the BACT analysis and limited in the Draft Permit. Sierra Club further claims that exemptions from startup and shutdown emission limits must be made on a pollutant-by-pollutant basis demonstrating how compliance with permit limitations is not feasible during startup and shutdown, and must take into account the extent to which control equipment for the different pollutants will continue to function during startup, shutdown, and malfunction. *See* Comments at 8-9.

Response No. 5: The Draft Permit contains work practice standards in lieu of numerical emission limitations for periods of startup because startup is a one-time, extraordinary event for which work practice standards are the only feasible way of controlling emissions, and the concept of shutdown, as generally understood, is inapplicable to coke ovens. SESS's heat recovery coke batteries are unique because once they have completed their initial commissioning, which requires heat up, dry out, and curing of the various refractories, the batteries are not capable of shutting down. Start-up is an exceptional one-time event and "normal operation" is defined as any time period following the initial commissioning start-up. No variance is required during normal operation (after the initial extraordinary one-time event commissioning) and, as indicated, the emissions limits of the permit apply.

As a result of the unique characteristics of heat recovery coke batteries, work practice standards (which require use of low sulfur coal and minimum practicable coal charge) have been established for the extraordinary, one-time startup period. Numerical emission limits are impracticable during start-up because pollution control equipment cannot be operated until a sufficient amount of coke oven flue gas is generated to sustain safe and reliable operation of the HRSGs and the circulating dry scrubbers. Work practice standards, including low-sulfur coal and low charge rates, are the only means to control emissions during startup, as explained below in further detail.

The South Shore heat recovery coke plant design is the most advanced design and environmentally friendly coke plant in the world. The design of this plant not only incorporates new technologies for HRSGs aimed at improved performance and reliability but also incorporates new circulating dry scrubber technology that employs an unmatched level of redundancy. The plant incorporates three 50% of full capacity HRSGs to allow for full capacity without venting should one of the three HRSGs require maintenance.

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Additionally, the design includes redundancy of the circulating dry scrubber to allow for maintenance at full operation without venting.

Additional detail on the extraordinary one time start up event can be found in the NOD Response:

> Initial startup of coke oven batteries is an exceptional one-time event. Once started up, a coke oven battery cannot be shut down without affecting its service life. The heat recovery coke ovens are constructed of silica bricks. The walls of the main coking chamber contain flues that allow the [coke oven] flue gas to pass from the main chamber to sole flues beneath the oven floor. The crown (roof) of the coking chamber is constructed of silica bricks laid in an arch. The common tunnel is located on top of the ovens, parallel to the length of the battery. The common tunnel is constructed of a steel shell that is lined with castable refractory. The weight of the oven crowns, the common tunnel, and the vent stacks is borne by the silica brick walls. Silica brick is used because it has a high melting temperature (3,100°F), it can withstand relatively high compressive loads when hot, it is volumetrically stable at the temperatures inside the heat recovery oven, and it can withstand either reducing (crown) or oxidizing (sole flue) atmospheres. It is resistant to thermal spalling as long as the temperature remains above approximately 1,100°F. Thermal spalling is the breaking of refractory from stresses that arise during repeated heating and cooling. At temperatures below 1,100°F, silica brick is highly susceptible to thermal spalling.

Initial heat-up is completed with natural gas burners with a bank of 60 ovens (2X30) out of the 120 ovens. As the initial heat up is completed with natural gas on the first 60 ovens the bürners are pulled and initial coal charges of 27 to 35 tons per oven begin. Once the first bank of 60 ovens is preliminarily heated with natural gas and shifted to coal the second bank of 60 ovens begins heat up with natural gas. This avoids natural gas supply limitations and resulting coke oven flue gas limitations during start up. The first bank of 60 ovens works its coal charge up to the initial startup limit of 42.5 tons per oven charges (instead of the designed 50 tons per oven charges) utilizing coal with an initial startup limit of 1.1 wt% sulfur (instead of the permitted 1.3 wt% coal sulfur during normal operation). These are parametric limits and address the concern raised by Sierra Club's comment that no emissions limits are set. Both normal operation limits and parametric limits during the extraordinary one-time commissioning event are consistent with the Draft Permit. Note that the Draft Permit on pages 46-47 states as follows in reference to Group II: Coking Processes and Equipment, Group II-G Coking Process Start-Up:

> Description: Start-up of the facility is a one-time, extraordinary event during which equipment is heated and cured, oven bricks are expanded to full size and downstream control equipment is seasoned and brought on-line. During

start-up, temporary natural gas burners are used at each oven to begin the heating, dry-out and curing of the silica bricks and cast refractory materials in the ovens, crossover tunnel, HRSG header and emergency stacks. Start-up occurs one bank of 60 ovens at a time and can occur only once.

. . .

c. For start-up, the coal charged to each oven shall not exceed 42.5 tons (per 48 hour cycle) until start-up is complete. [401 KAR 51:017]
d. The BACT determination for SO_2 emissions during start-up requires that the coal sulfur content, based on a weekly composite sample, shall not exceed 1.1 percent by weight of coal. [401 KAR 51:017]

The NOD Response contains further detail regarding the startup process:

STEP 1: Initial coke battery, common tunnel, and emergency stack heat-up.

The coke ovens are initially started up by gradually heating them with temporary natural gas burners to the point that the brickwork has absorbed enough surface heat to start a coking cycle. The correct heat-up of the oven brick and downstream refractory is critical for proper dry out, curing, and expansion. A steel exoskeleton with spring type tensioners is built around the brick oven, which must also work in concert with the expansion of the oven. Incorrectly heating the brick and/or refractory will lead to premature failure, up to and including immediate damage. Providing a uniform heating profile evenly distributed across the ovens is critical.

The initial heating is estimated at 25 days due to the sheer mass of silica brick in the ovens, refractory in the common tunnels, and emergency stacks and the slow curing process. To avoid damage to the coke oven batteries, heat-up rates and hold times "soaking" are followed very closely. At temperatures below 1,100 °F the ramp up rate is not to exceed 5 °F/hour; up to roughly 1,800 °F the ramp up rate is not to exceed 7 °F/hour; then above 1,800 °F the ramp up rate is not to exceed 20 °F/hour. The first step of the heating process is completed utilizing natural gas burners to bring the internal oven and oven surface temperatures close to operating temperatures of roughly 2,300 °F (1,260 °C). Ovens are heated up in banks to ensure the uniform growth and curing of the oven bricks and downstream refractories as well as to avoid natural gas supply limits. There are 4 X 30 oven banks, which would be heated as 2 X 30 then 2 X 30 per Figure 1. During startup the [coke oven] flue gas created by natural gas combustion is routed to the emergency stacks, which act as a "chimney" that provides draft. Common tunnels are located at the middle of 2 X 30 linear oven banks to ensure adequate draft is created at the end ovens under normal operating mode. Therefore, it is not possible to use 30 ovens to heat up the rest of the ovens as the [coke oven] flue gas flow cannot be routed to the remaining ovens.

Due to the high natural gas makeup requirement, oven bank startups are staged in a maximum of 60 ovens. As highlighted earlier, uniform heating is key to a successful startup without immediate and/or long-term damage to the coke oven batteries as the system expands.

Natural gas heat-up is performed with a single natural gas burner per oven with an air blower for controlling complete combustion and flame temperatures, which requires excess oxygen. This excess oxygen requirement pulls in air (79% Nitrogen, and 21% O_2), which adds to the amount of [coke oven] flue gas that must be handled. The entire coke oven is heated from a single burner at a single oven door. The natural gas is completely combusted and the combustion products ([coke oven] flue gas) travel through the crown, to the downcomers, to the sole flue, up the uptakes, through the uptake dampers, through the common tunnel, and eventually out the emergency stack. This type of heating, convective heating, is not efficient.

As shown in the pictures, the heat is introduced at one location, the coke side door (door where coke is pushed out of the oven), as opposed to the design heat input from a coal bed in the oven, which is well distributed and consistent with the design of the coke ovens. Therefore, SunCoke's experience in starting up heat recovery coke batteries concluded expediting initial heat-up is detrimental to the life of the coke batteries, and therefore, variance from proven practice is not recommended.

STEP 2: Introduction of coal to complete the system heat-up

The oven brick and downstream refractories in the common tunnel, crossovers, emergency stacks, and ultimately the heat recovery steam generator (HRSG) header are heated to full operating temperatures by charging the ovens with metallurgical coal (starting at approximately 27 to 35 tons/oven), then gradually increasing the charge up to operating tonnage (47 to 50 tons/oven). The volatile matter in the metallurgical coal is the heat source. Since the metallurgical coal bed is evenly distributed, the thermal mass during the coking process allows for uniform heating. Further, the combustion of the volatile matter is a two stage process that occurs in the crown and the sole flues, which uniformly heats the crown, walls, downcomers, floor, and uptakes. The predominant form of heating using coal is more efficient radiant heating as opposed to less efficient convective heating that occurs with natural gas. This uniform balance of heat, consistent with the design of the coke oven batteries, is required for successful and reliable heat-up to avoid damage to brick, refractory, and steel.

Once the ovens are charged with metallurgical coal, the burners are removed from the ovens. This is required as the burners are set up on the coke side of the ovens where the hot car travels to receive the coke and the door machine must travel. Once the bank of ovens is charged with metallurgical coal and natural gas makeup subsides, the next bank of ovens can begin heat-up with natural gas without facing supply limits. The alternative of heating, drying, curing, and expanding all 120 ovens, downstream refractories, and downstream systems with natural gas to full operating temperatures would require over 1,000,000 scf/hour of natural gas, an impractical number that could not be supplied. In addition, the combustion products from the natural gas are considerably higher (>30%) assuming 8% excess oxygen than those produced by the recommended process of charging with metallurgical coal and could overload downstream systems.

The alternative of heating drying, curing, and expanding all 120 ovens, downstream refractories, and downstream systems with a liquid-based fuel (LPG, naphtha, diesel) to full operating temperatures creates a considerable safety exposure as any imbalance in oxygen to fuel could create an explosive situation, not to mention a considerable cost impact. In addition, none of the fuels mentioned is less polluting than natural gas, so the pollutant generation during startup would be increased from current estimates with their use.

Therefore, heating up to system operating temperatures per design with metallurgical coal provides the most uniform heating to allow proper drying, curing, and expansion for the long-term reliability of the coke oven batteries. Along with this, the coal systems, machinery, and coke handling systems can all be tested out while commissioning the coke ovens to ensure an efficient startup.

STEP 3: Heat up of the next 60 ovens and commissioning the HRSGs

Once 60 ovens have been charged with metallurgical coal and ramp up has begun on coal charges, the second 60 oven bank will begin heating up on natural gas similar to the first 60 oven bank. The first 60 oven bank charging coal and the second 60 oven bank heating up on natural gas are routed to the emergency stacks, which are creating draft for the process.

Before [coke oven] flue gas can be routed to the HRSGs the crossover tunnel refractory and HRSG header refractory must be heated up, dried out, and cured. This is typically performed by temporary natural gas burners through ports with the combustion [coke oven] flue gas being routed to the emergency stack.

Heating up the HRSG requires that draft be pulled via the induced draft fan(s). The HRSG has water circulating through the water/steam side. This cools the [coke oven] flue gas to protect the downstream air quality control system during heat-up. During heat-up the [coke oven flue] gas is routed through the HRSG, the circulating dry scrubber (or bypass), bypasses the baghouse to avoid damage, through the induced draft fan(s), and then out of the main stack. Prior to attempting any type of startup on the air quality control system, proven stable operation must be accomplished at the HRSGs. The HRSGs control the temperature to a tight range for the circulating dry scrubber operation (typically 350 to 400 °F).

To protect the downstream equipment requires all three HRSGs to be in stable operation. To accomplish this requires each to be running at >50% of its design capacity. This directly correlates to reaching approximately 80% of the full design load [coke oven] flue gas flow for stable operation of the HRSGs (80% full load / 3 HRSGs = 27% of full load to each HRSG / 50% capacity of full load for each HRSG = 54% of design capacity). Since the coking operation is a batch process, there is a batch like variation in [coke oven] flue gas flow. There must be enough [coke oven] flue gas to maintain >80% design flow to each of the HRSGs even at the trough of [coke oven] flue gas flow during the end of cycle operation of the coking process. This is the trigger for obtaining safe, reliable, and stable operation of the HRSGs. Heat up of the first HRSG is expected to begin around day 40 during ramp up of coal to the first 60 ovens and after heat up on natural gas has begun on the second 60 ovens. The [coke oven] flue gas exhaust point will be moved from the emergency stacks to the main stack (bypassing the air pollution control system) during startup of the HRSGs. The point at which adequate [coke oven] flue gas flow is generated on a consistent basis to start up the HRSGs is expected at roughly 45 to 50 days after start of initial heat up where the first bank of 60 ovens has ramped coal charge up to 42.5 tons/oven and the second bank of 60 ovens is >50% through heat-up on natural gas. Reliable stable operation is expected to take on the order of 7 days for each HRSG. As with normal operation, the third HRSG needs to be available to handle the [coke oven] flue gas flow should one of the HRSGs come offline. A single HRSG can only handle 50% of the load of the system.

Therefore, enough [coke oven] flue gas must be generated to provide consistent, stable operation of the HRSGs in order to begin commissioning the air quality control system without risking damage (which could ultimately inhibit emission removal efficiencies).

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STEP 4: Circulating dry scrubber commissioning and charging coal to the second 60 oven bank

With stable HRSG operation established, the target circulating dry scrubber inlet temperature can be obtained. The circulating dry scrubber will be slowly heated up to operating temperatures with the [coke oven] flue gas from the HRSGs. The induced draft fan(s) will be operating to create draft for the system, which then goes out the main stack. For the circulating dry scrubber to establish the fluidized bed there must be enough steady [coke oven] flue gas. The circulating dry scrubber uses a [coke oven] flue gas recycle, which will be used on startup to establish fluidization. Prior to introducing lime the system must be at the required temperature range to allow for moisture addition and lime activation. Again it is absolutely critical that the HRSGs are stable to avoid temperature swings, which impact the downstream equipment up to and including immediate damage. High moisture levels and/or high temperatures to the baghouse will ruin the bags. As each circulating dry scrubber is designed for 100% capacity, [SESS] will start up one CDS, test out, then start up the second CDS and run on just the second CDS and then ultimately operate both in parallel. This is expected to take on the order of 14 days after reliable HRSG operation.

Therefore, to establish full operation on the HRSGs is roughly 21 days followed by 14 days for full operation of the CDS units. By roughly 70 to 80 days into startup of the three HRSGs and the two CDS units would be online.

Ultimately, the target startup process remains consistent with commissioning of the circulating dry scrubbers well within 40 days after the last oven has been charged with coal as proposed in the permit application.

III. <u>The Draft Permit Contains All Applicable Emission Limitations And Standards, As Required By Kentucky Regulations.</u>

Comment No. 6: Sierra Club states that the Draft Permit's requirement to submit to KDAQ a fugitive dust-plan required under 40 C.F.R. § 60.254(c) before commencing startup, and to include proposed BACT controls in that fugitive coal dust control plan in order to comply with 401 KAR 51:017, constitutes a failure of the Draft Permit to contain all applicable regulations at the time of permit issuance. *See* Comments at 9-10.

Response No. 6: Sierra Club confuses SESS's obligations to meet a new source performance standard ("NSPS") with its PSD requirements. A fugitive coal dust control plan under 40 C.F.R. § 60.254(c) is an NSPS and not, in and of itself, a PSD requirement. Although the Draft Permit makes compliance with 401 KAR 51:017 (PSD regulations) contingent upon compliance with 40 C.F.R. § 60.254(c), submission of the plan at a later date is all that is required by 40 C.F.R. § 60.254(c).

Moreover, contrary to Sierra Club's assertion, the Draft Permit contains the relevant PSD requirements, stating on page 5 that

> Pursuant to 401 KAR 51:017, for Group I equipment, for fugitive PM, the following BACT control technologies shall be applied:
>
> (1) Coal Unloading: Barge unloading, no controls
> (2) Coal Piles: Radial stacker, wet material, wind screen and/or berm
> (3) Coal Crushing: Enclosure, wet material
> (4) Coal Handling:
> (i) Blended Crushed Coal Storage: Enclosed bins, wet material
> (ii) Coal Conveyors: Enclosure (except where prohibited due to moving equipment), wet material

Thus, the Draft Permit states exactly what is considered BACT for coal piles, and obligates the Plant to utilize those technologies. The fact that the fugitive coal dust control plan, which must include these technologies, is actually submitted at a later date does not mean that BACT has not been identified at the time of permit issuance. All applicable requirements are therefore present in the Permit at the time of permit issuance.

Comment No. 7: Sierra Club states that the failure of the Draft Permit to include 401 KAR § 59:015, which applies to any indirect heat exchanger, constitutes a failure to contain all applicable requirements due to the presence of the HRSGs. *See* Comments at 10.

Response No. 7: Sierra Club is incorrect that 401 KAR § 59:015 applies to HRSGs, apparently because Sierra Club does not understand how HRSGs operate. As noted by Sierra Club, an indirect heat exchanger is defined as "a piece of equipment, apparatus, or contrivance *used for the combustion of fuel* in which the energy produced is transferred to its point of usage through a medium that does not come in contact with or add to the products of combustion." 401 KAR 59:015 § 1(5) (emphasis added). However, HRSGs are not "used for the combustion of fuel." In fact, nothing is combusted in a HRSG. The HRSG receives hot coke oven flue gas and cools it in order to route it to the flue gas desulfurization system. Using the heat to produce steam and routing the steam to an electricity generating turbine is merely a derivative product of this process. Thus, 401 KAR § 59:015 does not apply.

Comment No. 8: Sierra Club claims that 40 C.F.R. Part 60 Subparts Db or Dc, which implement performance standards for steam generating units, should apply because the EPA policy that Subpart Db does not apply to coke oven HRSGs is predicated upon the agency determination that no supplemental fuels are combusted. According to Sierra Club, this prerequisite is absent because SESS will use natural gas as a supplemental fuel for steam generation. *See* Comments at 10.

Response No. 8: Sierra Club mischaracterizes the EPA Subpart Db applicability determination it cites. Subpart Db applies to steam generating units, which the regulations define as "a device that *combusts* any fuel or byproduct/waste and produces steam or heats water or heats any heat transfer medium." 40 C.F.R. § 60.41b (emphasis added). The regulations also state: "This term [steam generating unit] does not include process heaters as they are defined in this subpart." *Id.* In the 1999 EPA applicability determination, EPA stated in no uncertain terms that

> neither the coke ovens nor the waste heat boilers meet the above definition of a steam generating unit. The coke ovens more closely match the definition of process heaters, and are therefore excluded from the steam generator definition, because their primary purpose is to initiate the chemical conversion of coal to coke using the heat from the combustion of the coke oven [flue] gas. The waste heat boilers do not have burners or air introduction, and as a result, there is no combustion occurring in them. Also, these boilers have zero heat input, because their heat is from the excluded category of '. . . exhaust gases from other sources . . . .'

See EPA Applicability Determination Control No. 9900003, "Steam Generating Unit Defined" (Jan. 14, 1999). Like the nonrecovery coke plant that was the subject of the applicability determination, SESS's coke ovens are categorically excluded from the steam generator definition because their primary purpose is to initiate the chemical conversion of coal to coke. Therefore, the SESS Plant's coke ovens are more like process heaters than steam generators.

In addition, like the waste heat boilers in the applicability determination, combustion will not occur in the SESS Plant's HRSGs, and the HRSGs have zero heat input. The HRSGs obtain heat from the excluded category of "exhaust gases from other sources." 40 C.F.R. § 60.41b ("Heat input . . . does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources, such as gas turbines, internal combustion engines, kilns, etc."). This is true even when natural gas is sparged in the ovens. The HRSG obtains heat from the ovens; it does not have any "heat input," which is defined as "heat derived from combustion of fuel *in a steam generating unit*." *See id.* (emphasis added). The combustion must occur in the steam generating unit itself in order for the heat to be considered heat input. At the Plant, the volatile matter evolved from the coal is oxidized in the coke ovens, not in the steam generators. Because there is no heat input to the HRSGs or combustion taking place in the HRSGs, Subpart Db does not apply.

Comment No. 9: Sierra Club claims that the Draft Permit improperly excludes the Acid Rain Program by relying on an exemption for cogeneration units provided the units supply "equal to or less than one third [their] potential electrical output capacity or equal to or less than 219,000 MWE-hrs actual electric output on an annual basis to any utility power distribution system for sale." 40 C.F.R. § 72.6(b)(4). According to Sierra Club, the Acid Rain Program applicability determination must be based on the combined electricity generation from all three generators when calculating whether the 219,000 MWE threshold is exceeded. *See* Comments at 10-11.

Response No. 9: The Draft Permit correctly exempts the SESS Plant from the Acid Rain Program. As stated in the Permit Application, federal regulations exempt from the Acid Rain Program certain types of units, including "cogeneration facilities" that commence construction after November 15, 1990 and supply "equal to or less than one-third its potential electrical output capacity or equal to or less than 219,000 MWe-hrs actual electric output on an annual basis to any utility power distribution system for sale (on a gross basis)." 40 C.F.R. § 72.6(b)(4)(ii); *see also* Permit Application, at 4-7.

The regulations further define a "cogeneration unit" as "a unit that has equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam) for industrial, commercial, heating, or cooling purposes, through sequential use of energy." *Id.* § 72.2. The heat recovery coke plant is analogous to a "cogeneration facility." *See* Draft Permit, at 66. Heat from the oxidation of the coal volatiles is sequentially used to evaporate moisture, carbonize the coal to coke, heat the refractory materials, and make steam as a derivative product from the HRSGs. Indeed, neither heat recovery coke plants nor related HRSGs have ever been subject to the Acid Rain Program.

There are several possible definitions of a "unit" which would provide exemptions to the Acid Rain Program. SESS could define a unit as a single coke oven (which would create 120 units) or a contiguous battery of ovens (which would be 30 contiguous ovens and thus would create four units). The simplest and most restrictive is to consider each HRSG (the actual steam generating device) as a "unit", thus resulting in three units. Each HRSG would be considered a unit because it provides the steam that is ultimately converted to electricity and sold. None of these three units will produce "219,000 MWe-hrs actual electric output on an annual basis to any utility power distribution system for sale (on a gross basis)." 40 C.F.R. § 72.6(b)(4)(ii).

SESS's position is bolstered by an EPA December 19, 2008 Determination. *See* Letter from Clean Air Markets Division, EPA, to Oxbow Calcining LLC (Dec. 19, 2008). A petroleum coke calcining plant had considered attaching new waste heat boilers to three existing kilns in order to produce steam; that steam would flow to a new common steam header connected to a new steam turbine generator to produce electricity for sale. EPA determined that each kiln constitutes a "cogeneration unit" because each kiln was considered a combustion device and because upon implementation of the proposed project, the heat produced in each kiln would be used first to calcine the green pet coke in the kiln and then to produce electricity at the steam turbine. *Id.* at 1–2.

With respect to the SESS Plant, the amount of electricity that could be attributed to each independent HRSG will be less than 219,000 MWe-hrs/year. The total power production for the Plant (all three HRSGs) will be 40–75 MW. The three HRSGs in parallel will typically operate simultaneously (although each HRSG will be sized to take 50% of the waste heat if one is offline for maintenance). With all HRSGs operating (the typical case), the total power production attributed to each HRSG will be 13–25 MW. The annual electricity sold attributable to each HRSG (even operating 24 hours/day, 365 days/year) will be less than 219,000 MWe-hrs. *See* Permit Application, at 4-8. Therefore, the Draft Permit correctly exempts the SESS Plant from the Acid Rain Program.

Moreover, the Draft Permit requires that SESS keep records of electrical output sold to demonstrate that each HRSG supplies 219,000 MWe-hours or less per year and continues to fall under the exemption for cogeneration units. *See* Draft Permit, at 66.

Comment No. 10: Sierra Club states that the Plant does not include adequate mercury controls because the only controls for mercury are those already required for PM. Therefore, according to the Sierra Club, the Draft Permit violates 401 KAR 63:020 due to its failure to include a health-based risk analysis for mercury. *See* Comments at 11.

Response No. 10: The issues raised in this comment do not relate to any PSD requirement. The basis for regulating mercury emissions through the regulation of PM is explained in further detail in Response No. 11.

Kentucky requires control of emissions of toxic substances that are not subject to other regulations. *See* 401 KAR 63:020, Section 1 ("The provisions of this administrative regulation are applicable to each affected facility which emits or may emit potentially hazardous matter or toxic substances . . . , *provided such emissions are not elsewhere subject to the provisions of the administrative regulations of the Division for Air Quality.*") (emphasis added). SESS will be subject to two MACT standards (adopted in 401 KAR 63:002): 40 C.F.R. Part 63, Subpart L (National Emission Standards for Coke Oven Batteries) and 40 C.F.R. Part 63, Subpart CCCCC (National Emission Standards for Coke Ovens: Pushing, Quenching, and Battery Stacks). As stated in our Response to Comment No. 11, the purpose of these MACT standards is to control hazardous air pollutants ("HAPs") through work practices and limitations on emissions of PM and opacity as surrogates for emissions of toxic compounds. Thus, Sierra Club is incorrect; SESS is subject to mercury limitations through the MACT standards' control of mercury via PM limitations.

Although SESS's operations are subject to other regulations and therefore not subject to 401 KAR 63:020's requirements, SESS performed a toxics assessment for mercury and other compounds. *See* Permit Application, at 6-41–42; Table 6-13 (SESS Modeled Toxic Air Pollutants and Results), at 6-43–44. A very conservative mercury emission rate of 400 lbs/year was used for this analysis assuming maximum coke production, the maximum level of mercury in the coal for an entire year, and *no removal* of mercury by *any* of the air pollution control equipment. This assumption is highly conservative because some mercury will be removed by the flue gas desulfurizer and the baghouse. The ambient concentrations were estimated for each year of modeled meteorological data for those emission units that will operate on a daily basis. The modeled ambient concentrations of mercury were compared to values in the Regional Screening Level Resident Air Supporting Table (May 2012 version) on EPA Region III's website (www.epa.gov/reg3hscd/risk/human/rb-concentration_table/Generic_Tables/index.htm). *Id.*

The risk based concentration of mercury is 0.31 µg/m3 (for a Hazard Index of 1.0). The risk based concentration represents an estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious effects during a lifetime. The maximum modeled annual average concentration of mercury was 0.00064 µg/m3 or approximately 480 times lower than the risk based concentration. This analysis successfully demonstrated that the health of residents living near SESS is protected at a very conservative level of mercury emissions from the Plant.

The November 2013 version of the Regional Screening Level Resident Air Supporting Table now lists risk based concentrations for Hazard Indices of both 1.0 and 0.1. The more conservative Hazard Index of 0.1 risk based concentration for mercury is 0.031 µg/m3. Even considering this very conservative value, the maximum modeled mercury concentration of 0.00064 µg/m3 is approximately 48 times lower than the risk based concentration, which confirms that the health of residents living near SESS is adequately protected.

Moreover, Sierra Club assumes there will be no removal of mercury; this is incorrect. As explained in the Permit Application, during the coking process, the mercury in the coal is volatilized and converted to mercury vapor. This vapor may subsequently form mercury compounds or may be adsorbed onto the surface of particles. The mechanisms are complex, but mercury is ultimately present in three basic forms: particulate-bound mercury, oxidized mercury, and elemental mercury. The speciation of mercury into these three forms is important because it impacts the capture of mercury by existing air pollution control devices. Particulate mercury is captured by particulate control devices such as baghouses. Oxidized mercury is more easily captured in wet flue gas desulfurization systems as well as dry scrubbers. Elemental mercury is the hardest of the three forms to capture by traditional air pollution control devices, but dry scrubbers are known to remove some amount of elemental mercury. *See* Permit Application, at 5-82 (citing Senior 2001).

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Comment No. 11: Sierra Club claims that MACT standards must be applied to the SESS Plant for all HAPs, including mercury. *See* Comments at 11.

Response No. 11: The Draft Permit requires compliance with 40 C.F.R. Part 63, Subpart L (NESHAP for Coke Oven Batteries) and Subpart CCCCC (NESHAP for Coke Ovens: Pushing, Quenching, and Battery Stacks). These are the only MACT standards that are applicable to the SESS Plant, and they regulate PM and opacity as a surrogate for mercury and other metals.

When promulgating Subpart CCCCC, EPA stated the rule "will also significantly reduce emissions of other HAP, such as *metals* . . . However, we do not have a reliable means of estimating the overall reductions of these other HAP emissions." *See* 68 Fed. Reg. 18008, 18022 (Apr. 14, 2003) (emphasis added). In response to a comment that "EPA had not explained why PM is a suitable surrogate for HAP emissions from quenching," EPA explained

> [w]e agree with the comment that baffles reduce PM emissions. In addition, we believe that baffles also reduce the emission of HAP metal compounds contained in the particles of grit released, as well as semivolatile and VOC such as polycyclic aromatic hydrocarbons (PAH) and benzene, when green coke is quenched. Semivolatile organic compounds evolve from green coke and condense to form fine PM or condense on other particles during the quenching process. Consequently, baffles reduce emissions of both metal and organic HAP.

Id. at 18017-18. Additionally, in response to a comment that "EPA has not met its burden of demonstrating that opacity is a reasonable surrogate for HAP emissions," the agency responded that "[i]t is well established that opacity is directly correlated with the concentration of particles in emissions. Our tests have shown that the particles emitted during coke oven pushing contain HAP compounds, including [polycyclic organic matter] and *metals* . . . ." *Id.* at 18020 (emphasis added). Therefore, the MACT standards applicable to the SESS Plant do not regulate mercury, but provide standards for PM and opacity as surrogates for mercury and other metals and hazardous substances.

Comment No. 12: Sierra Club claims that the SESS Plant may meet the definition of a facility covered by the utility MATS rule, which applies to coal-fired electric generating units (i.e., units burning coal more than 10% of the average annual heat input during any 3 consecutive calendar years) of more than 25 megawatts electric that serves a generator that produces electricity for sale. 40 C.F.R. § 63.10042. Therefore, according to Sierra Club, compliance with the utility MATS rule must be assured in the Draft Permit. *See* Comments at 11-12.

Response No. 12: As noted by Sierra Club, the definition of an electric utility steam generating unit ("EGU") includes a "*fossil fuel-fired unit* that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system." 40 C.F.R. § 63.10042 (emphasis added). The HRSGs at the SESS Plant will not meet this definition of an EGU because the HRSGs are not "fossil fuel fired unit[s]." "Fossil fuel-fired" is defined as "an electric utility steam generating unit (EGU) that is capable of *combusting* more than 25 MW of fossil fuels." *Id.* (emphasis added). The Plant's HRSGs will not combust coal or any other fuel.

IV. The Draft Permit Contains Sufficient Testing, Monitoring, Reporting, And Recordkeeping Requirements To Ensure Compliance With The Permit's Terms And Conditions.

Comment No. 13: Sierra Club argues that the Draft Permit's BACT requirements for SO_2 improperly rely on a long-term compliance demonstration to protect short-term limits, such as measuring sulfur content based on a monthly composite sample. Sierra Club also argues that the permit limitation to not charge more than 20 ovens per hour is unenforceable because of no monitoring or recordkeeping requirements. *See* Comments at 12.

Response No. 13: All operations at SESS have short-term limits. The largest source of SO_2 is from coking where emissions will be controlled by a CDS/baghouse system. *See* Draft Permit, at 19. Coking emissions will be exhausted through the main stack where SO_2 emissions are monitored by a CEM system. *See id.* at 25; Table I, at 135. The SO_2 emissions will be monitored hourly with the SO_2 limit specified as a 3-hour average. Short term emissions from charging are limited by the sulfur content of the coal and the maximum number of ovens that can be charged per hour. The number of ovens that can be charged per hour will be limited based on physical design capacity. Under the Draft Permit, if any 3-hour average SO_2 value exceeds the standard, SESS "shall, as appropriate, initiate an inspection of the control equipment and/or the CEM systems and make any necessary repairs as soon as practicable." *Id.* Therefore, contrary to Sierra Club's assertions, the Draft Permit contains sufficient monitoring and recordkeeping requirements.

Comment No. 14: Sierra Club states that emission limits for the SESS Plant's quench towers are improperly based on emissions of particulate matter per ton of wet coal even though there is no wet coal involved in the quenching process. According to Sierra Club, the Draft Permit also improperly requires only an initial compliance test with no periodic testing. *See* Comments at 13.

Response No. 14: The PM emission factors from quenching on a pound per ton of wet coal basis are consistent with emission factors used for other similar facilities, EPA's RACT/BACT/LAER Clearinghouse, and EPA's "Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, Document Number AP-42."

In addition to requiring an initial compliance test, the Draft Permit also requires weekly monitoring of quench water to demonstrate continuous compliance with the total dissolved solids ("TDS") limit, as required by 40 C.F.R. Part 63, Subpart CCCCC. *See* Draft Permit, at 120. Therefore, contrary to Sierra Club's assertions, the Draft Permit contains sufficient emissions and monitoring requirements pertaining to the SESS Plant's quench towers.

Comment No. 15: Sierra Club states that the emission limits for the SESS Plant's cooling towers are flawed because the Draft Permit does not monitor or set a BACT limiting TDS content in the circulating water, and does not require periodic testing to ensure that design drift rate is not degrading with time. According to Sierra Club, "emission rates from cooling towers depend upon the draft [sic] rate, circulation water rate, and TDS content of the water." *See* Comments at 13.

Response No. 15: The Draft Permit sets forth a cooling tower water circulation rate and drift requirement. *See* Draft Permit, at 59. This limit is based on the physical design capacity. The Draft Permit also requires monthly monitoring and recording of visible emissions of the cooling tower, which addresses any concern about a degrading drift rate, and has a provision for TDS testing if requested by KDAQ. *See id.* at 60. Therefore, contrary to Sierra Club's assertions, the Draft Permit contains sufficient testing and monitoring requirements.

Comment No. 16: Sierra Club claims that the Draft Permit fails to include adequate enforcement provisions for the rated capacity of the coal charging operation, particularly for the hourly capacity of 500 ton/hr per machine. *See* Comments at 13.

Response No. 16: The number of ovens that can be charged per hour will be limited based on physical design capacity. The charge limit is 500 ton/hour per pushing/charging machine, which would equate to 10 ovens with 50 tons per charge per oven, which is the maximum charge rate that cannot be exceeded based on physical design capacity. *See* Draft Permit 12, 19.

Comment No. 17: Sierra Club states broadly that the Draft Permit does not contain compliance certification, testing, monitoring, reporting, and recordkeeping requirements sufficient to ensure compliance with the terms and conditions of the Draft Permit. *See* Comments at 13.

Response No. 17: The Draft Permit establishes operating limitations, compliance demonstration methods, testing requirements, specific monitoring requirements, specific recordkeeping requirements, specific reporting requirements, and (where appropriate) specific control equipment operating conditions for each of the 29 Emission Units at the SESS Plant.

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V. There Are No Ambiguous Or Undefined Terms That Render The Draft Permit's Provisions Unenforceable.

Comment No. 18: Sierra Club states that many of the Draft Permit's terms are unenforceable because they are either not defined or are ambiguous, including: "wet tons of coal"/"wet coal," "normal operation," and "pounds per dry ton coal." *See* Comments at 13-14.

Response No. 18: Although the Draft Permit does not specifically define "wet tons of coal"/"wet coal," "normal operation," or "pounds per dry ton coal," these terms are common and commercially acceptable terms, as further demonstrated by their use in regulations. The term "wet coal" simply means the total weight of the coal: dry coal with moisture included. This term is consistent with those found in limits and work practice standards for other similar facilities, RBLC data, AP-42, and MACT standards.

Regarding the alleged ambiguity of the term "normal operation," SESS's heat recovery coke batteries are unique in the fact that once they have completed their initial commissioning, which requires heat up, dry out, and curing of the various refractories, they are not capable of shutting down. In light of this fact, the term "normal operation" is defined as any time period following the initial commissioning start-up which is defined as an exceptional one-time event. See our Response to Comment No. 5 for further detail. Indeed, federal rules commonly use the term "normal operation." *See, e.g.,* 40 C.F.R. §§ 63.305(c)(2)(i), (3), 63.309(c)(3)(ii), 63.7325.

The term "pounds per dry ton coal" appears in federal rules that apply to the SESS Plant. For example, the PM limit for charging is expressed in pounds per dry ton coal in 40 C.F.R. Part 63, Subpart L. *See, e.g.,* 40 C.F.R. § 63.303(d)(2). Dry coal is the total weight of the coal minus its moisture content.

VI. The Draft Permit Meets Public Participation Requirements.

Comment No. 19: Sierra Club claims that "the Draft Permit does not contain the address of the proposed facility, as is required by regulation. 401 KAR 52:100 § 5(2) clearly states that among the mandatory information required in a public notice is the 'Name and address of the permit applicant and, if different, the name and address of the facility.'" Sierra Club claims that this regulation has been violated because the Draft Permit only lists the location of "US 23, Greenup County, KY," which is allegedly up to 25 miles away from the city of South Shore, KY. *See* Comments at 14.

Response No. 19: Sierra Club's claim that the Public Notice does not list the Plant's address is incorrect. Sierra Club cites to the Draft Permit for the Plant's location instead of the Public Notice, seemingly in an attempt to apply a requirement relevant only for the Public Notice to the Draft Permit itself. As the attached Public Notice states, SESS applied to "construct and operate a metallurgical coke manufacturing facility *to be located US 23, South Shore, Kentucky*." *See* Ex. A (emphasis added). 401 KAR 52:100 § 5, "Information

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Included in Public Notice," states that the "[n]ame and address of the permit applicant and, if different, the name and address of the facility" be included in the public notice. The location of the SESS Plant on Route 23 in South Shore, Kentucky is explicit—it appears in the first sentence of the first paragraph of the Public Notice--and cannot be read to mean the Plant is in other locations like Flatwoods, Kentucky, as Sierra Club suggests. Moreover, the Permit Application, which was readily available to Sierra Club upon request from KDAQ, provided a detailed aerial map of the location of SESS in Greenup County. *See* Ex. B (Permit Application, Figure 6.8, at 6-28).

Comment No. 20: Sierra Club states that the failure to list the degree of increment consumption in the Draft Permit also violates public notice requirements. Reporting the cumulative increment consumption from all new sources in the region, but not providing the degree of increment consumption expected to occur from this project, is not adequate. *See* Comments at 15.

Response No. 20: Class II increment consumption for each pollutant is clearly listed in Table 8 in the SOB and Public Notice. It is appropriate to include all sources constructed after the applicable baseline date in the increment analysis. If the cumulative increment consumption analysis is acceptable, then the degree of increment consumption from this project alone obviously is acceptable. The maximum SESS impacts are shown in Table 7 of the SOB.

The Federal Land Manager does not anticipate adverse impacts in any Class I areas, consistent with the Public Notice provided by KDAQ: "The project is located approximately 280 km west of the nearest Class I area – Otter Creek Wilderness, WV. Based on the Q/D≤10 analysis, no adverse impact to Air Quality Related Values in the Class I area is anticipated." *See*. Ex. A. Additionally, SESS provided a comparative Class I increment analysis in Table 7-4 of the supplemental information it provided on November 12, 2013. This analysis demonstrated that no Class I increments were exceeded.

Sincerely yours,

David J. Schwake

cc: Ms. Laurie Williams, Esq., Sierra Club (via email)
Mr. Sean Alteri, Director, KDAQ (via email)
Mr. Rick Shewekah, Manager, Permit Review Branch, KDAQ (via email)
Ms. Linda Martin, Supervisor, Metallurgy Section, KDAQ (via email)

Enclosures

EXHIBIT A

AIR QUALITY PERMIT NOTICE
Permit # V-13-007
Subject to Prevention of Significant Deterioration (PSD) and Concerning the Construction and Operation of an Coke Manufacturing Facility in Greenup County, Kentucky
SunCoke Engery South Shore, Inc. - Plant I.D. 021-089-00047 - Agency Interest 105793

The SunCoke Energy South Shore LLC of 1011 Warrenville Road, Suite 600, Lisle, IL has applied to the Kentucky Division for Air Quality for a Title V permit to construct and operate a metallurgical coke manufacturing facility to be located US 23, South Shore, Kentucky. The coke production plant, which includes coal handling, a coke oven battery, quenching tower and coke handling facilities, will also include a heat recovery electrical plant in Greenup County, Kentucky. The plant is classified as a Title V major source due to its emissions of regulated air pollutants and hazardous air pollutants. Air quality regulations for prevention of significant deterioration of air quality which define increments of allowable air quality degradation will apply. Increment consumption has been predicted by EPA approved dispersion models to be as follows:

Pollutant	Averaging Period	Cumulative Modeled Concentration (ug/m3)	Project Contribution to Cumulative Impact if greater than PSD Increment (ug/m3)	Class II PSD Increment (ug/m3)	Does SunCoke Impact Cause or Contribute Significantly to a Modeled Violation?
NO2	1-hour	-	-	-	-
	Annual	9.1	-	25	No
SO2	1-hour	-	-	-	-
	3-hour	278	-	512	No
	24-hour	58.5	-	91	No
	Annual	2.7	-	20	No
PM10	24-hour	15.0	-	30	No
	Annual	22.8	<1 (SIL)	17	No
PM2.5	24-hour	7.1	-	9	No
	Annual	1.5	-	4	No

PSD regulations require an increment analysis if pollutant emissions exceed their respective Significant Impact Level (SIL). Based on this requirement, for this permitting action only a Class II increment analysis for the emissions of NOX (annual), SO2 (3-hour, 24-hour and annual), PM10 (24-hour and annual), and PM2.5 (24-hour and annual) is required.

The project is located approximately 280 km west of the nearest Class I area–Otter Creek Wilderness, WV. Based on the Q/D≤10 analysis, no adverse impact to Air Quality Related Values in the Class I area is anticipated.

An electronic copy of the Division's draft permit should shortly become available at http://air.ky.gov/Pages/PublicNoticesandHearings.aspx. Paper copies of the draft permit and relevant supporting information are available for inspection by the public during normal business hours at the following locations:

Division for Air Quality, 200 Fair Oaks Lane, 1st Floor, Frankfort, KY 40601, phone (502) 564-3999; Division for Air Quality Ashland Regional Office, 1550 Wolohan Drive, Suite 1, Ashland, KY 41102, phone (606) 929-5285; and the Greenup County Public Library, 508 Main Street, Greenup, KY 41144, phone (606) 473-6514.

For a period of 30 days the Division will accept comments on the draft permit and afford the opportunity for a public hearing. The first day of the 30 day period is the day after the publication of this notice. Comments and/or public hearing requests should be sent to Mr. James Morse at the above Frankfort address or e-mail James.Morse@ky.gov. Any person who requests a public hearing must state the issues to be raised at the hearing. If the Division finds that a hearing will contribute to the decision-making process by clarifying significant issues affecting the draft permit, a hearing will be announced. All relevant comments will be considered in issuing the proposed permit. U.S. EPA has up to 45 days following issuance of the proposed permit to submit comments. The status regarding EPA's 45-day review of this project and the deadline for submitting a citizen petition will be posted at the following website address: http://www.epa.gov/region4/air/permits/kentucky.htm shortly after the end of this 30-day comment period. Further information can be obtained by calling Ms. Linda Martin at (502) 564-3999.

The Commonwealth of Kentucky does not discriminate on the basis of race, color, national origin, sex, religion, age or disability in employment or the provision of services and provides, upon request, reasonable accommodation including auxiliary aides and services necessary to afford individuals an equal opportunity to participate in all programs and activities. Materials will be provided in alternate format upon request.

EXHIBIT B

SunCoke Energy South Shore Application for Major Source Permit to Construct

December 2012

Prepared for:

SunCoke Energy, Inc.
1011 Warrenville Road, Suite 600
Lisle, Illinois 60532

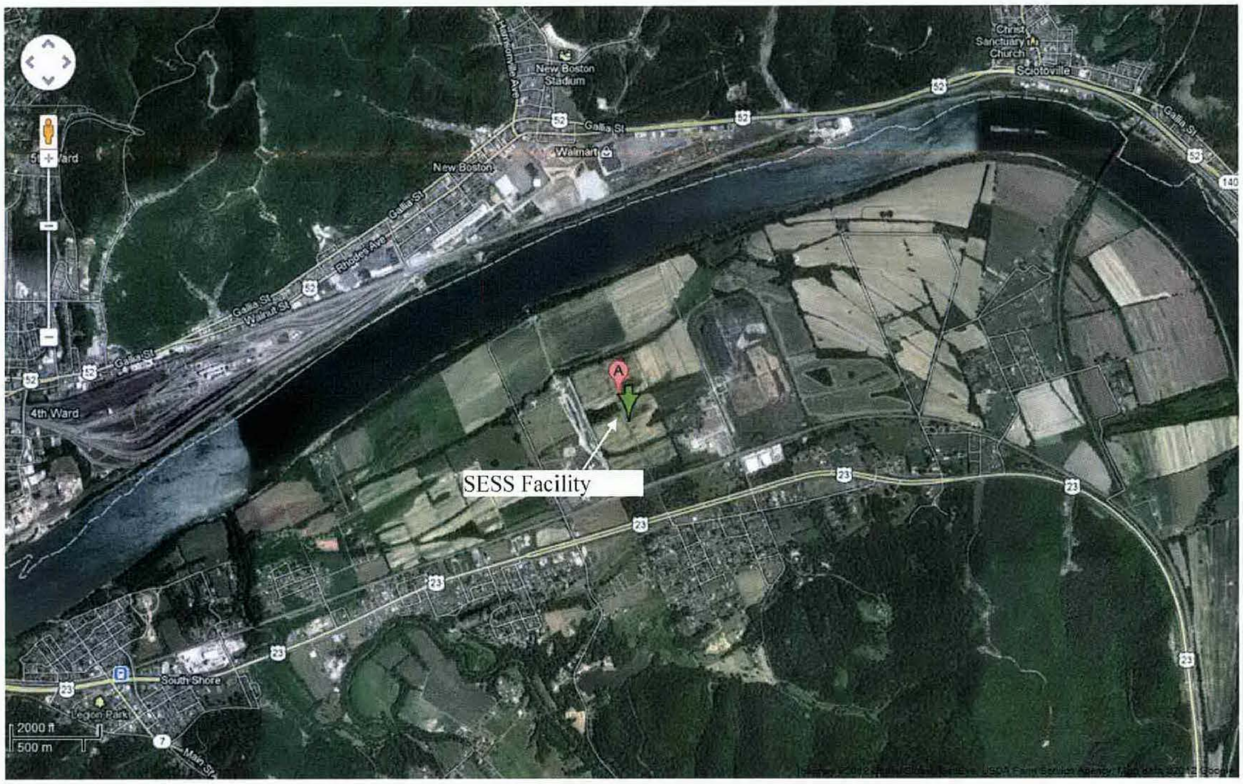

Figure 6-8. Aerial Map of SESS in Greenup County

Commonwealth of Kentucky
Division for Air Quality

COMMENTS AND RESPONSE

ON THE STATEMENT OF BASIS

ATTACHMENT 7

DAQ Bibliography for Analysis of SunCoke Energy South Shore
Draft Construction and Operating Permit V-13-007,
Plant ID 021-089-00047, Agency Interest No. 105793

Note: During the application review processed, DAQ accessed many references. The following is a partial list.

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State of Georgia - Department of Natural Resources, Environmental Protection Division - Air Protection Branch, Stationary Source Permitting Program, Live Oaks Power Plant

State of Ohio Environmental Protection Agency, FDS Co-Generation Facility

State of Ohio Environmental Protection Agency, Haverhill North Coke Facility

State of Ohio Environmental Protection Agency, Middletown Coke Company

Virginia Department of Environmental Quality, Jewell Coke Company

EXHIBIT O

MEMORANDUM OF OPTION FOR SILOAM & REID PROPERTY

[WILL BE PROVIDED AS SOON AS AVAILABLE]

DB 264 Pg 105

HD 11-37
(Rev. 1-67)

Page 1

Sheet 1 of 3

DEED OF CONVEYANCE

Written by MAM

Checked by WSS

December 1970

PARCEL NO. 186

THIS DEED, between John McMahan and Norma McMahan, his wife

parties of the first part, and the Commonwealth of Kentucky for the use and benefit of the Department of Highways, party of the second part.

WITNESSETH: That the said parties of the first part, in consideration of $ 7,500.00 cash in hand paid, the receipt of which is hereby acknowledged, has bargained and sold and does hereby sell, grant and convey to the party of the second part, its successors and assigns forever, the following described property, viz:

A parcel of land lying and being in Greenup County, Kentucky and being a portion of the same tract of land conveyed to the parties of the first part by Goebel Crumeans by deed bearing date of 31st. 13th day of 1-'46 4-'62 which is duly recorded in Deed Book No. 104 182 at page 443 377 in the office of the County Court Clerk of Greenup County, Kentucky, said parcel being described as follows:

PARCEL NO. 186

A certain tract or parcel of land lying on both sides of the centerline of the proposed Ashland - Greenup - South Portsmouth Road and being more particularly described as follows:

(A) Beginning at a point on the Westerly property line 140 feet right (South) of and opposite Station 336+85; Thence running North 25°15' West along the Westerly property line and crossing the proposed roadway centerline at Station 336+64 a distance of 263 feet to a point 120 feet left (North) of and opposite Station 336+46; Thence running North 73°15' East along the proposed Northerly Right-of-Way line a distance of 450 feet to a point 120 feet left (North) of and opposite Station 340+96; Thence running South 14°15' East along the Easterly property line and crossing the proposed roadway centerline at Station 340+91 a distance of 260 feet to a point 140 feet right (South) of and opposite Station 340+85; Thence running South 73°15' West along the proposed Southerly Right-of-Way a distance of 400 feet to the point of beginning, containing 2.54 acres, more or less, of which all 2.54 acres is new Right-of-Way to be acquired.

260

It is understood between the parties hereto and made a covenant herein that the property described above and designated as Parcel (A) is conveyed in fee simple.

(B) Also, beginning at a point in the proposed Southerly Right-of-Way line 140 feet right (South) of and opposite Station 339+00; Thence Southerly 20 feet to a point 160 feet right (South) of and opposite Station 339+00; Thence Easterly 30 feet to a point 160 feet right (South) of and opposite Station 339+30; Thence Northerly 20 feet to a point in the proposed Southerly Right-of-Way line 140 feet right (South) of and opposite Station 339+30; Thence Westerly 30 feet along said Right-of-Way line to the point of beginning, containing 0.01 acres, more or less.

STATE TAX PAID 7.50
1-17-73
[illegible] MOORE, CLERK
[illegible] COUNTY COURT
BY Mary Stultz D.C.

105

It is the specific intention of the grantor herein to convey a temporary easement to the property described above and designated as Parcel (B) for the purpose of removing a building and said easement reverts and terminates upon completion of same.

The acquisition of the Right-of-Way of this project was authorized by the Kentucky Department of Highways Official Order No. 79441. Pursuant to said Order and Regulation HIWA-ACC-CONTR, access to such a project shall be partially controlled.

Sheet 3 of 3

Page 2

The proposed public road extends from Ashland to South Portsmouth (SP ________), (Fed. No. ________) the plans for which are on file in the office of the Department of Highways in Frankfort, Kentucky.

TO HAVE AND TO HOLD said property unto the party of the second part, its successors and assigns, with all the rights and privileges thereunto belonging with covenants of General Warranty.

IN TESTIMONY WHEREOF the parties of the first part executed this deed on this, the 27 day of [illegible] 19[illegible].

WITNESSES:

John McMahan

Norma McMahan

CERTIFICATE OF ACKNOWLEDGMENT

COMMONWEALTH OF KENTUCKY)
) ss.
COUNTY OF Greenup)

I, the undersigned, certify that the foregoing deed was produced before me in my said County and State and duly acknowledged by John McMahan and Norma McMahan, his wife

parties of the first part therein to be their act and deed.

Witness my hand this 27 day of November, 1972.

[illegible] County Court

By [illegible] D. C.

Notary Public State at Large

My Notary Commission Expires 3-31-74

Notary Public County, Ky.

DESCRIPTION BY [illegible]

CLERK'S RECORDING CERTIFICATE

COMMONWEALTH OF KENTUCKY)
) ss.
COUNTY OF Greenup)

I, the undersigned clerk of the county court in and for the County and State aforesaid, certify that the foregoing deed from John McMahan and wife et al to the Commonwealth of Kentucky for the use and benefit of the Department of Highways was lodged for record in my office on the 16 day of Jan, 1973, and has been duly recorded in Deed Book 264, page ________.

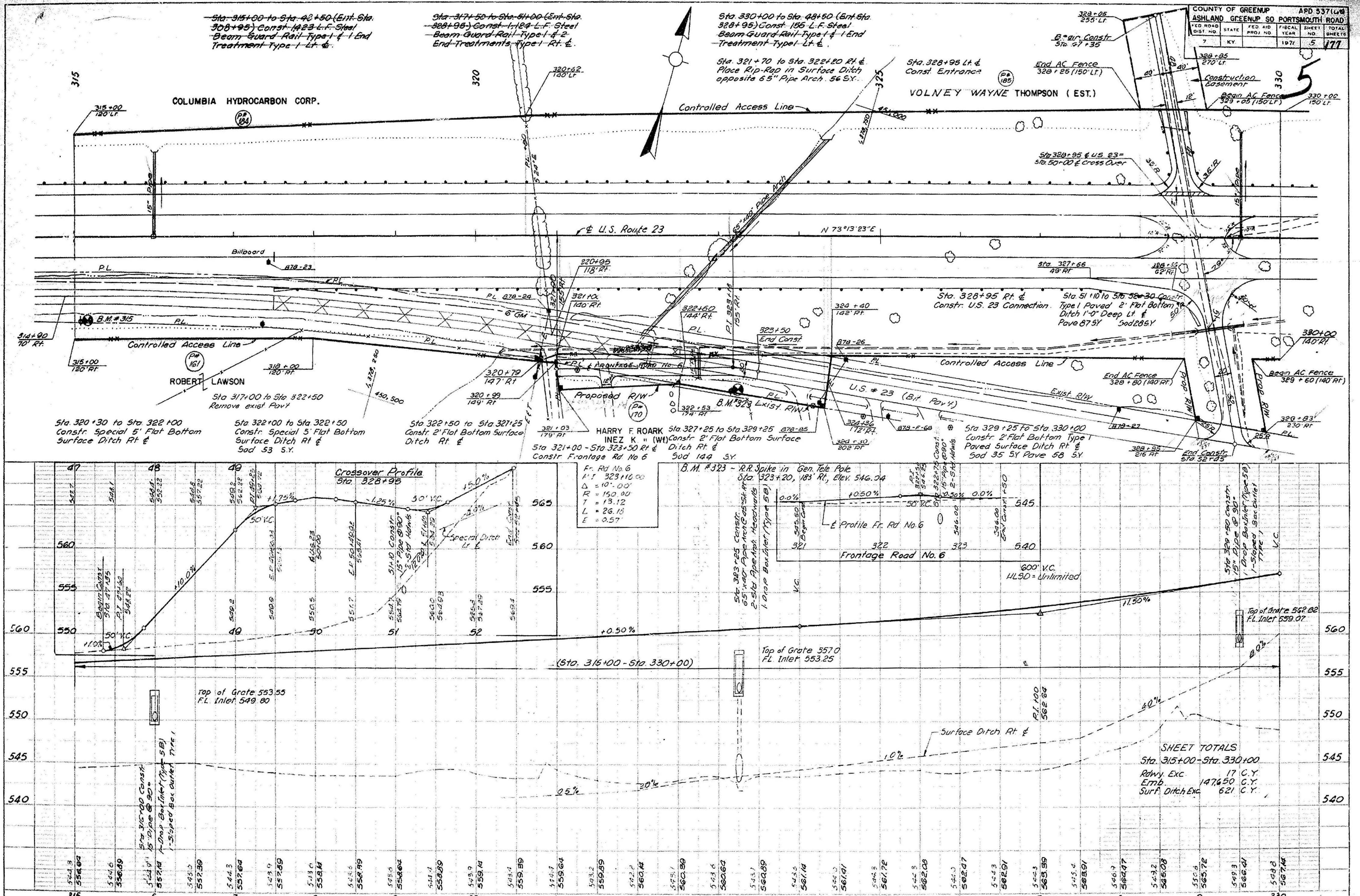
Witness my hand on this the 17 day of Jan 1973

Lisley H Moore
Clerk Greenup County Court

By Mary Stoltz D.C.

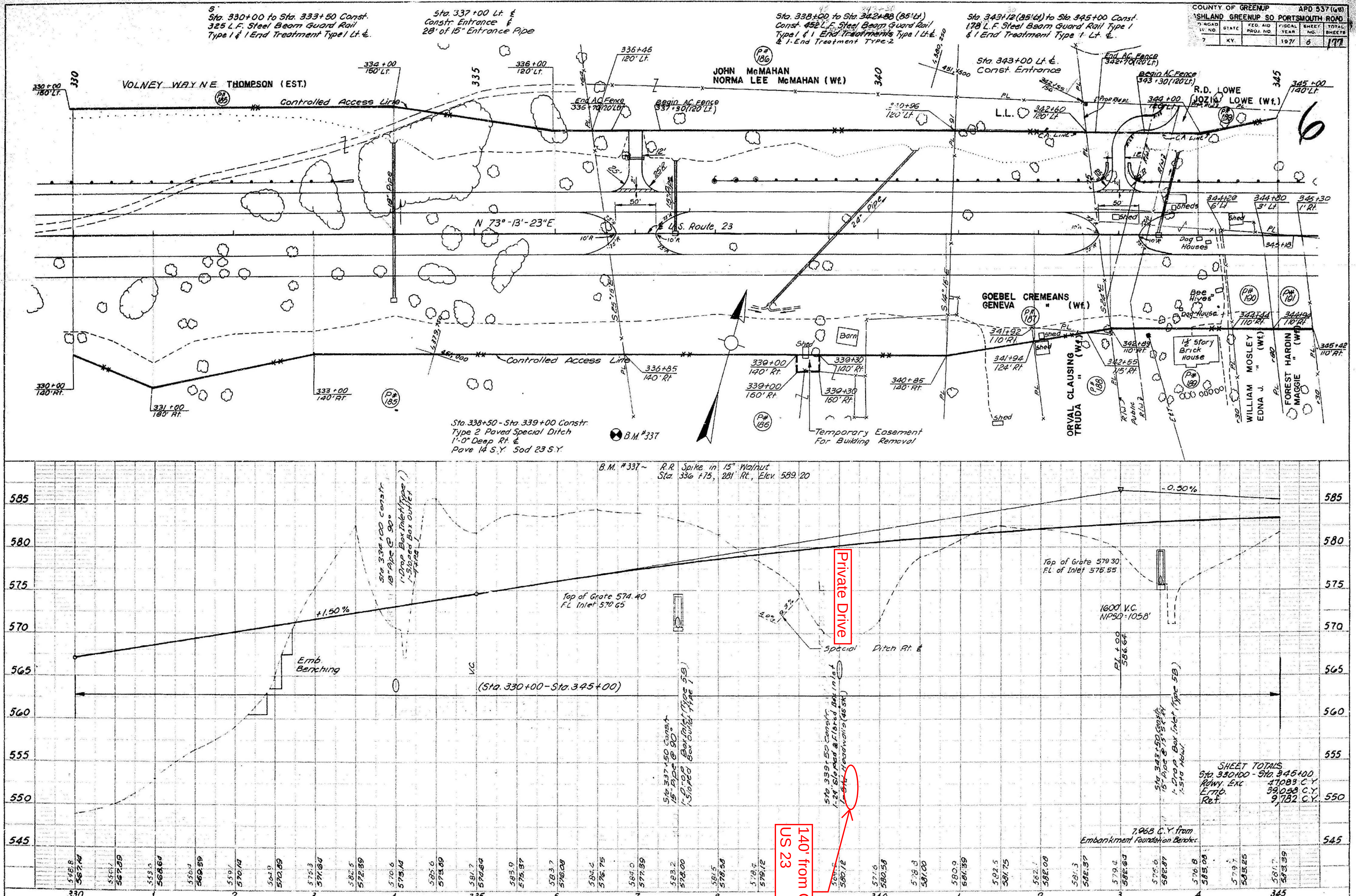
Note: If additional acknowledgements are needed, cross out the above Clerk's Certificate and insert Page 3 of HD 11-37.

107



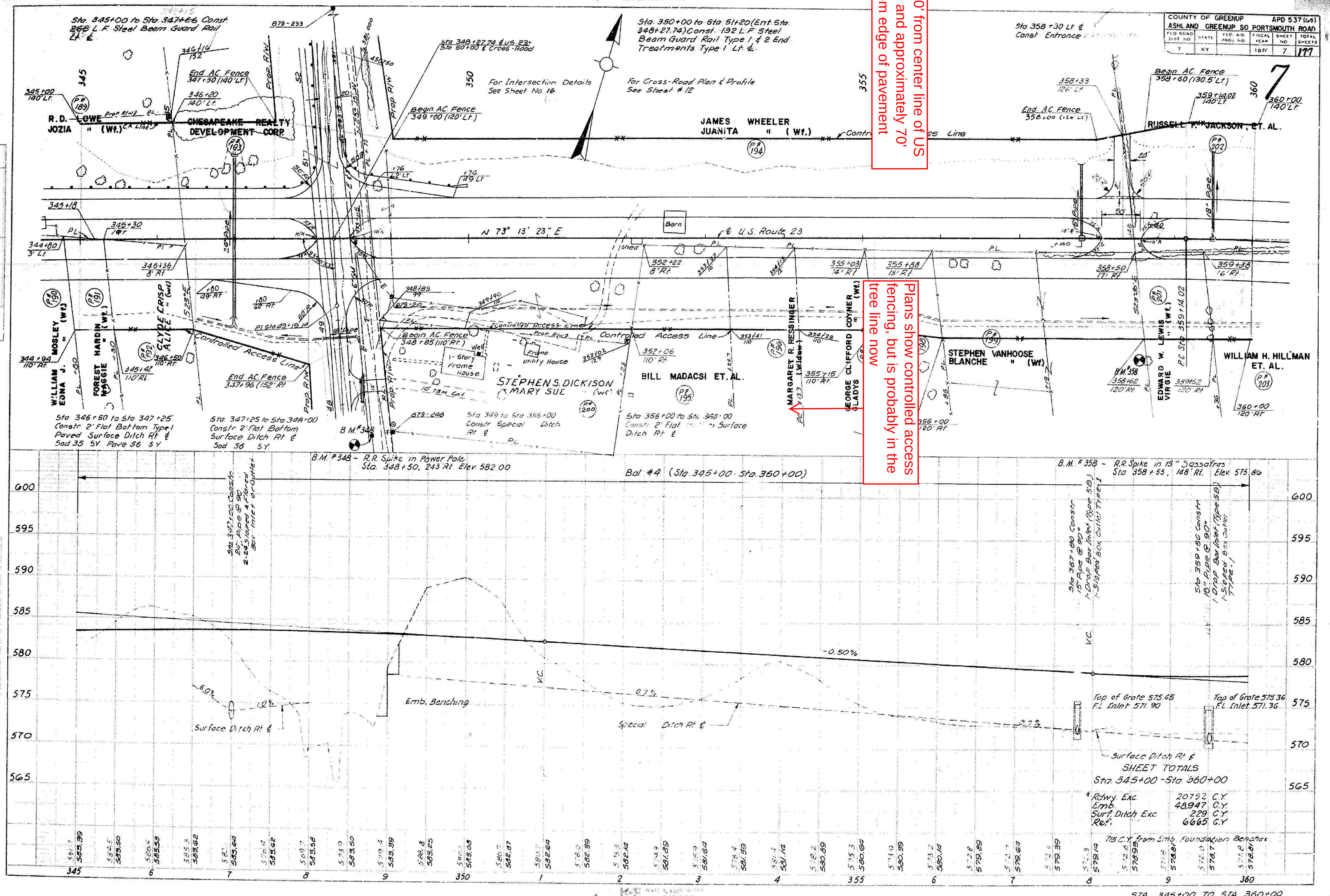
STA. 315+00 TO STA. 330+00

AP 45-211-21

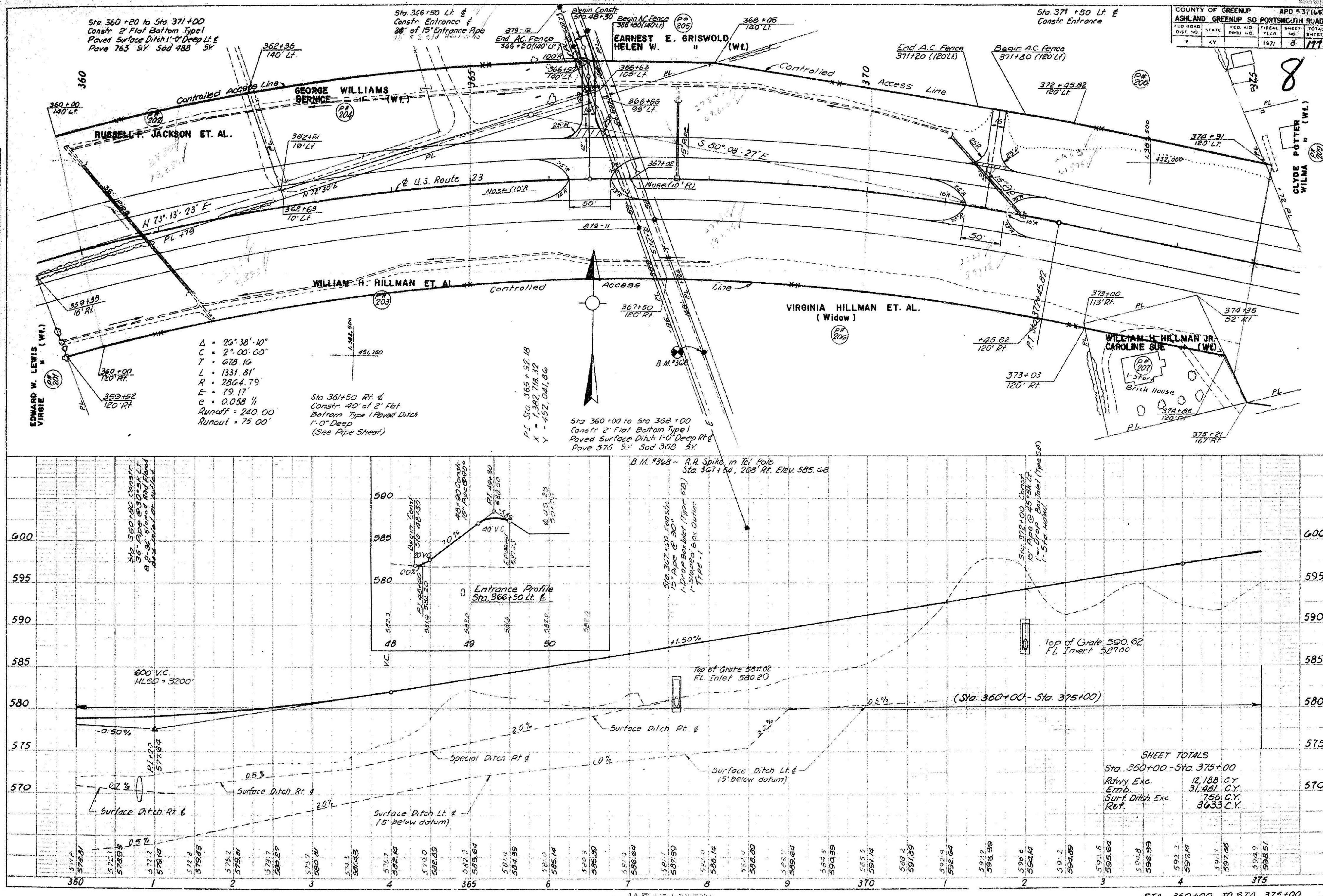


COUNTY OF GREENUP
APD 537 (6)
ASHLAND GREENUP SO PORTSMOUTH ROAD
KY. 1971 6 177
Sta. 330+00 to Sta. 333+50 Const. 325 L.F. Steel Beam Guard Rail Type I & I End Treatment Type I Lt. ℄
Sta. 337+00 Lt. ℄ Constr. Entrance ℄ 28' of 15" Entrance Pipe
Sta. 338+00 to Sta. 342+88 (85'Lt.) Const. 452 L.F. Steel Beam Guard Rail Type I & I End Treatments Type I Lt. ℄ & I End Treatment Type 2
Sta. 343+12 (85'Lt.) to Sta. 345+00 Const. 178 L.F. Steel Beam Guard Rail Type I & I End Treatment Type I Lt. ℄
Sta. 343+00 Lt. ℄ Const. Entrance
VOLNEY WAYNE THOMPSON (EST.)
JOHN McMAHAN
NORMA LEE McMAHAN (Wf.)
R.D. LOWE
JOZIA LOWE (Wf.)
Controlled Access Line
N 73°-13'-23"E
U.S. Route 23
24" Pipe
18" Pipe
GOEBEL CREMEANS
GENEVA (Wf.)
ORVAL CLAUSING
TRUDA (Wf.)
WILLIAM MOSLEY
EDNA J. (Wf.)
FOREST HARDIN
MAGGIE (Wf.)
Barn
Shed
1½ Story Brick House
Bee Hives
Dog Houses
Temporary Easement For Building Removal
Sta. 338+50 - Sta. 339+00 Constr. Type 2 Paved Special Ditch 1'-0" Deep Rt. ℄ Pave 14 S.Y. Sod 23 S.Y.
B.M. #337
B.M. #337 ~ R.R. Spike in 15" Walnut Sta. 336+75, 281' Rt., Elev. 589.20
+1.50%
-0.50%
Emb. Benching
(Sta. 330+00 - Sta. 345+00)
Top of Grate 574.40 F.L. Inlet 570.65
Top of Grate 579.30 F.L. of Inlet 575.55
1600' V.C. NPSD = 1058'
Special Ditch Rt. ℄
Private Drive
140' from Center of US 23
SHEET TOTALS Sta. 330+00 - Sta. 345+00
Rdwy. Exc. 47089 C.Y.
Emb. 39058 C.Y.
Ref. 9782 C.Y.
7,968 C.Y. from Embankment Foundation Benches
STA 330+00 TO STA 345+00

AP 45-211-21


COUNTY OF GREENUP APD 537 (65)
ASHLAND GREENUP SO PORTSMOUTH ROAD
7 KY 1971 7 177
Sta. 345+00 to Sta. 347+66 Const. 266 L.F. Steel Beam Guard Rail Lt. ℄
Sta. 350+00 to Sta. 51+20 (Ent. Sta. 348+27.74) Const. 132 L.F. Steel Beam Guard Rail Type 1 & 2 End Treatments Type 1 Lt. ℄
Sta 348+27.74 ℄ US 23 = Sta 50+00 ℄ Cross-Road
For Intersection Details See Sheet No. 16
For Cross-Road Plan & Profile See Sheet # 12
Sta 358+30 Lt ℄ Const Entrance
120' from center line of US 23 and approximately 70' from edge of pavement
Plans show controlled access fencing, but is probably in the tree line now
N 73° 13' 23" E
℄ U.S. Route 23
R.D. LOWE JOZIA " (Wf.)
CHESAPEAKE REALTY DEVELOPMENT CORP.
JAMES WHEELER JUANITA " (Wf.)
RUSSELL F. JACKSON, ET. AL.
WILLIAM J. MOSLEY EDNA (Wf.)
FOREST HARDIN MAGGIE (Wf.)
CLYDE CRISP ALICE " (Wf.)
STEPHEN S. DICKISON MARY SUE (Wf.)
BILL MADACSI ET. AL.
MARGARET R. RESSINGER (Widow)
GEORGE CLIFFORD COYNER GLADYS (Wf.)
STEPHEN VANHOOSE BLANCHE " (Wf.)
EDWARD W. LEWIS VIRGIE " (Wf.)
WILLIAM H. HILLMAN ET. AL.
Controlled Access Line
B.M. # 348 ~ R.R. Spike in Power Pole Sta. 348+50, 243' Rt. Elev. 582.00
B.M. # 358 ~ R.R. Spike in 15" Sassafras Sta 358+55, 148' Rt. Elev. 575.86
Bal #4 (Sta. 345+00 - Sta. 360+00)
-0.50%
Emb. Benching
Surface Ditch Rt ℄
Special Ditch Rt ℄
SHEET TOTALS Sta. 345+00 - Sta. 360+00
Rdwy. Exc. 20752 C.Y.
Emb. 48,947 C.Y.
Surf. Ditch Exc. 229 C.Y.
Ref. 6665 C.Y.
715 C.Y. from Emb. Foundation Benches
STA 345+00 TO STA 360+00

AP 45-211-21


COUNTY OF GREENUP
APD 537(65)
ASHLAND GREENUP SO PORTSMOUTH ROAD
FED. ROAD DIST. NO. 7
STATE KY
FISCAL YEAR 1971
SHEET NO. 8
TOTAL SHEETS 177
8
Sta 360+20 to Sta 371+00
Constr 2' Flat Bottom Type I
Paved Surface Ditch 1'-0" Deep Lt ℄
Pave 763 SY Sod 488 SY
Sta 366+50 Lt ℄
Constr Entrance
28' of 15" Entrance Pipe
Begin Constr. Sta 48+30
Begin AC Fence 366+80 (140' Lt)
End AC Fence 366+20 (140' Lt)
EARNEST E. GRISWOLD
HELEN W. " (Wf.)
368+05 140' Lt.
Sta 371+50 Lt ℄
Constr Entrance
End A.C. Fence 371+20 (120' Lt)
Begin A.C. Fence 371+80 (120' Lt)
372+45.82 120' Lt.
Controlled Access Line
GEORGE WILLIAMS
BERNICE " (Wf.)
RUSSELL F. JACKSON ET. AL.
360+00 140' Lt.
362+36 140' Lt.
362+61 10' Lt.
362+63 10' Lt.
366+63 105' Lt.
366+66 95' Lt.
367+02
S 80° 08' 27" E
N 73° 13' 23" E
℄ U.S. Route 23
Nose (10' R)
50'
879-11
374+91 120' Lt.
CLYDE POTTER
WILMA " (Wf.)
WILLIAM H. HILLMAN ET. AL.
359+38 16' Rt.
360+00 120' Rt.
359+52 120' Rt.
EDWARD W. LEWIS
VIRGIE " (Wf.)
367+50 120' Rt.
VIRGINIA HILLMAN ET. AL. (Widow)
375+00 113' Rt.
374+35 52' Rt.
WILLIAM H. HILLMAN JR.
CAROLINE SUE " (Wf.)
1-Story Brick House
374+86 120' Rt.
375+21 167' Rt.
+45.82 120' Rt.
373+03 120' Rt.
P.T. Sta 372+45.82
Δ = 26° 38' 10"
C = 2° 00' 00"
T = 678.16
L = 1331.81'
R = 2864.79'
E = 79.17
e = 0.058 '/'
Runoff = 240.00'
Runout = 75.00'
Sta 361+50 Rt ℄
Constr 40' of 2' Flat Bottom Type I Paved Ditch 1'-0" Deep
(See Pipe Sheet)
P.I. Sta 365+52.18
X = 1,382,718.32
Y = 452,041.86
Sta 360+00 to Sta 368+00
Constr 2' Flat Bottom Type I
Paved Surface Ditch 1'-0" Deep Rt ℄
Pave 576 SY Sod 368 SY
B.M. #368 ~ R.R. Spike in Tel. Pole
Sta 367+50, 208' Rt. Elev. 585.68
Entrance Profile
Sta. 366+50 Lt ℄
600' V.C.
HLSD = 3200'
-0.50%
+1.50%
P.I. 1+20 577.84
Top of Grate 584.02
FL Inlet 580.20
Top of Grate 590.62
FL Invert 587.00
(Sta. 360+00 - Sta. 375+00)
Surface Ditch Rt ℄
Surface Ditch Lt ℄ (5' below datum)
Special Ditch Rt ℄
SHEET TOTALS
Sta. 360+00 - Sta. 375+00
Rdwy Exc. 12,188 C.Y.
Emb. 31,461 C.Y.
Surf Ditch Exc. 756 C.Y.
Ref. 3633 C.Y.
PLAN
PROFILE
STA 360+00 TO STA 375+00

AP 45-211-21

Mailed
Paul D Gibson
Rt 1 Box 421 D
South Shore Ky

3-12-91
MM

DB 392 / 356

THIS DEED OF CONVEYANCE made and entered into on this the 2 day of March, 1991, by and between JOHN C. MCMAHAN and NORMA LEE MCMAHAN, his wife, of P.O. Box 1002, South Shore, Greenup County, Kentucky, parties of the first part, and PAUL D. GIBSON, of Route 1, Box 421D, South Shore, Greenup County, Kentucky, parties of the second part.

WITNESSETH: That for and in consideration of the sum of ONE ($1.00) DOLLAR, cash in hand paid, and other good, valuable and sufficient consideration, the receipt of which is hereby acknowledged, the parties of the first part do hereby grant, bargain, sell and convey unto the party of the second part, his heirs and assigns forever, the following described real estate, to-wit:

Situate in Greenup County, Kentucky, and described as follows:

KY. STATE TAX PAID 5.00
DATE 3-9-91
DONALD L. [illegible], CLERK
GREENUP COUNTY
BY ______ D.C.

BEGINNING at a stake and near a railroad crossing on New U. S. 23, S 18-10 E, a distance of 263.3 feet to a steel post; thence S 82-25 W, a distance of 500 feet to a steel post; Thence N 7-30 W, a distance of 248 feet to a stake; thence N 81-00 E, a distance of 451.00 feet to the point of Beginning, containing 2.79 acres, as shown on plat attached hereto and made a part hereof.

Being the same real etsate conveyed to John C. McMahan and Norma Lee McMahan, his wife, by Louann M. Hammond, single, by deed dated May 5, 1986, of record in the Office of the Clerk of the Greenup County Court of Kentucky, in Deed Book 353, Page 559.

The full consideration for this conveyance is $5,000.00.

The foregoing real estate is conveyed subject to all restrictive covenants, easements and reservations, if any, previously imposed and appearing of record.

TO HAVE AND TO HOLD the same, together with all rights, privileges and appurtenances thereunto belonging or in anywise appertaining unto the party of the second part, his heirs and assigns forever with covenants of General Warranty.

IN WITNESS WHEREOF, the parties of the first part have hereunto subscribed their names as of the date first above written.

John McMahan
JOHN C. MCMAHAN

Norma Lee McMahan
NORMA LEE MCHAHAN

STATE OF OHIO)

COUNTY OF SCIOTO)

The foregoing instrument was acknowledged before me on this the

8th day of March, 1991 by John C. McMahan, married.

My Commission expires: 3-9-91

NOTARY PUBLIC
STATE AND COUNTY
AFORESAID

357

STATE OF KENTUCKY)

COUNTY OF GREENUP)

The foregoing instrument was acknowledged before me on this the 8th day of March, 1991, by Norma Lee McMahan, married.

Commission expires: 10-26-1994

THIS INSTRUMENT PREPARED BY:

Michael C. Wilson

MICHAEL C. WILSON
ATTORNEY AT LAW
800 Diederich Blvd.
Russell, KY 41169

CONSIDERATION CERTIFICATE

We, JOHN C. MCMAHAN and NORMA LEE MCMAHAN, his wife, Grantors and PAUL D. GIBSON, Grantee, do hereby certify, pursuant to KRS Chapter 382, that the above-stated consideration in the amount of $5,000.00, is the true, correct and full consideration paid for the property herein conveyed. We further certify our understanding that falsification of the stated consideration or sale price of the property is a Class D Felony, subject to one to five years imprisonment and fines up to $10,000.00.

Paul D. Gibson
PAUL D. GIBSON
GRANTEE

John McMahan
JOHN C. MCMAHAN

Norma Lee McMahan
NORMA LEE MCMAHAN

STATE OF OHIO)
COUNTY OF SCIOTO)

The foregoing Consideration Certificate was acknowledged and sworn to before me on this the 8th day of March, 1991, by JOHN C. MCMAHAN, married.

My Commission expires: 3-9-1991

Wanda Bennington
NOTARY PUBLIC

STATE OF KENTUCKY)
COUNTY OF GREENUP)

The foreging Consideration Certificate was acknowledged and sworn to before me on this the 8th day of March 1991, by NORMA LEE MCMAHAN, married.

My Commission expires: 10-26-1994

Mary Hitchcow
NOTARY PUBLIC

359

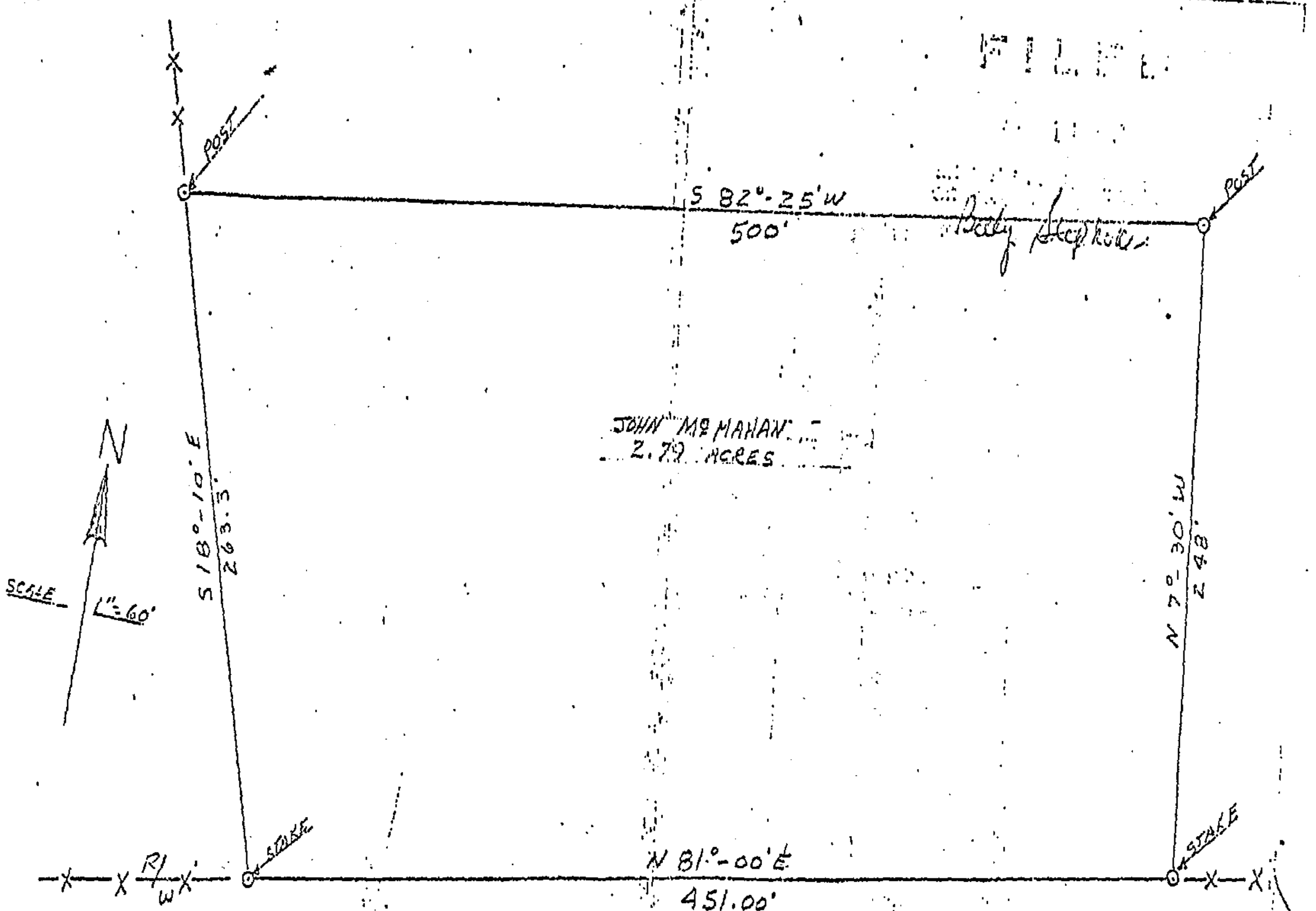
STATE OF KENTUCKY)

COUNTY OF GREENUP)

The foregoing instrument was acknowledged before me on this the 8th day of March, 1991, by Paul D. Gibson, Grantee.

My Commission expires: 10-26-1994

Mary Withrow
NOTARY PUBLIC


FILED
S 82°-25'W
500'
POST
POST
JOHN McMAHAN
2.79 ACRES
S 18°-10'E
263.3'
N 7°-30'W
248'
N
SCALE 1"=60'
STAKE
STAKE
N 81°-00'E
451.00'
R/W

361

STATE OF KENTUCKY
COUNTY OF GREENUP .... SCT.

I, Donald L. Davidson, Clerk of the Greenup County Court, do certify that the foregoing Deed was on the 9 day of March, 1991, at 10:20 o'clock Am lodged in my office for record, and that it, the foregoing, and this certificate have been recorded in my said office.

Witness my hand this 9 day of March, 1991

DONALD L. DAVIDSON, Clerk
By Mary Steele D.C.

362

Jimmie + Verna Williams

DEED

THIS DEED OF CONVEYANCE, made and entered into this 25th day of September, 2009, by and between Scott Williams, in his capacity as executor of the Estate of James R. Williams (AKA Jimmie R. Williams), Scott Williams and Michelle Williams, husband and wife, with a mailing address of 5482 State Route 7, South Shore, KY 41175, Vickie Click and Barry Click, husband and wife, with a mailing address of P.O. Box 125 South Shore, KY 41175, Kris Williams and Dusty Williams, husband and wife, with a mailing address of 28212 U.S. 23, South Shore, KY 41175, Jeannie Williams Ford, single, with a mailing address of 3478 U.S. Route 23, Chillicothe, OH 45601, and Deborah Williams, single, with a mailing address of 257 Lafayette Lane, Franklin Furnace, OH, 45629 **GRANTORS**, and Paul D. Gibson and Kimberly Gibson, husband and wife, with a mailing address of 38 First Street, South Shore, KY 41175, **GRANTEES**.

TAXES FOR THE YEAR 2009 AND SUBSEQUENT YEARS SHOULD BE MAILED TO:

38 First Street, South Shore, KY 41175 ATTN: Paul Gibson

WITNESSETH:

THAT FOR AND IN CONSIDERATION of the sum of FORTY-EIGHT THOUSAND and NO/100ths DOLLARS ($48,000.00), payment and receipt of which is hereby acknowledged, the Grantors do hereby grant, bargain, sell and convey unto the Grantees, for their joint lives, with remainder in fee simple to the survivor, his or her heirs and assigns forever, the following described real estate situate in Greenup County, Kentucky, to-wit:

Lying and being at Sand Hill, approximately 3 miles east of South Shore, Greenup County, Kentucky and lying north of US Highway No. 23 and particularly described as follows: BEGINNING at a point in the C&O right of way line, thence with the C&O right of way line, thence with eh C&O right of way line S. 76°-25'-W. 775 ft; thence with the Thompson line S. 17°-10'E. 384 ft.; thence north 80° 50'-E 499 ft.; thence S.8°-15'-E.; 205 ft. thence N 80° 15' E 519.5 ft. ; thence N 17°-20'W. 240.5 ft.; thence with the Rice line S 76°-00' 210.3 ft.; thence with the Rice line N. 17° -50' W. 435 ft. to the place of beginning.

Being the same real estate conveyed from R. D. Lowe and Joza Lowe, husband and wife, to Jimmie R. Williams and Verna Williams, husband and wife, by deed dated September 29, 1969 and appearing of record in Deed Book 254, Page 487 in the Office of the Greenup County Court Clerk. The said Verna ~~Lowe passed~~ away on April 20, 2006, thereby vesting all of her interest in the property in her husband, Jimmie R. Williams by survivorship. The said Jimmie R. Williams also passed away on April 26, 2008, intestate. The Grantors herein claim title by right of inheritance. See Affidavit of Descent of James R. Williams (AKA Jimmie R. Williams), dated _________, appearing of record in Deed Book D556, Page 34 in the office of the Greenup County Court Clerk.

The foregoing real estate is conveyed subject to all restrictions, reservations, easements, covenants and conditions, if any, previously imposed and appearing of record.

TO HAVE AND TO HOLD the same, together with all rights, privileges, appurtenances, and improvements thereunto belonging or in anywise appertaining unto the Grantees, for their joint lives, with remainder in fee simple to the survivor, his or her heirs and assigns forever, with covenants of General Warranty.

The parties hereto further certify, pursuant to K.R.S. 382.135, that the above-stated consideration in the amount of FORTY-EIGHT THOUSAND and NO/100ths DOLLARS ($48,000.00), is the true, correct, and full consideration paid for the property herein conveyed.

IN TESTIMONY WHEREOF, the Grantors and Grantees have executed this instrument and hereunto subscribed their names, the day and date first above written.

Scott R Williams

SCOTT WILLIAMS, in his capacity as Executor of the Estate of James R. Williams

(AKA Jimmie R. Williams).

Scott R Williams

SCOTT WILLIAMS, individually,Grantor

Michelle Williams

MICHELLE WILLIAMS, Grantor

Vickie L Click

VICKIE CLICK, Grantor

Barry O Click / Vickie L Click POA

BARRY CLICK, Grantor

Kris Williams

KRIS WILLIAMS, Grantor

Dusty Williams

DUSTY WILLIAMS, Grantor

Jeannie Williams Ford

JEANNIE WILLIAMS FORD, Grantor

Deborah Williams

DEBORAH WILLIAMS, Grantor

Paul D. Gibson

PAUL D. GIBSON, Grantee

Kimberly Gibson

KIMBERLY GIBSON, Grantee

GREENUP COUNTY
D556 PG42

COMMONWEALTH OF KENTUCKY)
(
COUNTY OF Greenup)

I, a Notary Public in and for the aforesaid county and state, do hereby certify that the foregoing Deed of Conveyance was this day before me in my said county and state, duly executed, acknowledged, subscribed and sworn to by Scott Williams in his capacity as Executor of the Estate of James R. Williams (AKA Jimmie R. Williams) to be his free act and deed and the free act and deed of the Estate of James R. Williams (AKA Jimmie R. Williams).

This 18 day of Sept, 2009.

Notary Public, State-at-Large, KY
My Commission expires: Nov 4 2009

COMMONWEALTH OF KENTUCKY)
(
COUNTY OF Greenup)

I, a Notary Public in and for the aforesaid county and state, do hereby certify that the foregoing Deed of Conveyance was this day before me in my said county and state, duly executed, acknowledged, subscribed and sworn to by Scott Williams and Michelle Williams, husband and wife, as Grantors, to be their free act and deed.

This 18 day of Sept 2009.

Notary Public, State-at-Large, KY
My Commission expires: Nov 4 2009

COMMONWEALTH OF KENTUCKY)
(
COUNTY OF Greenup)

I, a Notary Public in and for the aforesaid county and state, do hereby certify that the foregoing Deed of Conveyance was this day before me in my said county and state, duly executed, acknowledged, subscribed and sworn to by Vickie Click and Barry Click, husband and wife, as Grantors, to be their free act and deed.

This 22 day of September 2009.

Notary Public, State-at-Large, KY

COMMONWEALTH OF KENTUCKY)
(
COUNTY OF Carter)

I, a Notary Public in and for the aforesaid county and state, do hereby certify that the foregoing Deed of Conveyance was this day before me in my said county and state, duly executed, acknowledged, subscribed and sworn to by Kris Williams and Dusty Williams, husband and wife, as Grantors, to be their free act and deed.

This 25th day of September, 2009.

Notary Public, State-at-Large, KY
My Commission expires: 10-16-2012

COMMONWEALTH OF KENTUCKY)
(
COUNTY OF Greenup)

I, a Notary Public in and for the aforesaid county and state, do hereby certify that the foregoing Deed of Conveyance was this day before me in my said county and state, duly executed, acknowledged, subscribed and sworn to by Jeannie Williams Ford, single, as Grantor, to be her free act and deed.

This 18 day of Sept, 2009.

Notary Public, State-at-Large, KY
My Commission expires: Nov 4 2009

COMMONWEALTH OF KENTUCKY)
(
COUNTY OF Greenup)

I, a Notary Public in and for the aforesaid county and state, do hereby certify that the foregoing Deed of Conveyance was this day before me in my said county and state, duly executed, acknowledged, subscribed and sworn to by Deborah Williams, single, as Grantor, to be her free act and deed.

This 18 day of Sept, 2009.

Notary Public, State-at-Large, KY
My Commission expires: Nov 4 2009

COMMONWEALTH OF KENTUCKY)
(
COUNTY OF Carter)

I, a Notary Public in and for the aforesaid county and state, do hereby certify that the foregoing Deed of Conveyance was this day before me in my said county and state, duly executed, acknowledged, subscribed and sworn to by Paul D. Gibson and Kimberly Gibson, husband and wife, as Grantees, to be their free act and deed.

This 25th day of September, 2009.

Notary Public, State-at-Large, KY
My Commission expires: 10-16-2012

I hereby certify that this instrument has been prepared by: of

STEPHANIE LOTHER HEMBROFF
Attorney-at-Law
751 Bellefonte Road, Suite 2
Flatwoods, Kentucky 41139
(606) 833-9462

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DEED

THIS DEED OF CONVEYANCE, made and entered into by and between FRANK H. WARNOCK and MATTHEW J. WARNOCK, TRUSTEES for FRANK H. WARNOCK, MATTHEW J. WARNOCK, ANNA MICHELLE WARNOCK and CAROLYN P. WARNOCK, whose address is P.O. Box 617, Greenup, Kentucky, parties of the first part, and FRANK H. WARNOCK, MATTHEW WARNOCK, ANNA M. NEAL (formerly known as Anna Michelle Warnock) and CAROLYN P. WARNOCK, of P.O. Box 617, Greenup, Kentucky 41144, parties of the second part,

WITNESSETH: That for and in consideration of the sum of ONE ($1.00) DOLLAR, cash in hand paid, and pursuant to the terms of a Trust as set forth in Deed Book 429, Page 199 and Deed Book 441, Page 74, which terms required the termination of Trust and execution of this deed to the four (4) Grantees, individually and free of Trust, and other good and valuable considerations, the receipt of which is hereby acknowledged, the parties of the first part have granted, bargained and sold, and by these presents do hereby grant, bargain, sell and convey unto the parties of the second part, their heirs and assigns, forever, the following described real estate and interests and ownership in and to the real estate lying in Greenup County, Kentucky, to-wit:

I.

An undivided 1/7 interest, title and ownership in and to the following described tracts of real estate situated in or near Siloam in Greenup County, Kentucky, and consisting of two parcels described as follows:

PARCEL NO. I
BEGINNING at a point in the North right-of-way line of the Chesapeake & Ohio Railway Company, corner to property of the Chesapeake Realty Development Corporation; thence with the right of way of the Chesapeake & Ohio Railway Company, South 70 degrees 46'30" West 1559.72 feet, more or less, to the line of Columbia Hydrocarbon Corporation; thence with the line of Columbia Hydrocarbon Corporation, North 23 degrees 43'30" West 4473.45 feet, more or less, to the low water mark of the Ohio River; thence with the low water line of the Ohio River, North 61 degrees 54'48" East 1535.37 feet, more or less, to the property line of the Chesapeake Realty Development Corporation; thence with said line, South 24°01 East 4712.65 feet, more or less, to the point of BEGINNING, containing 162.8 acres, more or less.

PARCEL NO. II
BEGINNING at a point on the South right-of-way line of the Chesapeake & Ohio Railway Company, opposite the corner between Parcel No. 1 and the Columbia Hydrocarbon tract on the North side of the Railway; thence with the South right-of-way line of the Chesapeake & Ohio Railway Company, North 70 degrees 46'30" East 1560.27 feet, more or less, to a point directly opposite the beginning corner of Tract No. I on the North side of the Railway; thence South 24°10' East as unmeasured distance to the right-of-way line of new U. S. Highway #23; thence with the right-of-way line of new U.S.. Highway #23, a Southwesterly direction 1560 feet,

more or less, to the fence, the west property line of the Volney Wayne Thomson tract; thence North 23 degrees 11' 30" West an unmeasured distance to the right-of-way line of the Chesapeake & Ohio Railway Company, the point of BEGINNING, containing 20 acres, more or less.

The above described real estate is the same real estate described and conveyed in the Deed from SECOND NATIONAL BANK, Ashland, Kentucky, as Trustee of the Volney Wayne Thomson Trust, to FRANK K. WARNOCK, ET ALS, by Deed dated March 24, 1978, and recorded in Deed Book 308, Page 246, of the Deed Records in the Office of the Greenup County Clerk. Thereafter, Frank K. Warnock having deeded 3/28 ownership to this Trust in Deed Book 429, Page 199, and the remaining 1/28 to this Trust in Deed Book 441, Page 74, thereby vesting this Trust with the 1/7 interest herein conveyed.

II.

An undivided 3/14 interest, title and ownership in and to the following tract described tracts of real estate situated on East Tygart Road and on the waters of Lick Branch, Greenup County, Kentucky, and consisting of Parcels described as follows:

<u>TRACT NO. I</u>: Being a small parcel of land situated on the East Tygart road, corner to lands conveyed by the grantors (former) herein to Garold M. Vaughn; thence with said Vaughn property, South 88-30 East 325 feet; thence due South 233 feet; thence with lands now or formerly owned by Jesse Lawson, a Westerly direction with said Lawson lines to the East Tygart Road; thence with the East Tygart road a Southerly direction approximately 71 feet (not measured) to the point of beginning.

<u>TRACT II</u>: Being all of the hill land formerly owned by William Glover and Minnie S. Glover not heretofore conveyed, and BEGINNING at a corner of the Glover tract with the lands of Clifford Budig near Bear Branch; thence running with the meanders of the Budig line a Northeasterly direction to the corner between Budig and Carl Rhoden and the Glover lands; thence continuing with the line of Carl Rhoden, a Northeasterly direction to the lands formerly owned by Robert Johnson and Doris Johnson, and now owned by Margaret McAllister and Judy Morton; thence with McAllister and Morton line with the meanders thereof to the corner between Glover and the said McAllister and Morton and the George Williams tract; thence with the George Williams tract, a Southwesterly direction to the corner between Williams, Glover and Clyde Potter; thence with lines of Potter, following the meanders thereof to the line of Jesse Lawson; thence following the Lawson line to the lands of Garold M. Vaughn; thence a line generally parallel with the East Tygart Road and approximately 200 feet distant therefrom, passing the back lines of Garold Vaughn, Milton Williams, Gilbert Nickel or his grantees, and the Marvin Lewis line to the point of beginning.

IT IS THE INTENTION of the grantors (formerly) to convey to the grantee all of the remaining lands which the Glovers inherited as heirs of William M. Glover and Minnie S. Glover remaining unsold in Greenup County, Kentucky, whether correctly described herein or not, and supposed to contain approximately 108 acres, but sold by the boundary and not the acre.

<u>TRACT III</u>: Situated near Siloam on the waters of Lick Branch in Greenup County, Kentucky, BEING that parcel of land and interest in land lying south and southwest of the center of the Siloam-Mt. Ebo Road conveyed to Volney Wayne Thomson by deed from Perlina Thomson dated July 5, 1938, and of record in Deed Book 86, Page 371, Greenup County Court Clerk's Office, and described in said deed as Tract No. 3, and to which deed reference is made for further description and additional sources of title.

The mineral rights referred to in the description contained in the foregoing deed which were reserved in and to a tract of land consisting of approximately 66 2/3 acres sold and conveyed to Matilda Wooten by deed of Volney E. Thomson and Nancy S. Thomson dated June 6, 1913, and of record in Deed Book 44, Page 82, Greenup County Court Clerk's Office, are specifically conveyed by the party of the first part to the parties of the second part by this conveyance.

This conveyance includes all rights and benefits in and to any outstanding leases or contracts concerning the above described real estate and is subject to all rights transferred to others.

The above described real estate is described and conveyed in the following deeds:

(1) Deed from Second National Bank, Ashland, Kentucky, as Trustee of the Volney Wayne Thomson Trust, to FRANK K. WARNOCK, ET ALS, by Deed dated November 24, 1978, recorded in Deed Book 313, Page 354, Office of the Greenup County Clerk.

(2) Deed from J J J R ENTERPRISES, INC., a Kentucky Corporation to JOHN R. McGINNIS (1/7 undivided interest), ROGER OSBORNE (1/7 undivided interest); J. D. ATKINSON (1/7 undivided interest), JAMES E. ARMSTRONG (1/7 undivided interest); FRANK K. WARNOCK (1/7 undivided interest); and GEORGE ARRINGTON (1/7 undivided interest), by deed dated December 8, 1978, recorded in Deed Book 313, Page 496, Office of the Greenup County Clerk.

(3) Deed from ROGER OSBORNE and SHIRLEY OSBORNE, his wife, to FRANK K. WARNOCK and JOHN R. McGINNIS, by Deed dated June 6, 1980, recorded in Deed Book 322, Page 337, Office of the Greenup County Clerk.

III.

An undivided 1/3 interest, title and ownership in and to the following tract of real estate situated on the waters of Buck Run in Greenup County, Kentucky, and described as follows:

Beginning at a stone on Buck Run N. 15 E. 131 Poles to 2 White Oaks & Black Oak N. 45 W. 81 Poles to J. Bovles & Andersons corner a white oak, N. 42 W. 4 poles to stake, a Black Oak bearing S. 38 E. 11 links, N. 47 E. 7 Poles N. 80 W. 9 1/4 Poles, east 17 poles to a gum, N. 87 E. 15 1/2 Poles to C. 0. Stump, N. 83 E. 10 poles, S. 87 E. 10 poles to a Red Oak, N. 60 E. 7 1/2 Poles to White Oak N. 66 E. 9 Poles to chestnut, N. 51 E. 5 Poles to Chestnut Oak, S. 75 E. 7 Poles, S. 82 E. 8 Poles to Black Oak, S. 85 E. 18 1/2 poles to Black Oak, S. 82 E. 8 poles to Hickory, S. 54 E. 11 Poles to White Oak, same course 14 Poles to Pine, N. 64 E. 23 1/2 Poles to chestnut Oak, Parmers corner; S. 67 E. 23 poles to two Black Oaks S. 20 E. 23 Poles to White Oak, S. 35 E. 18 poles, S. 76 E. 7 poles to Black Oak; S. 44 E. 26 Poles to White Oak, S. 66 E. 10 poles, S. 80 E. 22 1/2 Poles to Red Oak, S. 46 E. 28 poles, S. 59 W. 31 poles to White Oak, S. 54 W. 14 3/4 Poles to Sourwood, S.'69 W. 19 poles to stake, S. 51 W. 19 poles to pine, on ridge, S. 43 W. 7 poles to black oak, Eastham's corner, West 9 1/2 poles, N. 74 W. 20 poles to black oak, S. 63 W. 4 1/2 poles, S. 38 W. 17 1/2 poles to Black Oak, S. 15 E. 69 poles to hickory & Stone, S. 17 W. 18 poles to gum, S. 87 1/2 W. 17 1/2 poles to Black Oak, S. 77 W 12 1/2 Poles to Chestnut, S. 80 W. 18 poles to Black Oak, S. 68 W. 12 1/2 Poles to black oak, West 13 1/2 poles to red oak, N. 80 W. 21 poles to black oak, N. 63 W. 61 Poles to the beginning.

This conveyance and the above described real estate is subject to a transmission line easement granted to East Kentucky Power Cooperative, Inc., by Easement dated August 22, 1988, recorded in Deed Book _____, Page_____, Office of the Greenup County Clerk.

Being the same real estate conveyed by HERBERT BOYLES and LAVERNE BOYLES, his wife, to JOHN R. McGINNIS, FRANK K. WARNOCK, and W.

TERRY McBRAYER, by Deed dated September 16, 1977, and recorded in Deed Book 305, Page 119, Office of the Greenup County Clerk.

IV.

A 1/4th undivided fee simple interest and ownership in and to the following described real estate:

FIRST TRACT: BEGINNING at the southwest corner of the County Road bridge crossing at Big Rocky Branch; thence up said branch with the line of John McNeal, as agreed N 19 W 7 1/2 poles to an elm stump on bank of the branch, N 29 1/2 W 45 poles to an elm; N 18 1/2 W 22 poles to a rock in the branch N 3 W 31 8/10 poles to a chestnut; N 10 W 36 poles; N 54 W 39 poles to a black walnut; N 33 3/4 W 24 poles to a beech; N 33 W 24 6/10 poles to two buckeyes; N 44 3/4 W 24 poles to a sycamore; N 40 W 14 poles to a beech; N 50 W 38 poles to a stone on south bank of branch 20 links S 15 1/2 W from honey locust on north bank of branch, corner with John McNeal, and Merrill; thence with Merrill line S 48 94 poles to a large lime rock, corner of McClave tract; and with its line S 23 1/2 E 50 1/2 poles to a set stone by a dogwood stump, corner of E. E. Gahan, and with her lines S 73 E 21 poles to a black oak S 20 E crossing hollow 53 poles to a stone on top of ridge S 36 W 24 1/4 poles to a stone, two white oaks and two hickorys bushes, S 54 E 78 plles to a hickory S 62 E 31 poles to a tripple black walnut; S 65 E 14 poles to a stone; S 52 E 24 1/4 poles to a stone on ridge; thence down the hill S 72 ½ E. 36 poles to a stone on hillside, corner of Wilmer Smith, and with her lines N 83 3/4 E 12 poles to a stone set on upper side of County Road; and with the road N 6 1/4 W 10 poles N 13 1/2 E 18 poles N 50 E 3 poles to the beginning, containing 180 acres.

Reserving a right of way for road over the land from the line of E. E. Gahan down the branch to the County Road.

SECOND TRACT: BEGINNING at the center of the Railway tract over the culvert crossing Big Rocky Branch; thence with the center of Railway tract S 4 W 16 poles; S 1 3/4 W. 16 poles S 2 1/2 E 16 poles; thence with the line of E. E. Gahan, east Passing stone set a Railway fence at 1 1/2 poles, 20 poles to the mouth of polecat creek and bank of Ohio River; thence along river bank N 10 1/2 W 56 poles to the mouth of Big Rocky Branch, and up the same S 71 ½ W 20 poles to the beginning, containing 8 acres; also conveying all the land between the lines to low water mark of the Ohio River, and right of way for road across the land of E. E. Gahan, crossing the Railway to the county road, and reserving the right of way of the Railway over the tract conveyed.

There are several conveyances to the Chesapeake and Ohio Railway Company, which are excluded from the above description as being conveyed to the Chesapeake and Ohio Railway Company by Deed of Record in the Greenup County Court Records.

There is also excluded from this conveyance, a portion of land conveyed to the Department of Highways, by deeds of record in the Greenup County Court Records.

There is also excepted from the above described real estate the land heretofore conveyed by Colonial Land Development, Inc., to:

(a) Ralph Marcum, et ux, D.B. 305, P. 55;
(b) Stanley Rupert, et ux, D.B. 309, P. 334;
(c) Tom Hatfield, et ux, D.B. 300, P. 196;
(d) Herman C. Senters, et ux, D.B. 309, P. 378;
(e) Jack L. Senters, et ux, D.B. 310, P. 652;
(f) Danny L. Rakes, et ux, D.B. 315, P. 500.

Being part of the same realty conveyed by Roger Osborne et ux, to Frank K. Warnock by Deed dated June 19, 19 and recorded in Deed Book 322, Page 407, Office of the Greenup County Clerk, and also having been described in Deed from Frank K. Warnock, et ux, to Frank H. Warnock, dated July 28, 1980, and recorded in Deed Book 441, Page 71, Office of the Greenup County Clerk.

V.

Being a 1/8th undivided fee simple interest and ownership in and to the following described real estate:

TRACT ONE: BEGINNING at a point in the C. & 0. Railway Company's line 'and the property of Virginia Hannah; thence N. 23°-33' W. a distance of 1440 feet, more or less, to a stake at the Ohio River Bank; thence S. 71°45' W. a distance of 206 feet, more or less, to a point in the line of Bonzo; thence with the line of Bonzo S. 23°-33' E. passing over a stone in said line at the edge of the bank a distance of 1410 feet to a stake a corner of the Virginia Diana Howland line; thence with the Virginia Diana Howland line and the Donna Marie Bradley rive N. 530 E. a distance of 150 feet; thence S. 23°-33' E. a distance of 100 feet to a stake in the C. & 0. Railway Company's line; thence with the line of the C. & 0. Railway Company N. 53°-E. a distance of 56 feet to a point marked by a stake, a corner to the Virginia Hannah property, the place of beginning.

TRACT TWO: BEGINNING at an Elm Tree on the underbank of the Ohio River and being a corner to Parcel No. 6A; thence down the River Bank S. 710-45' W. a distance of 206 feet; thence S. 23°-33' E. a distance of 1440 feet, more or less, to a stake in the line of the C. & 0. Railway Company; thence N. 530 E. a distance of 200 feet a corner to Parcel No. 6A; thence N. 22-55' E. a distance of 1377 feet to the place of beginning.

Being part of the same realty conveyed by Roger Osborne et ux, to Frank K. Warnock by Deed dated June 19, 1980, and recorded in Deed Book 322, Page 407, Office of the Greenup County Clerk, and also having been described in Deed from Frank K. Warnock, et ux, to Frank H. Warnock, dated July 28, 1980, and recorded in Deed Book 441, Page 71, Office of the Greenup County Clerk.

VI.

A complete full 100% ownership in and to the following described real estate lying in Greenup County, Kentucky, to-wit:

The following described tract of land being part of the Oldsteam and Caroline furnace lands in Greenup County, Kentucky, as conveyed by George Wurts and others to John Russell, January 1st, 1873, namely; Beginning at the South west corner of a tract of land containing 550 acres jointly owned by the Fulton Manufacturing and Coal Mining Company and the Norton Iron Works; thence on the line of said tract N 9 E 655 links to a stake in a ravine valley and on the South side of said ravine from which a cluster of three sycamores two of which are six and the other 8 inches diameter bears N 78 E 38 links and a white oak 6 inches diameter bears S 17 W 38 links; thence N 61 W up the ravine 490 links to a stake in the ravine; thence N 74 3/4 W. ascending a hill 960 links to a double black oak one prong of which is 8 and the other 9 inches diameter; thence S 53 1/2 W 447 links to a double black oak one prong of which is 8 inches and the other 9 inches diameter at the south side of the road; thence S 25 E 1900 links to a triple black oak one prong of which is 5 another 12 and another 16 inches diameter standing above same ore banks; thence S 7 E 888 links to a forked white oak 20 inches diameter on a high ridge; thence on the ridge S 70 1/3 E 276 links to a triple white oak one prong of which is 6 inches diameter; thence N 77 3/4 E 400 links to a point to a point 2 links North of a sassafras 4 inches diameter and a gum 4 inches diameter growing beside each other; thence N 72 E 441 links to a gum 6 inches diameter at the north side of a road; thence s 86 E 362 links to a cross on a large rock; thence S 42 E 330 links to a hickory 12 inches diameter at the east side of the road; thence S 15 E 452 links to a white oak; 7 inches diameter; thence S 32 3/4 E 336 links to a white oak 12 inches diameter on a knoll among ore diggings; thence S 73 E 452 links to a hickory 7 inches diameter; thence N 71 1/3 E 376 links to a white oak 8 inches diameter; thence N 72 E 526 links to a stake between a hickory 3 and a black walnut 4 inches diameter the south west corner of Norman Carter's land; thence on and with Norman Carter line North 700 links to a point in a ravine from which a black walnut stub 7 inches diameter bears N 20 E 25 links and a white oak 10 inches diameter bears S 80- 1/2 E 24 links; thence down the ravine N 29 W 203 links to a point between a sycamore 16 inches diameter and a white oak 3 inches diameter at the east side of the ravine; thence N 10 E 170 links to a white oak 5 inches diameter on the east side of said ravine; thence N 22 E 252 links to a sycamore 18 inches diameter at the East side of said ravine; thence N 30 2/3 E 394 links to a gum 3 inches diameter on the East side of said ravine and on the line of the 550 acre lot; thence on the line of said lot N 67 1/4 W 2750 links to the beginning and contains eighty-eight acres and forty-three hundredths of an acre (88.43). Bearings given from the present magnetic meridian, August, 1894.

Being the same real estate conveyed by KATHLEEN NIPPERT and THOMAS H. NIPPERT, her husband, to FRANK K. WARNOCK, by Deed dated April 14, 1978, and recorded in Deed Book 310, Page 665, Office of the Greenup County Clerk.

VII.

A complete full 100% ownership in and to the following described real estate lying in Greenup County, Kentucky, to-wit:

FIRST TRACT: Part of Steam and Caroline Furnace land on the waters of Taylors Run in Greenup County, State of Kentucky, Beginning at a stake on the summit of the hill on the west side of the county road, north west corner to Mrs. Clines land, thence on said Clines line South 80 ½° East 240 links to a stake from which a forked sycamore 14 inches diameter bears South 83° East 50 links. Thence North 67° East 530 links to a stake from which a white oak 7" diameter bears South 65° East 28 links. Thence North 79j° East 312 links to a stake from which a white oak 5" diameter bears South 221° East 8 links. Thence South 80° East 290 links to a white oak 8" diameter. Thence North 69J° East 242 links to a stake. Thence North 45° East 282 links to a stake from which a white oak 12" diameter bears South 56° East 19 links. Thence North 55'0 East 509 links to a black oak 9" diameter. Thence North 77-3/4° East 250 links to a double white oak each prong of which is 6" diameter. Thence South 471° East 260 links to a stake from which a white oak 10" diameter bears East 6 links. Thence South 28° East 522 links to a white oak 3" diameter. Thence South 56° East 262 links to a double black oak one prong 8 inches and the other 9 inches diameter at the South side of a road and northwest corner to Harrison W. Jacobs land. Thence with his line North 53}° East 447 links to a stake at the north side of the road. Thence North 50-3/4° East 351 links to a double black oak one prong 8 inches and the other 9 inches diameter. Thence leaving said Jacobs line and running North 25° West 530 links to a stake on top of a hill from which a 3 prong chestnut oak 12 inches diameter bears South 32° West 9 links and a black oak 8" diameter bears South 24° East 5 links. Thence North 47° East 500 links to a stake from which a black oak 15" diameter bears South 321 East 24 links and two black oaks one 5 and the other 7 inches diameter bears North 33° East 11 and 18 links respectively. Thence North 32 ½° West 1500 links to a white oak 6 inches diameter in Shaney gap. Thence South 65° West 650 links to a stake from which a black oak 14" diameter bears East 45 links a chestnut 8" diameter bears west 23 links and a black oak 15" diameter bears South 38 links. Thence South 48" West 780 links to a stake from which a white oak 8" diameter bears North 75° West 13 links and a double white oak one prong 2 and the other 3 inches diameter bears South 6° East 8 links. Thence South 76 ½° West 1840 links to a stake from which a white oak 8" diameter bears North 80° West 19 links, a white oak 6" diameter bears South 71° West 15 links and a maple 6" diameter bears South 64° West 15 links. Thence West 970 links to a stake on the West side of the county road from which a white oak 6" diameter bears South 82~° East 51 links. Thence South 5}° West 1201 links to the beginning and contains seventy acres (70). Bearings given from the magnetic meridian December 1st., 1894.

<u>SECOND TRACT</u>: Part of the Old Caroline Furnace tract of land on the waters of Chinns Branch in Greenup County, State of Kentucky. Beginning at a stone on the north side of a ravine and on the west line of a tract of land containing about 550 acres known as the Fulton Manufacturing & Coal Mining Company land, and which stone is 2125 links South 9-3/40 West from a stone at the north west corner of said tract. Thence up the ravine valley from the beginning point South 86° West 674 links to a white oak 8" diameter. Thence North 85}° west 757 links to a white oak 12} diameter near forks of ravine. Thence South 46}° West 535 links to a stake. Thence North 86° West 235 links to a hickory 2" diameter 6 links south of a black oak 16" diameter. Thence South 73}° West 459 links to a white oak 6" diameter on top of the hill in Shaney Gap, it being the North East corner to a former tact of land sold to said Garvey. Thence with the line of said Tract South 321° West 1500 links to a stake from which a black oak 15" diameter bears South 32}° East 24 links and two black oaks one 5" and the other 7" diameter bears North 33° East and 11 and 16 links respectively. Thence South 47° West 500 links to a stake from which a 3 pronged chestnut oak 12" diameter bears South 32° West 9 links and a black oak 8" diameter bears South 24° East 5 links. Thence descending the hill South 25° East 530 links to a double black oak one prong 8" and the other 9" diameter corner to Harrison Jacobs land. thence on said Jacob line South 74-3/4° East 960 links to a stake in a ravine. Thence south 61° East 490 links to a stake on line of said 550 acres herein before mentioned at the North east corner of said Jacobs land from which a cluster of 3 sycamores two of which are 6" and the other 8" diameter, bears North 78° East 38 links and a white oak 6" diameter bears South 17° West 38 links. Thence on the line of said 550 acres north 9-3/4° East 3100 links to the beginning and contains Forty nine acres and forty four hundredths of an acre (49.44). Bearings given from the Magnetic Meridian May, 1897.

EXCEPTION ONE: Excepting therefrom parcels one and two as above described approximately twenty (20) acres more particularly described by Deed dated April 22, 1942, and recorded in Deed Book 95 at page 17, Greenup County, Kentucky, County Clerk's Office wherein Margaret Lancaster and Hubert Lancaster conveyed to W. R. Clarke.

EXCEPTION TWO: Excepting therefrom approximately five acres of land in the South-east corner of the farm described in parcels one and two which was previously conveyed by Benjamin E. Garvey and Mary E. Garvey, husband and wife, to William Clarke and Stella L. Clarke, husband and wife.

The above described FIRST TRACT and SECOND TRACT being the same real estate described and conveyed in the Deed from BETTY L. WADDELL, Widow, to FRANK K. WARNOCK, by Deed dated February 6, 1969, and recorded in Deed Book 231, Page 324, Office of the Greenup County Clerk.

TRACTS I thru VII above being the same real estate and interest in real estate conveyed to Grantors as Trustees in Deed Book 429, Page 199 and Deed Book 441, Page 74, in the Office of Greenup County Court Clerk.

IT IS UNDERSTOOD, AGREED AND COVENANTED by and between the parties hereto, and it is the intention of the parties hereto that full and complete title and ownership, and interest in and to the above described real estate or interest in real estate is conveyed free of Trust and individually to Frank H. Warnock (1/4), Matthew J. Warnock (1/4), Anna M. Neal (f/k/a Anna Michelle Warnock) (1/4), and Carolyn P. Warnock (1/4), parties of the second part.

This is a family transfer with no monetary consideration for the conveyance herein. The Fair Market Value of the property being conveyed is <u>$151,823.00</u>.

TO HAVE AND TO HOLD the above interest and ownership in and to said real estate with all the rights, privileges and appurtenances thereunto belonging, or in anywise appertaining, unto the parties of the second part, their heirs and assigns, forever, with covenants of General Warranty.

IN WITNESS WHEREOF, the parties of the first part have hereunto subscribed their names this ______ day of ________________, 2012.

Frank H. Warnock	Matthew J. Warnock
FRANK H. WARNOCK Trustee for Frank H. Warnock, Matthew J. Warnock; Anna Michelle Warnock and Carolyn P. Warnock	MATTHEW J. WARNOCK Trustee for Frank H. Warnock, Matthew J. Warnock; Anna Michelle Warnock and Carolyn P. Warnock

STATE OF KENTUCKY
COUNTY OF GREENUP

The foregoing Deed was acknowledged before me this 23rd day of July, 2012, by FRANK H. WARNOCK and MATTHEW J. WARNOCK, Trustees for Frank H. Warnock, Matthew J. Wanrock, Anna Michelle Warnock, and Carolyn P. Warnock.

My Commission expires 12-29-15 # 457270.

Beverly Parish
NOTARY PUBLIC
GREENUP COUNTY, KENTUCKY

CONSIDERATION CERTIFICATE

We, the undersigned, do hereby certify, pursuant to KRS Chapter 382, that this is a family transfer with no monetary consideration for the conveyance herein. The Fair Market Value of the real estate being conveyed is stated herein. We further certify our understanding that falsification of the stated consideration of sale price of the property is a Class D felony, subject to one to five years imprisonment and fines up to $10,000.00.

Frank H. Warnock	Matthew J. Warnock
FRANK H. WARNOCK, Trustee for Frank H. Warnock, Matthew J. Warnock Anna Michelle Warnock and Carolyn P. Warnock, Grantor	MATTHEW J. WARNOCK, Trustee for Frank H. Warnock, Matthew J. Warnock, Anna Michelle Warnock and Carolyn P. Warnock, Grantor

Frank H. Warnock
FRANK H. WARNOCK, Grantee

Matthew J. Warnock
MATTHEW J. WARNOCK, Grantee

Anna M. Neal
ANNA M. NEAL, Grantee

Carolyn P. Warnock
CAROLYN P. WARNOCK, Grantee

STATE OF KENTUCKY
COUNTY OF GREENUP

The foregoing Certificate was Acknowledged and Sworn to before me this 23rd day of July, 2012, by FRANK H. WARNOCK and MATTHEW J. WARNOCK, Trustees for Frank H. Warnock; Matthew J. Warnock; Anna Michelle Warnock and Carolyn P. Warnock, Grantors.

My Commission expires 12-29-15 #457270.

Beverly Parish
NOTARY PUBLIC
GREENUP COUNTY, KENTUCKY

STATE OF KENTUCKY
COUNTY OF GREENUP

The foregoing Certificate was Acknowledged and Sworn to before me this 23rd day of July, 2012, by FRANK H. WARNOCK, Grantee.

My Commission expires 12-29-15 #457270.

Beverly Parish
NOTARY PUBLIC
GREENUP COUNTY, KENTUCKY

STATE OF KENTUCKY
COUNTY OF GREENUP

The foregoing Certificate was Acknowledged and Sworn to before me this 23rd day of July, 2012, by MATTHEW J. WARNOCK, Grantee.

My Commission expires 12-29-15 #457270.

Beverly Parish
NOTARY PUBLIC
GREENUP COUNTY, KENTUCKY

STATE OF TENNESSEE
COUNTY OF Davidson

The foregoing Certificate was Acknowledged and Sworn to before me this 29th day of Aug, 2012, by ANNA M. NEAL, Grantee.

My Commission expires 1-7-2013.

CHRISTI DYER STATE OF TENNESSEE NOTARY PUBLIC COUNTY OF DAVIDSON
MY COMMISSION EXPIRES: JANUARY 7, 2013

Christi Dyer
NOTARY PUBLIC
Davidson COUNTY, TENNESSEE

STATE OF KENTUCKY
COUNTY OF GREENUP

The foregoing Certificate was Acknowledged and Sworn to before me this 23Rd day of July, 2012, by CAROLYN P. WARNOCK, Grantee.

My Commission expires 12-29-15 #457270.

Beverly Parish
NOTARY PUBLIC
GREENUP COUNTY, KENTUCKY

The current year tax bill is to be mailed:
c/o Varney Bills - no charge.

THIS ABOVE BLANK SHOULD BE FILLED IN BY THE GRANTEE OR HIS REPRESENTATIVE. THE DEED PREPARER ASSUMES NO RESPONSIBILITY FOR THE CORRECTNESS OF THIS INFORMATION.

This DEED prepared by:
FRANK H. WARNOCK
Warnock & Warnock
P. O. Box 617
Greenup, KY 41144

Frank H. Wk

DOCUMENT NO: 431594
RECORDED ON: SEPTEMBER 18,2012 02:34:00P
TOTAL FEES: $38.00
COUNTY CLERK: PAT HIEMENON
COUNTY: GREENUP COUNTY
DEPUTY CLERK: TERRI GABBARD
BOOK D577 PAGES 73 - 82

KENTUCKY STATE BOARD ON ELECTRIC GENERATION AND TRANSMISSION SITING

IN RE: **Application of**
SunCoke Energy South Shore, LLC.
CASE NO. 2014-00162

AFFIDAVIT RE CERTIFICATIONS REQUIRED BY KRS 278.706(2)(d)

Comes the Affiant, George L. Seay, Jr., and after first being duly sworn upon his oath states as follows:

1. That my name is George L. Seay, Jr.

2. That I am an attorney at Wyatt, Tarrant & Combs, LLP and counsel to the applicant herein.

3. That I am over the age of twenty one years and am otherwise qualified to execute the Certification.

4. That I have conducted an inquiry into the facts contained in this Affidavit and believe them to be true to the best of my knowledge.

5. Upon researching the local ordinances of Greenup County and confirming with the Local Authorities, I found that there are no local planning and zoning ordinances, and no local setback requirements which are applicable to the proposed SunCoke Energy South Shore LLC project.

6. That research also determined that there is a Noise Ordinance for the unincorporated boundaries of Greenup County (see the attached copy of that Ordinance) but that ordinance is not applicable to the proposed SunCoke Energy South Shore LLC project since the ordinance only applies to homes or residences.

7. Therefore, I hereby certify that there are no planning and zoning requirements, local setback requirements, and no regulations or ordinances concerning noise control for Greenup County, Kentucky, which would apply to the project for which this application is submitted.

Further, Affiant sayeth naught, this the 8th day of Dec, 2014.

George L. Seay, Jr.
Wyatt, Tarrant & Combs, LLP
250 West Main Street, Suite 1600
Lexington, KY 40507-1746

COMMONWEALTH OF KENTUCKY)
) :S
COUNTY OF FAYETTE)

The foregoing instrument was subscribed and sworn to before me this 8th day of December, 2014 by George L. Seay, Jr.

My commission expires 2/20/15.

NOTARY PUBLIC

PREPARED BY:

George L. Seay, Jr.
WYATT, TARRANT & COMBS, LLP
250 West Main Street, Suite 1600
Lexington, KY 40507
(859) 288-7448

61247081.2

COMMONWEALTH OF KENTUCKY
GREENUP COUNTY FISCAL COURT

ORDINANCE NO. 01-2013

AN ORDINANCE RELATING TO THE ESTABLISHMENT OF STATUTORY CONTROLS TO RESTRICT AND REDUCE THE NUISANCE CAUSED BY GENERAL NEIGHBORHOOD NOISE

WHEREAS, the Greenup County Fiscal Court desires to establish statutory controls to restrict and reduce the emission of noise between the hours of 11:00 PM and 7:00 AM which is audible in the interior of a dwelling one hundred (100) feet from the property line of the property on which the source of the noise is located for a period exceeding fifteen (15) minutes cumulatively.

WHEREAS, the Kentucky Revised Statutes grant to the Fiscal Court of Greenup County, Kentucky, the power and authority to enact ordinances in the interest of its citizens.

WHEREAS, this Ordinance shall apply to any home or residence of any kind lying within the unincorporated boundaries of Greenup County.

WHEREAS, the following noises shall be exempt:

(a) Noises originating from any safety signals, warning devices and emergency relief valves
(b) Noises resulting from any authorized emergency or law enforcement vehicle or training facilities
(c) Noises emanating from festivals or other periodic activities and celebrations
(d) Noises originating from the production of crops or livestock
(e) Noises originating from a permitted industrial or commercial activity

WHEREAS, citations may be issued by any sworn police officer for the enforcement of the provisions of this Ordinance.

WHEREAS, should any part of this Ordinance be held invalid by a court of competent jurisdiction, the remaining parts shall be severable and shall continue to be in full force and effect. This Ordinance shall be in full force and effect immediately upon adoption and after being published pursuant to law.

NOW, THEREFORE, BE IT ORDAINED by the Greenup County Fiscal Court that it does hereby approve establishing statutory controls to restrict and reduce the emission of noise between the hours of 11:00 PM and 7:00 AM.

GIVEN SECOND READING, APPROVED, ADOPTED AND PASSED at the regular meeting of the Fiscal Court of Greenup County, Kentucky, held on this 9th day of July, 2013.

Robert W. Carpenter
Greenup County Judge/Executive

Attest:

R. Diane Carpenter

R. Diane Carpenter
Fiscal Court Clerk

First Reading: June 11, 2013
Second Reading: July 9, 2013

"Road, River & Rail"

Robert W. Carpenter, *Greenup County Judge Executive*

301 Main Street • Room 102 • Courthouse • Greenup, Kentucky 41144
(606) 473-6440 • (606) 473-6864 • FAX (606) 473-9878

November 12, 2014

Mr. Douglas Jeavons
Managing Director
BBC Research Consulting
1999 Broadway
Suite 2200
Denver, CO 80202-9750

Dear Mr. Jeavons:

The Greenup County Road Department will build a temporary road through the property of Kathy Reed to by-pass Graff Brothers lumber yard, re-entering at the second gate to CR 1044 Johnson Lane. This will allow Graff Brothers to maintain their business without interruption by construction traffic.

Once use of the temporary road for construction purposes begins, the Greenup County Road Department will rebuild the existing CR 1044 Johnson Lane road, clean the ditches and place either crusher run or DGA the depth necessary for construction of the road on CR 1044 Johnson Lane.

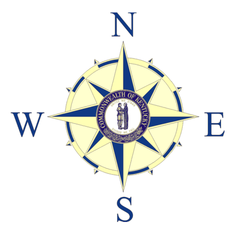
After completion of the SunCoke Energy Plant facilities, the Fiscal Court will re-construct and repave CR 1044 Johnson Lane to the SunCoke properties.

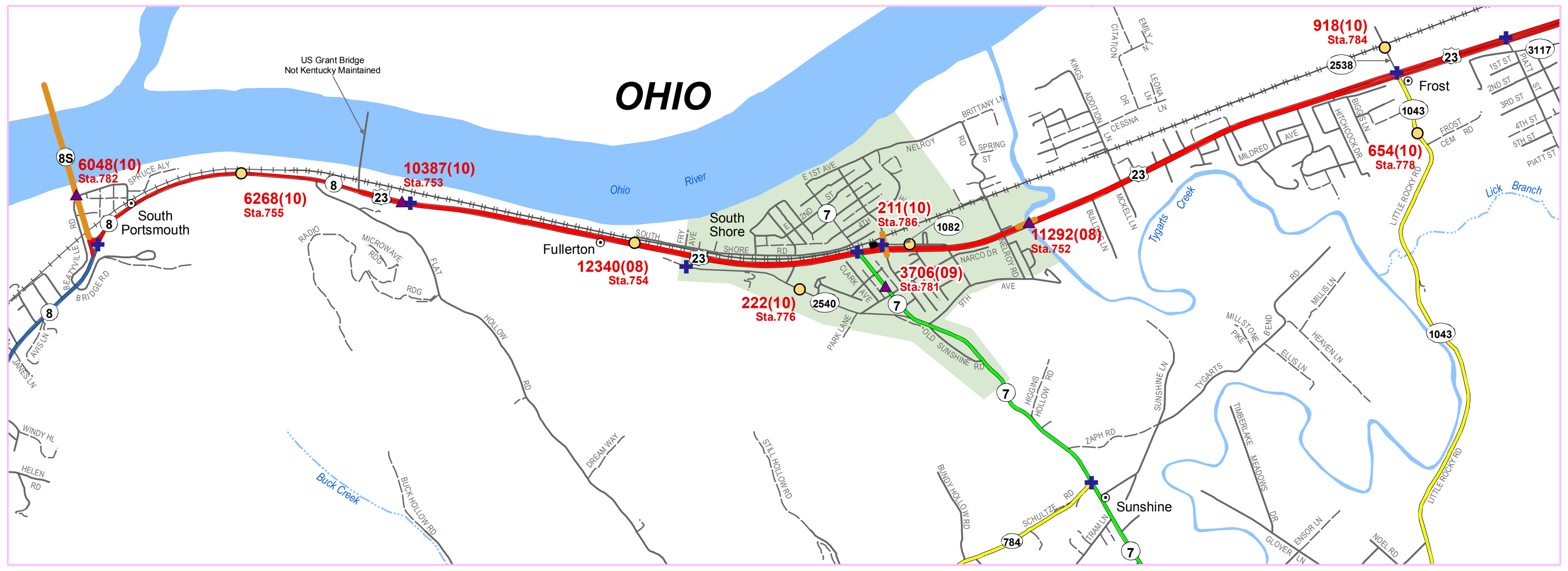
Please get in touch with my office with any questions you may have.

Sincerely,

Robert W. Carpenter
County Judge/Executive

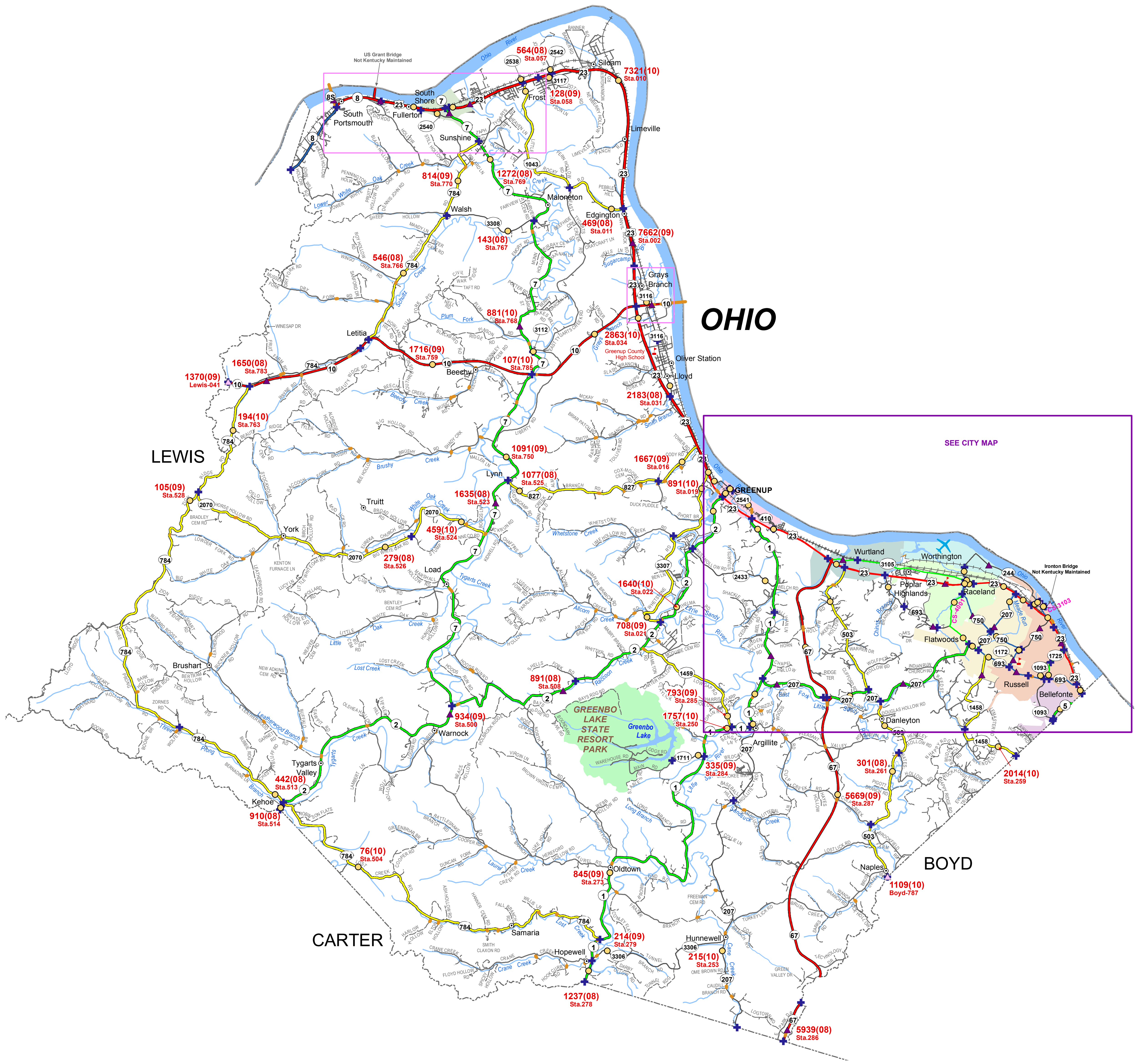
Cc: Mr. David Schwake ✓

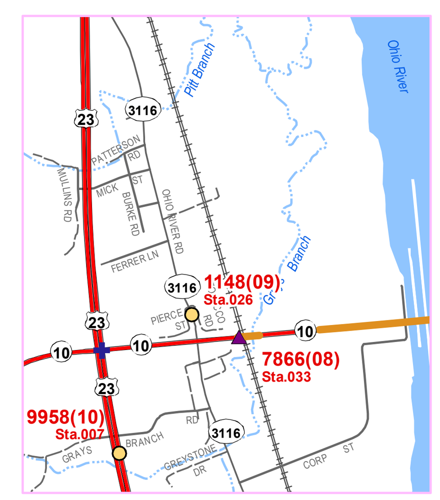




0.5 0.25 0 0.5 1 1.5 Miles

SOUTH SHORE





0.5 0.25 0 0.5 Miles

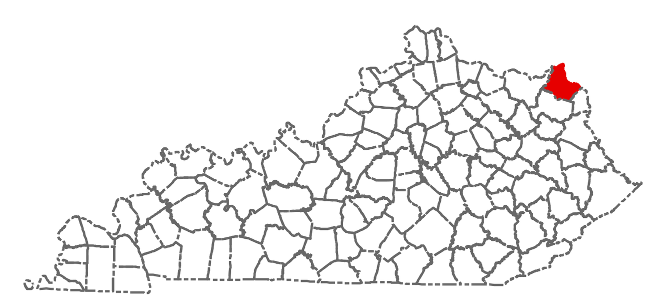
GRAYS BRANCH

Count Stations

- ATR
- Full Coverage
- Classification
- Adjacent
- Termini

Functional Classification

- Rural Interstate
- Rural Principal Arterial
- Rural Minor Arterial
- Rural Major Collector
- Rural Minor Collector
- Urban Interstate
- Urban Freeways & Expressways
- Urban Principal Arterial
- Urban Minor Arterial Street
- Urban Collector Street
- Rural & Urban Local
- CS-0000 Functionally Classified Road No.
- Bridge
- Railroad
- Stream
- City/Town
- Airport
- Federal Aid Urbanized Area 2000
- Incorporated Area
- Lake
- State Park
- National Park or Recreation Area
- Defense Facility
- Wildlife Area
- Geological Area
- State, National, or Private Forest



The Kentucky Transportation Cabinet does not warrant that the information contained on this map is accurate or complete. The Kentucky Transportation Cabinet states that all attempts are made to insure the correctness of road network portrayal and it is based on the best available information at a given time but disclaims any and all representations and/or warranties made with respect to this map by any contributing source as to its contents, whether expressed, implied, or statutory, including, but not limited to, warranties of title, merchantability, and fitness for a particular purpose.

KENTUCKY TRANSPORTATION CABINET
Division of Planning
Kentucky UNBRIDLED SPIRIT

Traffic Station Counts
GREENUP COUNTY

2 1 0 2 4 6 Miles

Last map revision: FEBRUARY 2011 D.O.

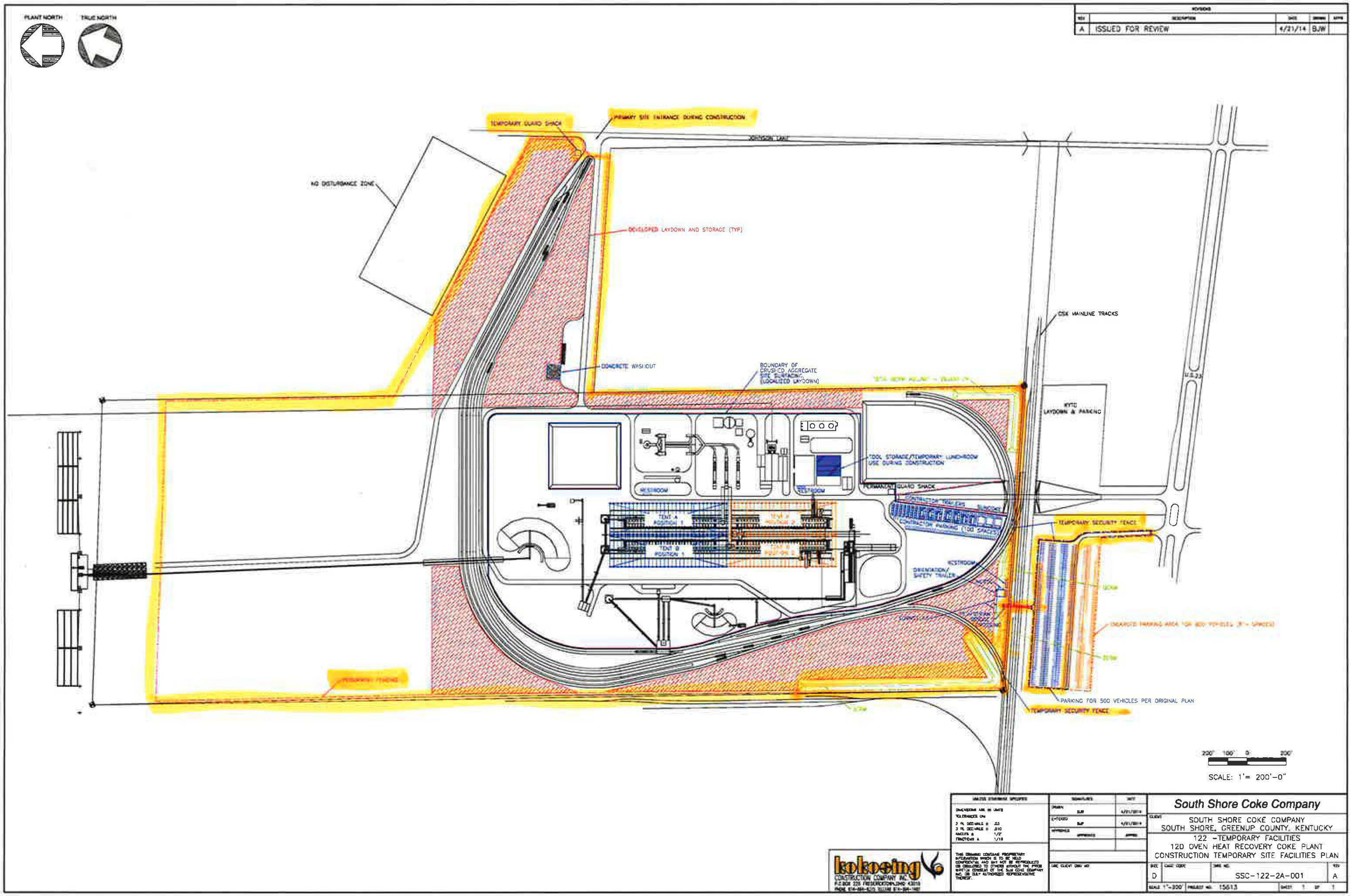
Latest traffic count date for each station is indicated on the map in parentheses after the actual traffic count. For the most current traffic count information, please refer to the Counts Database Program (CTS) found on the Division of Planning website.

www.planning.kytc.ky.gov

Station locations are plotted at segment midpoints where actual milepoints have not been verified in the field.

Kentucky State Plane Coordinate System (NAD-83)

Traffic Station Counts GREENUP COUNTY KENTUCKY 045


PLANT NORTH
TRUE NORTH
ISSUED FOR REVIEW
4/21/14
BJW
TEMPORARY GUARD SHACK
PRIMARY SITE ENTRANCE DURING CONSTRUCTION
JOHNSON LANE
NO DISTURBANCE ZONE
DEVELOPED LAYDOWN AND STORAGE (TYP)
CSX MAINLINE TRACKS
CONCRETE WASHOUT
BOUNDARY OF CRUSHED AGGREGATE SITE SURFACING (LOCALIZED LAYDOWN)
U.S.23
KYTC LAYDOWN & PARKING
RESTROOM
TOOL STORAGE/TEMPORARY LUNCHROOM USE DURING CONSTRUCTION
PERMANENT GUARD SHACK
TENT A POSITION 1
TENT B POSITION 1
CONTRACTOR TRAILERS
CONTRACTOR PARKING (100 SPACES)
TEMPORARY SECURITY FENCE
ORIENTATION/ SAFETY TRAILER
TEMPORARY FENCING
PARKING FOR 500 VEHICLES PER ORIGINAL PLAN
TEMPORARY SECURITY FENCE
200' 100' 0 200'
SCALE: 1'= 200'-0"
South Shore Coke Company
SOUTH SHORE COKE COMPANY
SOUTH SHORE, GREENUP COUNTY, KENTUCKY
122 -TEMPORARY FACILITIES
120 OVEN HEAT RECOVERY COKE PLANT
CONSTRUCTION TEMPORARY SITE FACILITIES PLAN
D
SSC-122-2A-001
A
15613
kokosing
CONSTRUCTION COMPANY INC.

Industrial Hygiene Division

Noise Survey Assessment

Client: SunCoke Energy – South Shore, KY
Date of Assessment: 07 December 2014
Location: South Shore Operations
IH Professional: Matt Boggs

MEA
Industrial Hygiene Division

Client: SunCoke Energy – South Shore, KY
Date of Assessment: 07 December 2014
Location: South Shore Operations
IH Professional: Matt Boggs

Introduction

On 07 December 2014 McCulley, Eastham & Associates, Inc. performed a noise level baseline assessment for SunCoke Energy South Shore Operations. The following information summarizes the findings for the locations given.

Report Summary

Two different monitoring points were given by the client indicating the points to be sampled. Those locations are detailed in Appendix A of this document. Each location was monitored for a period of thirteen hours utilizing a Quest Technologies SoundPro SLM hand held sound level meter. The calibration documentation for these devices can be found in Appendix E of this document. The raw data from those two locations can be found in Appendix C and D of this document.

While the two samples were being conducted, local traffic flow and patterns were noted as well as any abnormal noise sources that may have impacted the data collected. These notes can be found in Appendix B of this document.

These samples were taken in a residential area near US Highway 23 and the Sand Hill Church of Christ.

The traffic flows taken into consideration, the time weighted average (TWA) for Monitoring Point A was 60.5db. The TWA for Monitoring Point B was 59.7db. The average for the area based on these two figures is **60.1db**. The highest documented reading was 98.5db and that was from Monitoring Point A at 08:30. This was due to visiting pedestrian slamming a car door near the unit. Traffic on route 3117 was standard pedestrian vehicles for the duration of sampling. The high / low ranges was between 88.0db and 37.2db for the area. Averages went up to an average of 60.1db during higher traffic flows and 48.6db during lower traffic flows.

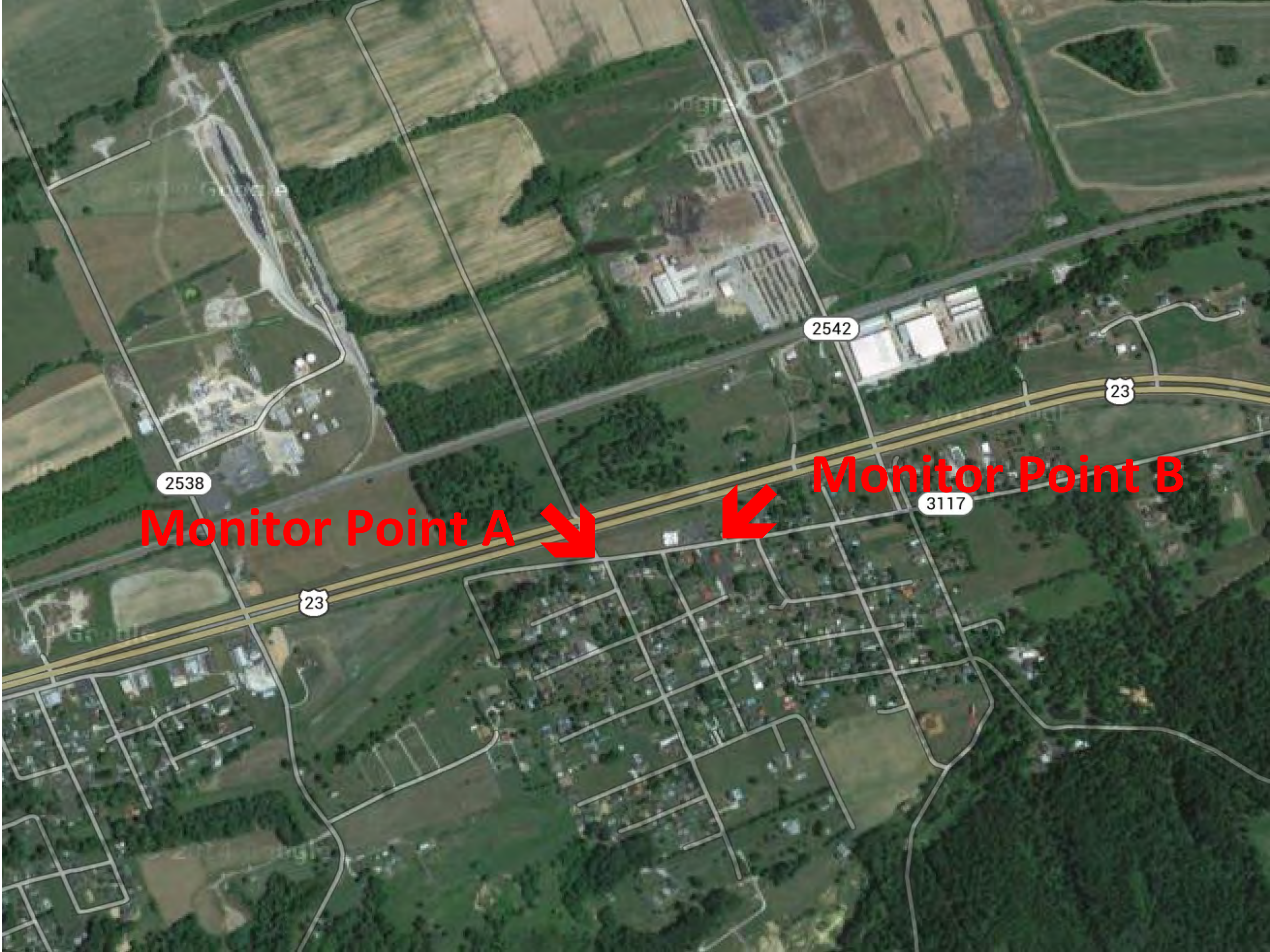
Conclusion

All factors were observed in an effort to establish baseline background noise levels for the given area. Any sources of noise were taken into consideration and noted accordingly. The above averages and levels should serve as a baseline indicator for the current noise levels of that area.

Industrial Hygiene Division

APPENDIX A

Monitoring Point A Location



2542
23
Monitor Point B
3117
2538
Monitor Point A
23

Monitor Point B
Monitor Point A
23
23
23
3117

MEA

Industrial Hygiene Division

APPENDIX B

Monitoring Traffic Notes

Time Range:	Monitoring Point A	Monitoring Point B	Notes:
0645 - 0730	6	5	Standard Personal Vehicle Traffic
0730 - 0800	3	1	Standard Personal Vehicle Traffic
0800 - 0830	4	4	Standard Personal Vehicle (PV) Traffic, One Looker Slammed Car Door
0830 - 0900	12	8	Standard Personal Vehicle Traffic
0900 - 0930	23	17	Truck Started Nearby (09:14), Standard PV Traffic, Start of Heavy Traffic Flow
0930 - 1000	27	16	Standard PV Traffic, Still Heavy Traffic Flow
1000 - 1030	30	17	Standard PV Traffic, End of Heavy Traffic Flow
1030 - 1100	15	10	Standard PV Traffic, Normal Traffic Flow
1100 - 1130	19	13	Standard PV Traffic, Normal Traffic Flow
1130 - 1200	21	19	Standard PV Traffic, Slightly Heavier Traffic, Church Released at 11:36
1200 - 1230	17	15	Standard PV Traffic, Normal Traffic Flow
1230 - 1300	18	14	Standard PV Traffic, Normal Traffic Flow
1300 - 1330	18	15	Standard PV Traffic, Normal Traffic Flow
1330 - 1400	26	18	Standard PV Traffic, Normal Traffic Flow
1400 - 1430	22	19	Standard PV Traffic, Normal Traffic Flow
1430 - 1500	22	14	Standard PV Traffic, Normal Traffic Flow
1500 - 1530	20	15	Standard PV Traffic, Normal Traffic Flow
1530 - 1600	16	12	Standard PV Traffic, Normal Traffic Flow
1600 - 1630	18	15	Standard PV Traffic, Normal Traffic Flow
1630 - 1700	19	17	Standard PV Traffic, Normal Traffic Flow
1700 - 1730	17	15	Standard PV Traffic, Normal Traffic Flow
1730 - 1800	18	14	Standard PV Traffic, Normal Traffic Flow
1800 - 1830	19	18	Standard PV Traffic, Normal Traffic Flow
1830 - 1900	24	21	Heavy Traffic Flow, Church Service at 18:32, Standard PV Traffic
1900 - 1930	21	19	Standard PV Traffic, Still Heavy Traffic Flow
1930 - 2000	24	23	Standard PV Traffic, Slightly Heavier Traffic, Church Released at 19:32

Monitoring Point A and B columns indicate the number of Personal Vehicles that passed in close proximity during the duration of the monitoring.

Industrial Hygiene Division

APPENDIX C

Monitoring Point A Data

Session Report

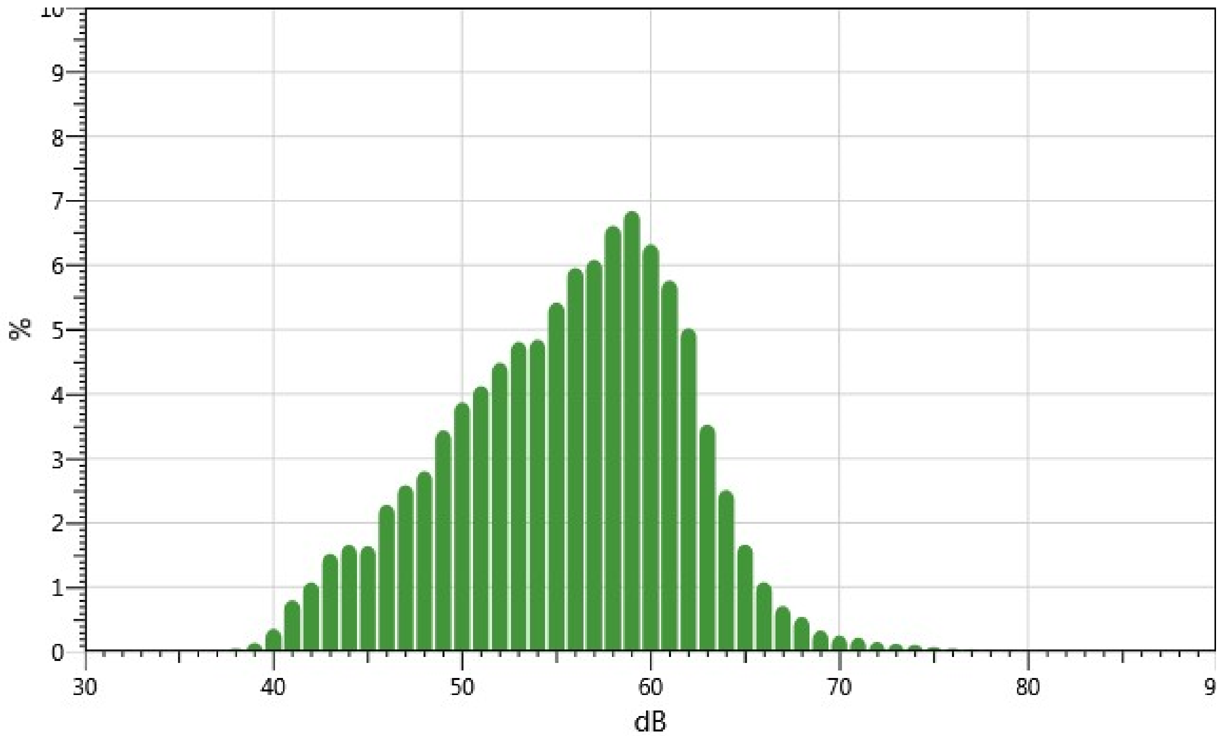
12/8/2014

Information Panel

Name	S001_BJK020008_07122014_210456
Start Time	12/7/2014 6:45:56 AM
Stop Time	12/7/2014 8:09:58 PM
Device Name	BJK020008
Model Type	SoundPro DL
Device Firmware Rev	R.13H
Comments	

Statistics Chart

S001_BJK020008_07122014_210456: Statistics Chart



Statistics Table

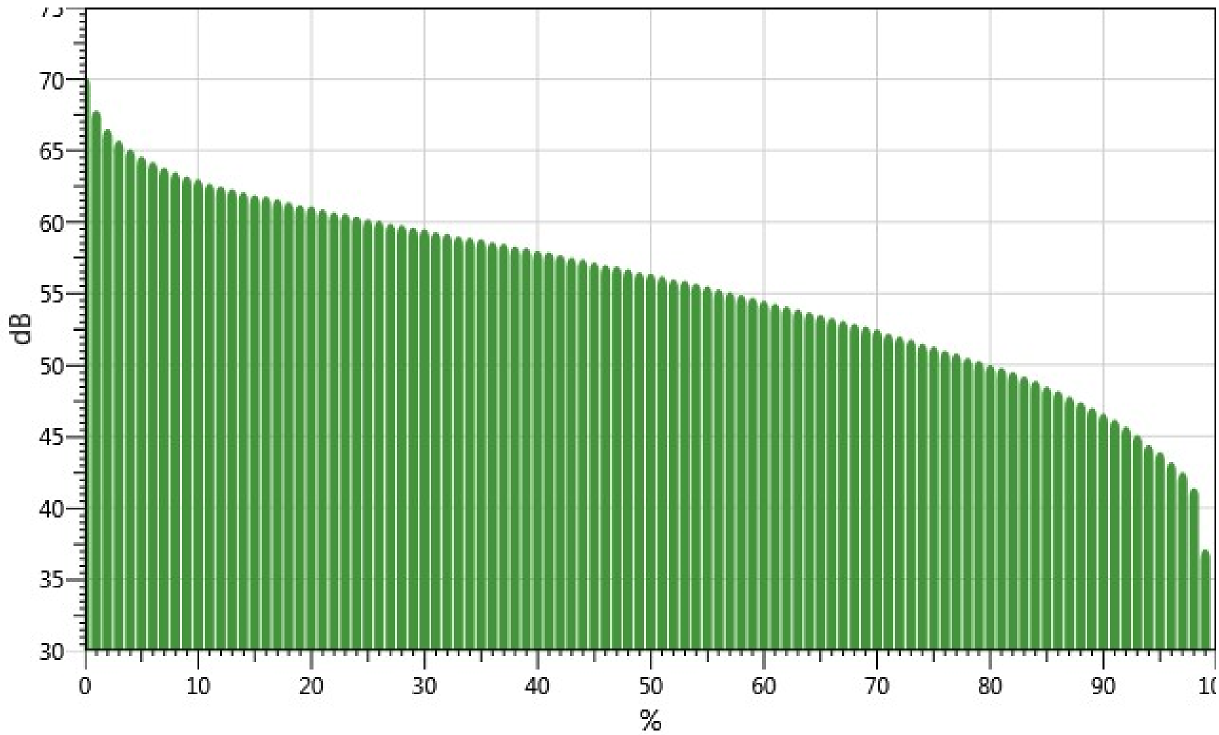
dB:	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	%
30:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

34:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
37:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
38:	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.05
39:	0.01	0.02	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.14
40:	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.04	0.06	0.07	0.36
41:	0.07	0.08	0.08	0.04	0.08	0.09	0.09	0.09	0.08	0.09	0.80
42:	0.10	0.10	0.10	0.10	0.10	0.10	0.12	0.12	0.11	0.12	1.08
43:	0.13	0.14	0.15	0.15	0.14	0.15	0.15	0.17	0.17	0.18	1.52
44:	0.20	0.20	0.20	0.12	0.17	0.17	0.15	0.15	0.14	0.15	1.66
45:	0.15	0.14	0.15	0.16	0.16	0.17	0.17	0.18	0.18	0.17	1.64
46:	0.19	0.18	0.19	0.20	0.21	0.24	0.26	0.26	0.26	0.28	2.28
47:	0.27	0.26	0.28	0.18	0.25	0.26	0.27	0.27	0.27	0.26	2.59
48:	0.27	0.29	0.28	0.26	0.25	0.26	0.27	0.31	0.31	0.31	2.80
49:	0.31	0.34	0.34	0.33	0.34	0.34	0.34	0.35	0.36	0.39	3.44
50:	0.41	0.40	0.42	0.29	0.38	0.38	0.38	0.39	0.39	0.41	3.87
51:	0.40	0.38	0.42	0.43	0.41	0.44	0.43	0.41	0.40	0.41	4.13
52:	0.39	0.41	0.43	0.45	0.45	0.46	0.46	0.47	0.48	0.48	4.49
53:	0.51	0.53	0.54	0.36	0.47	0.48	0.50	0.48	0.47	0.48	4.81
54:	0.48	0.48	0.48	0.48	0.48	0.49	0.50	0.48	0.47	0.50	4.85
55:	0.51	0.52	0.51	0.50	0.52	0.53	0.56	0.57	0.59	0.60	5.42
56:	0.61	0.63	0.66	0.46	0.62	0.62	0.59	0.59	0.58	0.60	5.96
57:	0.60	0.59	0.59	0.59	0.60	0.62	0.63	0.62	0.62	0.62	6.08
58:	0.61	0.62	0.63	0.65	0.65	0.65	0.68	0.69	0.70	0.73	6.62
59:	0.74	0.76	0.75	0.61	0.63	0.69	0.67	0.67	0.66	0.65	6.84
60:	0.65	0.64	0.66	0.65	0.63	0.63	0.63	0.63	0.62	0.59	6.33
61:	0.58	0.59	0.59	0.61	0.58	0.57	0.57	0.56	0.55	0.56	5.76
62:	0.56	0.57	0.60	0.52	0.42	0.51	0.49	0.47	0.45	0.43	5.02
63:	0.43	0.40	0.37	0.36	0.35	0.35	0.34	0.31	0.31	0.30	3.53
64:	0.29	0.27	0.28	0.26	0.26	0.24	0.24	0.24	0.22	0.21	2.51
65:	0.20	0.21	0.21	0.20	0.12	0.16	0.15	0.15	0.13	0.13	1.67
66:	0.12	0.12	0.12	0.12	0.11	0.10	0.10	0.11	0.10	0.10	1.08
67:	0.08	0.08	0.07	0.08	0.07	0.07	0.07	0.06	0.06	0.06	0.71
68:	0.06	0.06	0.06	0.07	0.04	0.06	0.05	0.05	0.05	0.04	0.54
69:	0.04	0.04	0.04	0.03	0.04	0.03	0.03	0.03	0.03	0.02	0.33
70:	0.03	0.02	0.03	0.02	0.03	0.03	0.03	0.02	0.02	0.02	0.25

71:	0.03	0.03	0.02	0.03	0.01	0.02	0.02	0.02	0.02	0.02	0.22
72:	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.15
73:	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.12
74:	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.10
75:	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.07
76:	0.01	0.01	0.01	0.01	0.00	0.00	0.01	0.00	0.01	0.00	0.05
77:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04
78:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
79:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
80:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
81:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
82:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
83:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
84:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
85:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
86:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
87:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
88:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
89:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
90:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Exceedance Chart

S001_BJK020008_07122014_210456: Exceedance Chart

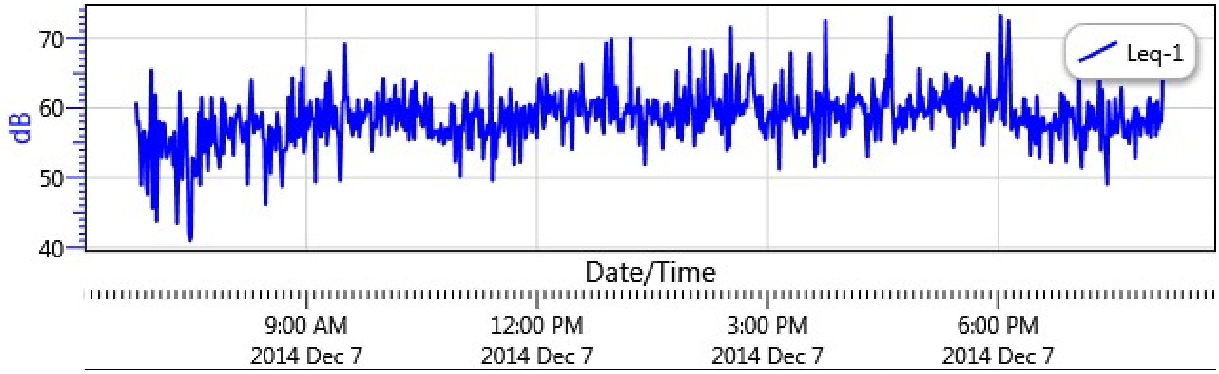


Exceedance Table

.	0%	1%	2%	3%	4%	5%	6%	%7	%8	%9
0%:		70.2	67.8	66.5	65.7	65.1	64.6	64.2	63.8	63.5
10%:	63.2	63.0	62.7	62.5	62.3	62.1	61.9	61.8	61.6	61.4
20%:	61.2	61.1	60.9	60.7	60.6	60.4	60.2	60.1	59.9	59.8
30%:	59.6	59.5	59.3	59.2	59.0	58.9	58.8	58.6	58.5	58.3
40%:	58.2	58.0	57.9	57.7	57.5	57.4	57.2	57.0	56.9	56.7
50%:	56.5	56.4	56.2	56.0	55.9	55.7	55.5	55.3	55.1	54.9
60%:	54.7	54.5	54.3	54.1	53.9	53.7	53.5	53.3	53.1	52.9
70%:	52.7	52.5	52.2	52.0	51.8	51.5	51.3	51.0	50.8	50.5
80%:	50.3	50.0	49.8	49.5	49.2	48.9	48.5	48.2	47.8	47.4
90%:	47.0	46.6	46.2	45.7	45.1	44.4	43.9	43.2	42.5	41.4
100%:	37.1									

Logged Data Chart

S001_BJK020008_07122014_210456: Logged Data Chart



Summary Data Panel

Description	Meter	Value	Description	Meter	Value
Leq	1	--			
Exchange Rate	1	3 dB	Weighting	1	A
Response	1	SLOW	Bandwidth	1	OFF
Exchange Rate	2	3 dB	Weighting	2	A
Response	2	SLOW			

Industrial Hygiene Division

APPENDIX D

Monitoring Point B Data

Session Report

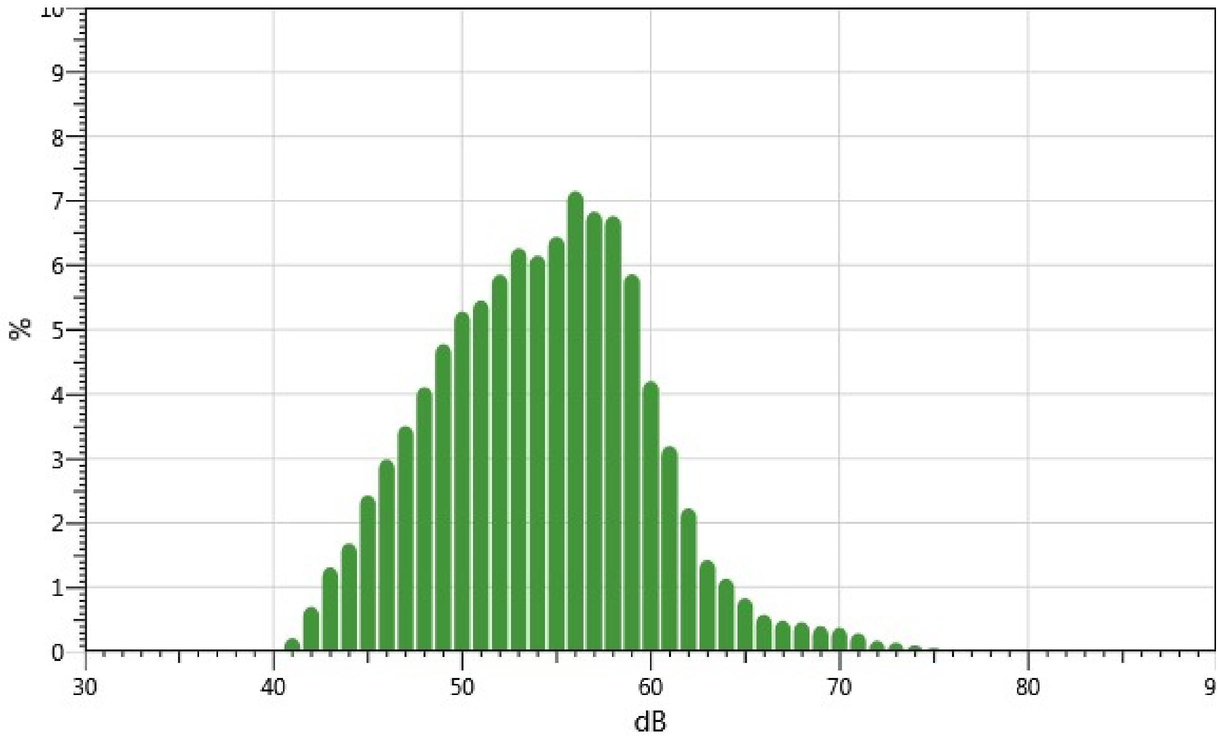
12/8/2014

Information Panel

Name	S001_BJK020008_07122014_210841
Start Time	12/7/2014 6:55:04 AM
Stop Time	12/7/2014 8:13:14 PM
Device Name	BJI020017
Model Type	SoundPro DL
Device Firmware Rev	R.13H
Comments	

Statistics Chart

S001_BJK020008_07122014_210841: Statistics Chart



Statistics Table

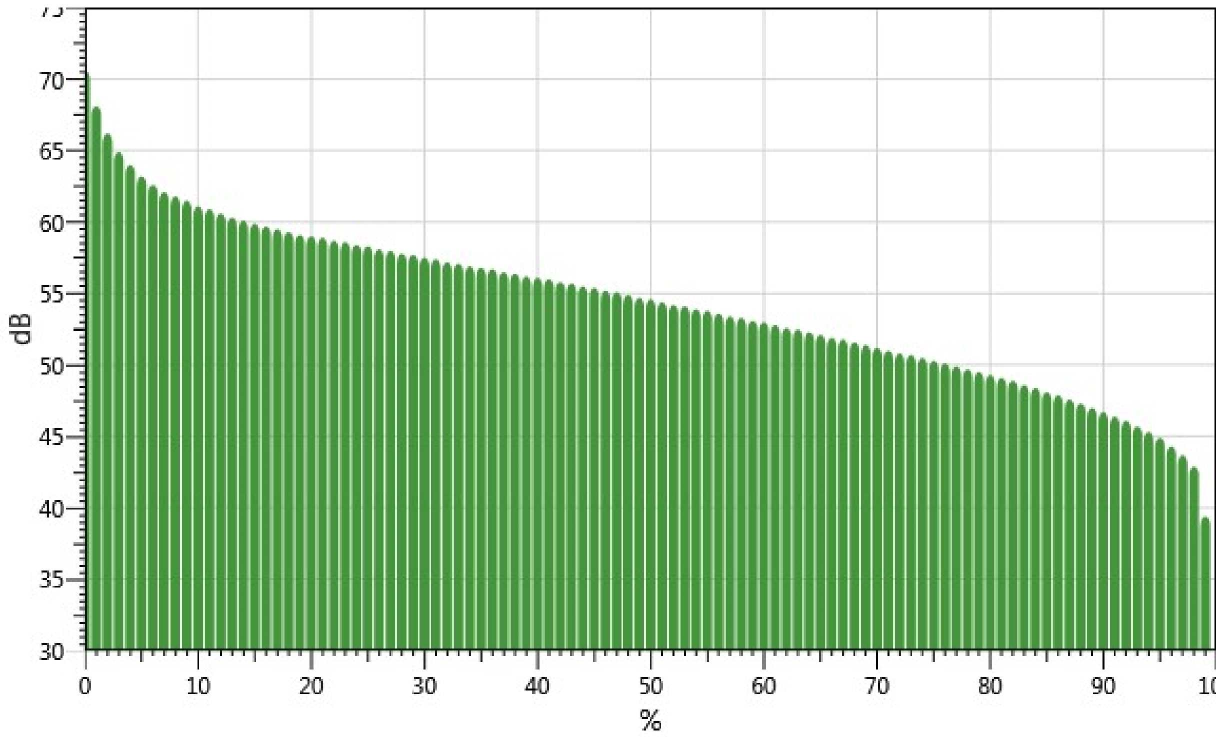
dB:	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	%
30:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

34:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
36:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
37:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
38:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
39:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
41:	0.00	0.01	0.01	0.01	0.02	0.03	0.03	0.03	0.04	0.05	0.21
42:	0.06	0.05	0.06	0.06	0.06	0.06	0.07	0.08	0.09	0.10	0.70
43:	0.11	0.10	0.11	0.13	0.13	0.15	0.15	0.14	0.14	0.16	1.31
44:	0.16	0.16	0.18	0.12	0.17	0.15	0.17	0.18	0.20	0.21	1.69
45:	0.21	0.22	0.22	0.24	0.25	0.23	0.25	0.26	0.25	0.28	2.43
46:	0.27	0.27	0.26	0.31	0.31	0.30	0.33	0.30	0.31	0.32	2.99
47:	0.35	0.35	0.40	0.26	0.34	0.35	0.35	0.35	0.37	0.38	3.51
48:	0.38	0.40	0.39	0.39	0.42	0.41	0.41	0.42	0.43	0.45	4.11
49:	0.43	0.44	0.45	0.44	0.47	0.48	0.51	0.52	0.51	0.52	4.78
50:	0.55	0.58	0.60	0.40	0.51	0.53	0.52	0.53	0.53	0.53	5.28
51:	0.53	0.55	0.55	0.53	0.52	0.53	0.55	0.57	0.55	0.57	5.45
52:	0.56	0.56	0.57	0.57	0.58	0.58	0.60	0.60	0.61	0.63	5.85
53:	0.65	0.67	0.70	0.48	0.64	0.63	0.63	0.63	0.64	0.61	6.27
54:	0.62	0.64	0.62	0.62	0.63	0.60	0.59	0.59	0.61	0.63	6.15
55:	0.62	0.60	0.61	0.61	0.63	0.63	0.65	0.68	0.71	0.70	6.45
56:	0.73	0.76	0.81	0.58	0.73	0.71	0.71	0.71	0.71	0.69	7.15
57:	0.72	0.70	0.68	0.71	0.69	0.68	0.68	0.66	0.65	0.66	6.83
58:	0.67	0.68	0.67	0.66	0.66	0.69	0.68	0.68	0.68	0.69	6.77
59:	0.69	0.69	0.72	0.52	0.54	0.57	0.57	0.53	0.52	0.51	5.86
60:	0.49	0.49	0.46	0.44	0.43	0.40	0.39	0.37	0.36	0.37	4.20
61:	0.36	0.33	0.34	0.34	0.32	0.31	0.31	0.31	0.29	0.29	3.19
62:	0.30	0.28	0.27	0.22	0.19	0.22	0.20	0.19	0.18	0.18	2.23
63:	0.18	0.17	0.16	0.15	0.14	0.14	0.13	0.12	0.12	0.12	1.43
64:	0.12	0.12	0.13	0.11	0.11	0.11	0.10	0.11	0.10	0.11	1.13
65:	0.10	0.10	0.10	0.10	0.06	0.09	0.08	0.08	0.07	0.07	0.83
66:	0.07	0.06	0.06	0.06	0.06	0.05	0.06	0.05	0.05	0.05	0.58
67:	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.49
68:	0.05	0.05	0.05	0.05	0.03	0.05	0.04	0.04	0.04	0.04	0.46
69:	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.40
70:	0.04	0.04	0.04	0.04	0.04	0.03	0.04	0.04	0.04	0.04	0.37

71:	0.03	0.04	0.03	0.03	0.02	0.03	0.03	0.02	0.02	0.02	0.29
72:	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.17
73:	0.02	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.15
74:	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.10
75:	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.01	0.01	0.01	0.06
76:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04
77:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03
78:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
79:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
80:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
81:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
82:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
83:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
84:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
85:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
86:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
87:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
88:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
89:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
90:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Exceedance Chart

S001_BJK020008_07122014_210841: Exceedance Chart

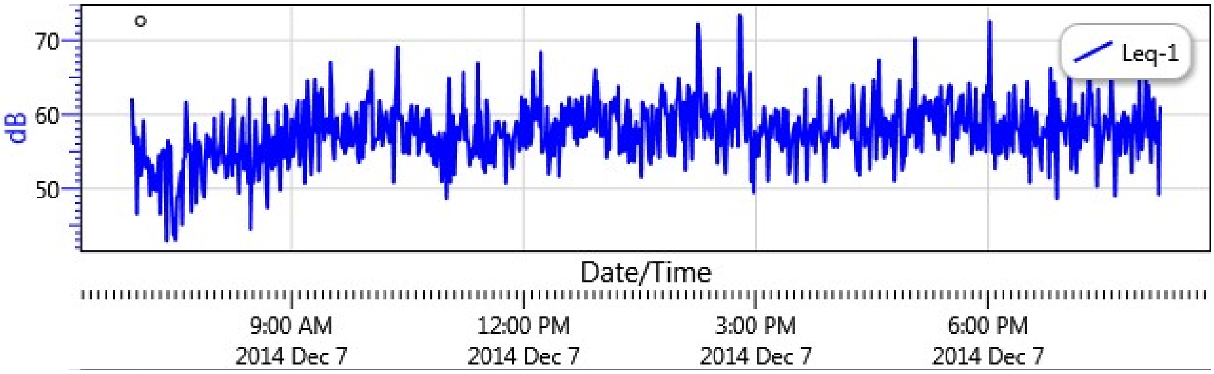


Exceedance Table

.	0%	1%	2%	3%	4%	5%	6%	%7	%8	%9
0%:		70.6	68.1	66.2	64.9	64.0	63.2	62.6	62.1	61.8
10%:	61.5	61.1	60.9	60.6	60.3	60.1	59.9	59.7	59.5	59.3
20%:	59.1	59.0	58.9	58.7	58.6	58.4	58.3	58.1	58.0	57.8
30%:	57.7	57.5	57.4	57.2	57.1	56.9	56.8	56.7	56.5	56.4
40%:	56.2	56.1	56.0	55.8	55.7	55.5	55.4	55.2	55.1	54.9
50%:	54.7	54.6	54.4	54.2	54.1	53.9	53.8	53.6	53.4	53.3
60%:	53.1	53.0	52.8	52.6	52.5	52.3	52.1	51.9	51.8	51.6
70%:	51.4	51.2	51.0	50.8	50.7	50.5	50.3	50.1	49.9	49.7
80%:	49.5	49.3	49.1	48.9	48.6	48.4	48.1	47.9	47.6	47.3
90%:	47.0	46.7	46.4	46.1	45.7	45.3	44.9	44.3	43.7	42.9
100%:	39.4									

Logged Data Chart

S001_BJK020008_07122014_210841: Logged Data Chart



Summary Data Panel

Description	Meter	Value	Description	Meter	Value
Leq	1	--			
Exchange Rate	1	3 dB	Weighting	1	A
Response	1	SLOW	Bandwidth	1	OFF
Exchange Rate	2	3 dB	Weighting	2	A
Response	2	SLOW			

MEA

Industrial Hygiene Division

APPENDIX E

Monitoring Equipment Data

ARGUS-HAZCO

Certificate of Compliance and Calibration

	Certificate Number	5/19/2014 - 1082	
Make/Model	QC-20	**Cal Date:**	5/19/2014
Asset#	0003025	**Next Cal Due:**	5/19/2015
Serial Number	QOH040007		

Argus-Hazco does hereby certify that the above listed equipment is to be in physical, mechanical working order and within the manufacturer's acceptable limits. Each unit is tested and inspected in accordance with prescribed procedures before each rental.

This report may be reproduced in its entirety only with written approval of Argus-Hazco

Notes

Location	Detroit, MI	***Asset Released In Tolerance***	☑
Technician	DS	***All Tests Passed***	☑
Date	5/19/2014		
Time	9:45:11 AM		
SOP#			

Quality Control: **Date:**

Please Note: All tests performed with NIST Traceable test and measurement equipment at ambient room temperature, humidity, and pressure at the location listed above. Time in transit or any change in temperature, pressure, humidity, or elevation may result in changes to the calibration values listed. Performance of a field calibration is recommended prior to each use; refer to owner's manual for calibration procedures. Use of this test sheet constitutes proof that the testing environment was within manufacturers' limitation and the instrument conforms to manufacturers' specification.

ARGUS-HAZCO

Certificate of Compliance and Calibration

Certificate Number **4/8/2014 - 1007**

Make/Model	SOUNDPRO	**Cal Date:**	4/8/2014
Asset#	1123826	**Next Cal Due:**	4/8/2015
Serial Number	BJK020008		

Argus-Hazco does hereby certify that the above listed equipment is to be in physical, mechanical working order and within the manufacturer's acceptable limits. Each unit is tested and inspected in accordance with prescribed procedures before each rental.

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Notes

Location	Detroit, MI	***Asset Released In Tolerance***	☑
Technician	DS	***All Tests Passed***	☑
Date	4/8/2014		
Time	11:18:33 AM		
SOP#			

Quality Control: **Date:**

Please Note: All tests performed with NIST Traceable test and measurement equipment at ambient room temperature, humidity, and pressure at the location listed above. Time in transit or any change in temperature, pressure, humidity, or elevation may result in changes to the calibration values listed. Performance of a field calibration is recommended prior to each use; refer to owner's manual for calibration procedures. Use of this test sheet constitutes proof that the testing environment was within manufacturers' limitation and the instrument conforms to manufacturers' specification.

QC'd by: JT

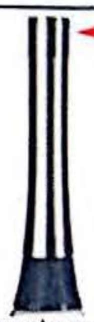
QC date: 12-3-14

ARCUS-HAZCO

NOTE: Inspect unit and accessories, if you have any questions call 800-332-0435
Items missing upon return will be charged to your order

Included with the SoundPro


SoundPro


Microphone

Note: Do not remove Preamp from base

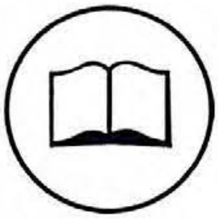

59-344
Windscreen


56-164
Strap


056-990
Cal Adapter


53-575
USB cable


Detection Management Software


Manual


Pelican Case
May be different case that you get

Listed below are the OPTIONAL kits for the Soundpro

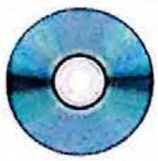
494-0018


Tripod

415-1012


QC10

Several Versions


software

415-0005

ARGUS-HAZCO

Certificate of Compliance and Calibration

Certificate Number	4/8/2014 - 1004

Make/Model	SOUNDPRO	Cal Date:	4/8/2014
Asset#	1096347	Next Cal Due:	4/8/2015
Serial Number	BJI020017		

Argus-Hazco does hereby certify that the above listed equipment is to be in physical, mechanical working order and within the manufacturer's acceptable limits. Each unit is tested and inspected in accordance with prescribed procedures before each rental.

Notes

Location	Detroit, MI	***Asset Released In Tolerance***	☑
Technician	DS	***All Tests Passed***	☑
Date	4/8/2014		
Time	11:16:59 AM		
SOP#			

Quality Control: **Date:**

Please Note: All tests performed with NIST Traceable test and measurement equipment at ambient room temperature, humidity, and pressure at the location listed above. Time in transit or any change in temperature, pressure, humidity, or elevation may result in changes to the calibration values listed. Performance of a field calibration is recommended prior to each use; refer to owner's manual for calibration procedures. Use of this test sheet constitutes proof that the testing environment was within manufacturers' limitation and the instrument conforms to manufacturers' specification.

QC'd by: JT 12-3-14

QC date: 12-3-14

ARGUS-HAZCO

NOTE: Inspect unit and accessories, if you have any questions call 800-332-0435
Items missing upon return will be charged to your order

Included with the SoundPro

SoundPro

Microphone

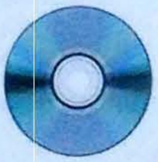
Note: Do not remove Preamp from base

59-344
Windscreen

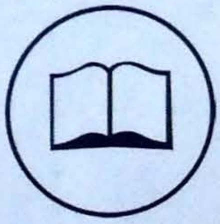
56-164
Strap

056-990
Cal Adapter

53-575
USB cable



Detection
Management
Software



Manual

Pelican Case
May be different
case that you get

Listed below are the OPTIONAL kits for the Soundpro

494-0018

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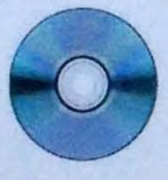
415-1012

QC10

Several Versions



software

415-0005

FR. 415-2024 PLEASE RETURN THIS SHEET Nov 1, 2013

N

Legend

- Location of Photo
- Approximate Stack Location
- Other Greenup County Parcel
- Greenup County Residential Parcel
- Proposed Project Boundary

0 300 600 1,200

Scale In Feet

BASE MAP SOURCE:
National Agricultural Imagery Program, 2013

SunCoke Energy
South Shore Facility

CONCEPTUAL VIEWSHED FROM
SAND HILL NEIGHBORHOOD

DATE: 12/11/2014	
CREATED BY: KB	CHECKED BY: JP
JOB NO. 25368724	URS

SCHWAKE, DAVID J.

From: SCHWAKE, DAVID J.
Sent: Wednesday, January 08, 2014 11:51 AM
To: 'Pullin, Tanya (State Rep.) (LRC)'
Cc: Bryant, Bart (KYTC-D09)
Subject: RE: South Shore - Truck Overpass from US-23 (Business Confidential)

Agreed, look forward to your call.

We totally understand Spring 2016 is out of the question for a completed overpass. In the below email I have given an updated first production date of Q1 2017. If we assume a completed overpass in Q1 2017, say by end of March, maybe this puts us at October 2014 commitment on starting the project?

Thanks for your continued support!

David Schwake
SunCoke Energy
Director, Business Development North America
(215) 384-5920

From: Pullin, Tanya (State Rep.) (LRC) [mailto:Tanya.Pullin@lrc.ky.gov]
Sent: Wednesday, January 08, 2014 10:51 AM
To: SCHWAKE, DAVID J.
Cc: Bryant, Bart (KYTC-D09)
Subject: RE: South Shore - Truck Overpass from US-23 (Business Confidential)

Dear David, I will give you a call here in just a few minutes.

As we have discussed many times, it will take a set amount of time to design and construct the overpass and that work cannot begin until SunCoke is committed to building on the site. The last date that you spoke of in our meetings for hopeful completion of the overpass was Spring of 2016. For the overpass to be completed by that time, it would have been necessary for SunCoke to announce and be committed to building the facility by Oct 2013 according to Bart Bryant, the Chief District Engineer for our region of the Kentucky Highway Department.

As SunCoke's time table seems to have changed, it will very useful for Bart to know your expected completion date so that an estimate of the design and construction time can be given. With the information on your new time table Mr. Bryant can let us know at what point it will be necessary for SunCoke to announce and commit to building the facility to give enough time to complete the overpass under your new time table.

Looking forward to speaking with you in a few minutes.

From: SCHWAKE, DAVID J. [mailto:DJSCHWAKE@suncoke.com]
Sent: Tuesday, January 07, 2014 11:12 AM
To: Bryant, Bart (KYTC-D09); Eldridge, Darrin (KYTC-D09)
Cc: Pullin, Tanya (State Rep.) (LRC)
Subject: South Shore - Truck Overpass from US-23 (Business Confidential)
Importance: High

Happy New Year,

As you may have seen in local newspaper articles we continue to progress with permitting of the South Shore heat recovery coke plant project.

We had the opportunity in Fall 2013 to meet again with CSX and gain agreement on the latest general arrangement layout.

Receiving the draft air permit gives us a more firm project schedule to work with customers.

Attached is the current general arrangement layout along with some estimated material take off for the bridge as well as some more detail assumptions on the bridge (height, span, etc.). Hatch worked with guidelines from CSX.

As we discussed at our last visit at the site, the Hwy 23 entrance to the bridge/overpass would be in a different location than the current entrance to accommodate the required changes in the layout and to allow for a perpendicular crossing (shortest run) across the rail tracks.

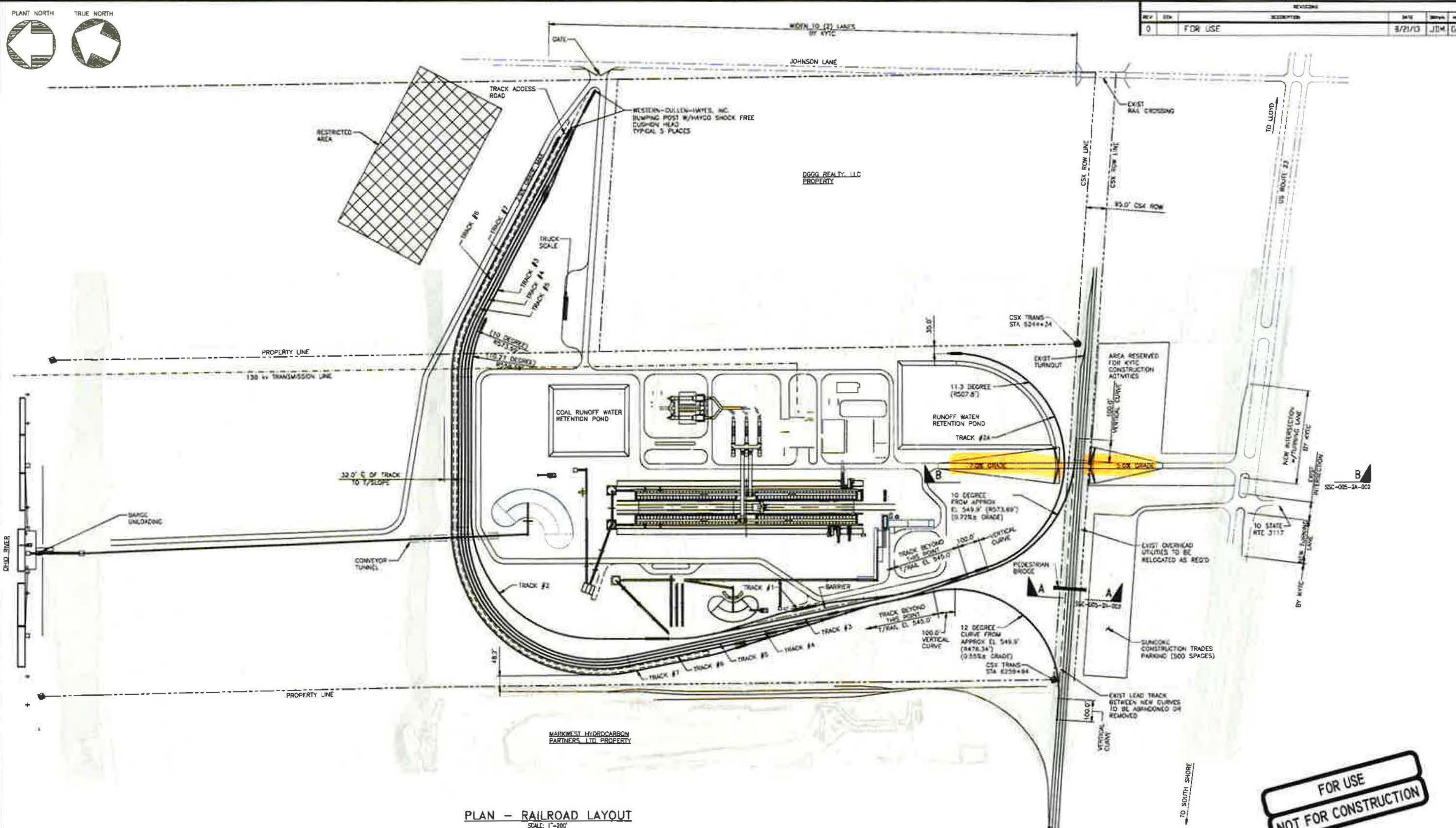
The plan for construction would be an entrance off of Hwy 23 for construction workers to enter construction parking and a foot bridge over the railroad. Construction vehicles and heavy equipment would enter Johnson's lane and an access road to the site would be constructed. There would be a separate laydown/parking area for the bridge construction. We continue to assume this would be a KYDOT project that could be completed by the time of operation.

Bart/Darrin, can you guys work with this information to create an updated cost and schedule as a KYDOT run project? We can bake into our general arrangement any suggestions you may have on design/layout. Our current assumption is start of construction late 2014 to early 2015 with first coke production early 2017 as a rough guideline.

I appreciate your continued support on this project.

David Schwake
SunCoke Energy
Director, Business Development North America
(215) 384-5920

REV	ECN	DESCRIPTION	DATE	DRAWN	APPR
0		FOR USE	8/21/13	JDM	GJR



PLAN - RAILROAD LAYOUT

SCALE: 1"=200'

LEGEND:

- PROPERTY LINE
- TRACKWORK (NEW)
- TRACKWORK (TO REMAIN)
- TRACKWORK (ABANDONED/REMOVED)
- SITE ROAD (PRIMARY)
- SITE ROAD (SECONDARY)
- SITE ROAD (SERVICE)
- EXISTING ROAD/FEATURE
- ROADWORK BY KYTC
- TRANSMISSION LINE

REFERENCE:

"SURVEY OF THE JOHN R. McGINNIS ET-UX PROPERTY FOR SUNCOKE ENERGY NEAR SOUTH SHORE" BY HOWERTON ENGINEERING & SURVEYING PLLC ON OCTOBER 17, 2008.

HATCH

REVISION	SCALE: AS NOTED	DATE
	T. KAISER	8/10/13
	J. MASON	8/16/13
	D. WALKOWSKI	8/14/13
	G. RUDOWSKI	8/21/13
PROJECT NO. 341500		0

UNLESS OTHERWISE SPECIFIED

DIMENSIONS ARE IN INCHES

THIS DRAWING CONTAINS PROPRIETARY INFORMATION WHICH IS TO BE HELD CONFIDENTIAL AND MAY NOT BE REPRODUCED OR DISCLOSED TO OTHERS WITHOUT THE PRIOR WRITTEN CONSENT OF THE SUN COKE COMPANY INC OR DULY AUTHORIZED REPRESENTATIVE THEREOF.

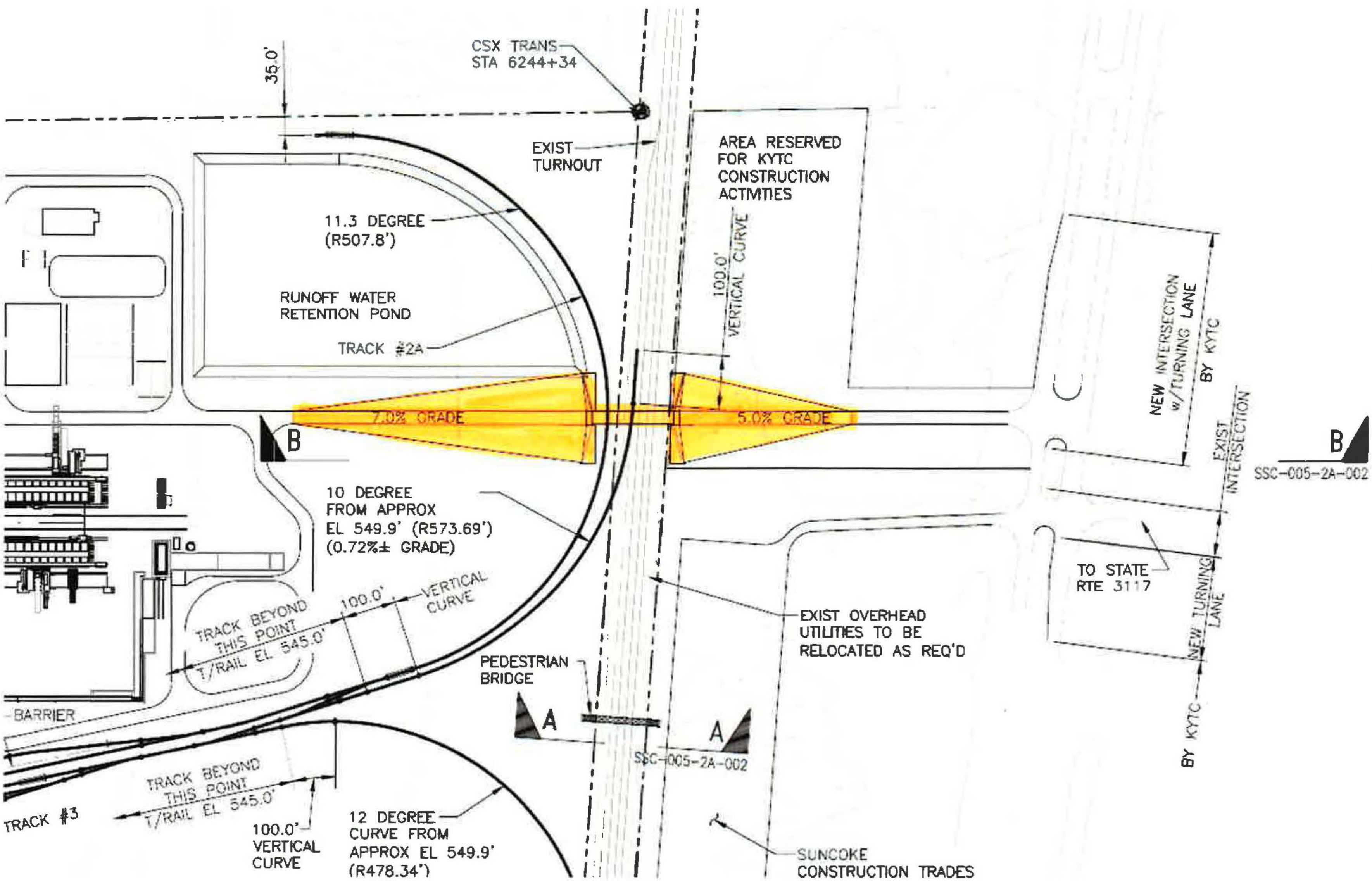
N/A

SunCoke Energy

PROJECT RAVEN
SOUTH SHORE, KENTUCKY

660K TPY HEAT RECOVERY COKE PLANT
RAILROAD - OVERALL PLAN

SIZE: D | DWG NO. SSC-005-2A-001 | REV 0



35.0'
CSX TRANS
STA 6244+34
EXIST
TURNOUT
AREA RESERVED
FOR KYTC
CONSTRUCTION
ACTIVITIES
11.3 DEGREE
(R507.8')
100.0'
VERTICAL CURVE
RUNOFF WATER
RETENTION POND
TRACK #2A
NEW INTERSECTION
w/TURNING LANE
BY KYTC
7.0% GRADE
5.0% GRADE
B
B
EXIST
INTERSECTION
SSC-005-2A-002
10 DEGREE
FROM APPROX
EL 549.9' (R573.69')
(0.72%± GRADE)
TO STATE
RTE 3117
NEW TURNING
LANE
100.0'
VERTICAL
CURVE
TRACK BEYOND
THIS POINT
T/RAIL EL 545.0'
EXIST OVERHEAD
UTILITIES TO BE
RELOCATED AS REQ'D
PEDESTRIAN
BRIDGE
BARRIER
A
A
SSC-005-2A-002
BY KYTC
TRACK BEYOND
THIS POINT
T/RAIL EL 545.0'
TRACK #3
100.0'
VERTICAL
CURVE
12 DEGREE
CURVE FROM
APPROX EL 549.9'
(R478.34')
SUNCOKE
CONSTRUCTION TRADES

REV	ECN	DESCRIPTION	DATE	DRAWN	APPR
0		FOR USE	8/21/13	JDM	GJR

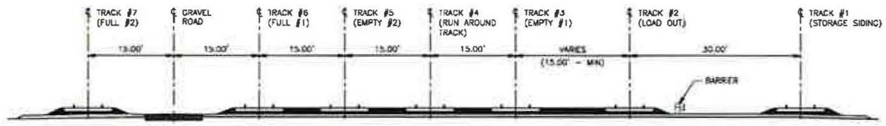
TRACKS (USABLE STORAGE LENGTHS)

#1	STORAGE SIDING	1 YARD ENGINE + 8 CARS	528 LF
#2	LOAD OUT	1 YARD ENGINE + 38 CARS	2144 LF
#2A	LOAD OUT (TRANSFER)	1 YARD ENGINE + 27 CARS	1528 LF
#3	EMPTY #1	67 CARS	3740 LF
#4	RUN-AROUND	N/A	N/A
#5	EMPTY #2	67 CARS	3657 LF
#6	FULL #1	67 CARS	3678 LF
#7	FULL #2	67 CARS	3682 LF

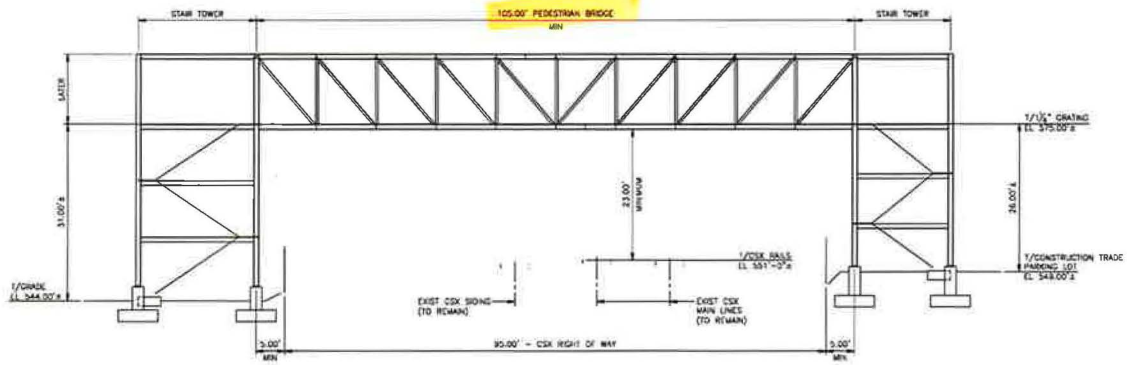
DAILY PRODUCTION: $\frac{\text{60 OVENS * 32 TONS PER OVEN}}{\text{72 TONS PER RAIL CAR}}$ = 27 CARS

TOTAL TRACK = 26,851 FEET (NOT INCLUDING TURNOUTS)
TURNOUTS = 11 TOTAL
CSX ENGINE = 68'-10"
YARD ENGINE = 59'-2"
CAR = 54'-0½"

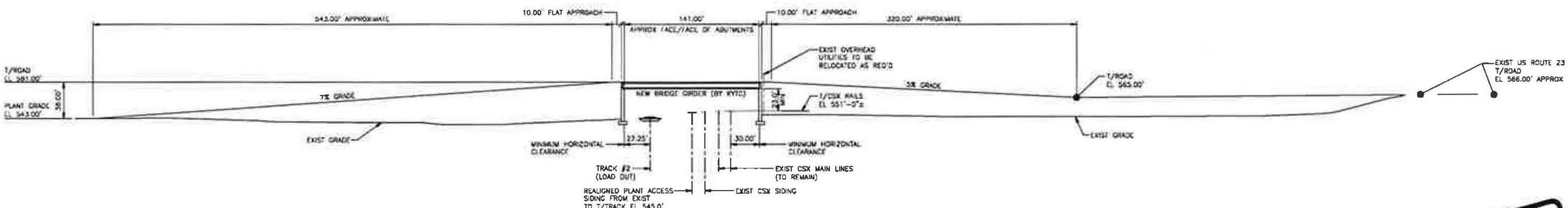
1. ALL CURVES ARE (10 DEGREE) OR LARGER UNLESS NOTED
2. ALL TURNOUTS #10
3. VERTICAL CURVE LENGTH = 100' MINIMUM
4. DISTANCE FROM TURNOUT TO CURVE OR TURNOUT = 50' MINIMUM



STANDARD RAILWAY CROSS SECTION
SCALE: 1:10



SECTION A-A SSC-005-2A-001
SCALE: 1:10



SECTION B-B SSC-005-2A-001
SCALE: 1:50

FOR USE
NOT FOR CONSTRUCTION

HATCH
Hatch Associates Consultants, Inc.
Pittsburgh, PA 15219-1031

REVISION	SCALE: AS NOTED	DATE
	T. KAISER	8/10/13
	J. MAGON	8/10/13
	D. WALKOWSKI	8/11/13
	G. BUDOWSKI	8/11/13
PROJECT NO. 341500		0

UNLESS OTHERWISE SPECIFIED
DIMENSIONS ARE IN INCHES

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SIGNATURES | DATE
DRAWN
CHECKED
APPROVED

N/A

SunCoke Energy

PROJECT RAVEN
SOUTH SHORE, KENTUCKY

660K TPY HEAT RECOVERY COKE PLANT
RAILROAD - SECTIONS AND DETAILS

SIZE: D | DWG NO. SSC-005-2A-002 | REV 0

HATCH™

JOB NO. H346500

SHEET ______ OF ______

SUNCORE PROJECT RAVEN

DESIGNED BY TPK DATE 11/26/13

VEHICLE BRIDGE from US-23

CHECKED BY ______ DATE ______

QUANTITY SUMMARY

BRIDGE: PL GIRDERS = 6(384.5 plf)(141') = 325,287#
DIAPHRAGM FRAMES = 45(348.1#) = 15,665#
BRACING (WT8x18) = 8(18)(45') = 6480#
GUARD RAILS = 21,268#

368,700#
÷ 2000

184.35 TON

SAY 185 TON

BRIDGE GRATING 4"x5/16 = 3948 SF

NORTH ABUTMENT & RAMP

CONCRETE: FOOTING = 467 cy
WALLS = 289 cy
756 cy

EXCAVATION = 847 cy
BACKFILL = 368 cy

RAMP-FILL = 30,040 cy
GUIDE RAIL = 1086 LF

SOUTH ABUTEMENT & RAMP

CONCRETE: FOOTING = 329 cy
WALLS = 199 cy
528 cy

EXCAVATION = 616 cy
BACKFILL = 277 cy

RAMP-FILL = 19,196 cy

GUIDE RAIL = 640 LF

SCHWAKE, DAVID J.

From: Pullin, Tanya (State Rep.) (LRC) <Tanya.Pullin@lrc.ky.gov>
Sent: Friday, August 30, 2013 2:12 PM
To: SCHWAKE, DAVID J.
Subject: RE: SunCoke South Shore Project Update September 11th (Business Confidential)

Dear David, Always good to hear from you.

Unfortunately, I will not be able to be in Greenup County on September 11 or 12. In Kentucky we pride ourselves on our good Labor/Management relations. One reason for these good relations is the annual Labor/Management Conference. I have been asked and I have agreed to attend the conference this year and because of the travel time, I will not be able to be back to Siloam in Greenup County until about 5 or 6pm on Sept 12.

Of course, I am always happy to talk with you anytime in person or by phone.

I will just take this chance to remind you of our earlier conversation that to have an overpass completed by March of 2016, the highway department engineers say they must begin their work by October 2013. There are design and right of way issues (rail and utility included) that will be in addition to the construction work. I hope this is helpful. Bart Bryant, the chief district highway engineer, will be able to confirm any details with you and he will be very glad to work with you.

Looking forward to talking with you.

From: SCHWAKE, DAVID J. [DJSCHWAKE@suncoke.com]
Sent: Friday, August 30, 2013 12:41 PM
To: Pullin, Tanya (State Rep.) (LRC); Bobby Carpenter (rcarpenter@zoominternet.net); Bob Hammond (bob@ashlandalliance.com); Olson, Rustin (Rustin_Olson@csx.com); Bryant, Bart (KYTC-D09); Eldridge, Darrin (KYTC-D09); Bevington, John
Subject: SunCoke South Shore Project Update September 11th (Business Confidential)

Good morning,

We continue to progress with development of the proposed heat recovery coke plant in South Shore Kentucky. The team is planning to have a site visit on September 11th (and September 12th if needed). The goal of this visit is to provide an update on progress as well as discuss the design and construction specifics surrounding the railroad, overpass, and temporary overpass walkway in relation to the construction period.

We plan on having a morning session from 8:30 to lunch where we discuss an update on the project, the rail layout with CSX, the bridge overpass design into the plant over the railroad with Kentucky and CSX, the walking bridge design with CSX, and then the enhancements to Johnson's lane for construction and operation of the plant. We would also like to discuss utility connections to the plant.

- **Representative Pullin, Judge Carpenter, and Bob we could start the day with a project update or handle this one on one if you prefer outside of the large group, I am flexible, please pass along your availability**

- **Judge Carpenter it would be helpful if we could have the county road manager (I know I met him but forgot his name sorry) available to discuss Johnson's lane and when we discuss the bridge overpass/Hwy 23 entry points**
- **Rusty, Bart, and Darrin can you please confirm this date will work for you or if the message should be delivered to someone else please let me know**
- **We will also need to discuss project schedule and its relation to the bridge overpass funding and construction schedule**

In the afternoon session we will focus more on reviewing modular equipment deliveries to the site via barge, barge unloading, and a haul road from the river we have a logistics specialist coming in but folks are welcome to attend. We also plan to discuss site and close to site laydown areas.

I've attached the latest on the railroad design criteria which also includes the site layout so please handle as confidential business information.

Thanks, feel free to call me at the below number, and enjoy your Labor Day weekend, I wanted to get this out as soon as possible to get things scheduled.

David Schwake
SunCoke Energy
Director, Business Development North America
(215) 384-5920

SCHWAKE, DAVID J.

From:	Eldridge, Darrin (KYTC-D09) <Darrin.Eldridge@ky.gov>
Sent:	Friday, March 22, 2013 6:15 AM
To:	SCHWAKE, DAVID J.
Subject:	RE: Raven Access Road Design

Thanks for the update.

From: SCHWAKE, DAVID J. [mailto:DJSCHWAKE@suncoke.com]
Sent: Thursday, March 21, 2013 3:57 PM
To: Eldridge, Darrin (KYTC-D09); 'Bobby Carpenter (rcarpenter@zoominternet.net)'; Bryant, Bart (KYTC-D09)
Subject: RE: Raven Access Road Design

We do not believe so at this point as there is already the internal rail spur north of the main line that the bridge has to span. We have flexibility on that rail and it should not have to shift should we change the "Y" inlet.

SunCoke Energy

David Schwake
Director, Business Development North Americas
djschwake@suncoke.com
630.824.1948 w
215.384.5920 c
630.824.1001 f
1011 Warrenville Road
Suite 600
Lisle, IL 60532
www.suncoke.com

From: Eldridge, Darrin (KYTC-D09) [mailto:Darrin.Eldridge@ky.gov]
Sent: Tuesday, March 19, 2013 1:32 PM
To: SCHWAKE, DAVID J.; 'Bobby Carpenter (rcarpenter@zoominternet.net)'; Bryant, Bart (KYTC-D09)
Subject: RE: Raven Access Road Design

Mr. Schwake,

We have worked up a very preliminary, conceptual design and estimate meeting the parameters you set forth below. We do have one question, however. Is there an issue with the railroad spur which could potentially change the length of the proposed bridge?

Thanks,
Darrin Eldridge
KYTC, D-9

From: SCHWAKE, DAVID J. [mailto:DJSCHWAKE@suncoke.com]
Sent: Friday, March 15, 2013 3:04 PM
To: Bobby Carpenter (rcarpenter@zoominternet.net); Bryant, Bart (KYTC-D09); Eldridge, Darrin (KYTC-D09)
Subject: FW: Raven Access Road Design

Good afternoon,

See the below from a construction contractor we have used for several of our plants. These are the recommendations for construction road access. As we spoke we plan to utilize Johnson's lane for the heavy construction traffic and need to have the roadway capable to accomplish this including removal of the electrical pole and any other interferences. The right of way was stated as 60 ft and the suggested roadway width is 28 ft wide, a little wider than what we originally discussed which was 24 ft as they recommend a passing shoulder width of 2 ft on both sides. Is this sufficient basis information for design for Johnson's lane?

> The Project Raven site access road structural components should be designed to handle an axel load requirements of not less than a HS-25 loading configuration. Heavy hauls due to construction mobilization or equipment delivery shall be accommodated by trailer axle configurations which lower the eccentric loading of structural bridges and culverts to HS-25 loading.
>
> Flexible pavement design of local roadways is recommended to meet AASHTO pavement design methods converting all traffic into projected ESALS to satisfy the desired design longevity. If local or state standards exceed AASHTO requirements the governing agency shall control.
>
> The recommended roadway width should not be less than 28'. This section would be comprised of 12' travel lanes and a 2' paved shoulder.

SunCoke Energy

David Schwake
Director, Business Development North Americas
djschwake@suncoke.com
630.824.1948 w

215.384.5920 c
630.824.1001 f
1011 Warrenville Road
Suite 600
Lisle, IL 60532
www.suncoke.com

SCHWAKE, DAVID J.

From: Bob Hammond <bob@ashlandalliance.com>
Sent: Wednesday, March 13, 2013 2:55 PM
To: SCHWAKE, DAVID J.
Cc: Bobby Carpenter; Bill Hannah ; Tanya Pullin
Subject: Thanks for meeting with Bobby and I this morning

David,

Thanks for taking time out of your schedule to meet with Bobby and I this morning to discuss Project Raven.

I have called Tanya to let her know that you have a few of items that you would like to discuss with her.

1) The timing of the completion of construction of the bridge to meet your 1st quarter of 2016 target.

2)The timing of the resolution that needs to be completed.

3) How a public roadway is defined.

It was also good to hear that things are going well with Kentucky Power and AEP on the project, Railroad issue is being worked out and you plan to talk with MarkWest, and the permitting progress in moving along in Frankfort.

Please let me know if I have missed anything from the meeting this morning.

If it is OK with you, I would like to send an update to John Bevington (CED), Grant Chaney (CSX), Brad Hall (Kentucky Power), and Tyler Burke (Columbia Gas).

Do I need to contact John and Didi about are meeting today?

Thanks,

Bob

Bob Hammond I Director of Business Development

Ashland Alliance | *Unity, Teamwork, Collaboration*
P.O. Box 830, 1730 Winchester Avenue
Ashland, KY 41105-0830
E-mail: bob@ashlandalliance.com
Phone: 606.324.5111
Mobile: 606.831.0263
Fax: 606.325.4607
Web: www.ashlandalliance.com

SCHWAKE, DAVID J.

From: Eldridge, Darrin (KYTC-D09) <Darrin.Eldridge@ky.gov>
Sent: Tuesday, January 15, 2013 7:22 AM
To: SCHWAKE, DAVID J.
Cc: Bryant, Bart (KYTC-D09); PLATA, KEN J.; 'grudowski@hatch.ca'; 'ckos@hatch.ca'
Subject: RE: Greenup County, KY (Business Confidential)

David,

Thanks, we'll be in touch.

Darrin

From: SCHWAKE, DAVID J. [mailto:DJSCHWAKE@suncoke.com]
Sent: Monday, January 14, 2013 2:30 PM
To: Eldridge, Darrin (KYTC-D09)
Cc: Bryant, Bart (KYTC-D09); PLATA, KEN J.; GRudowski@hatch.ca; ckos@hatch.ca
Subject: RE: Greenup County, KY (Business Confidential)

Darrin,

Sorry, for the delay, I had a bit of a back log coming back from my extended vacation over the holidays. I'm still awaiting maximum dimensions of construction vehicle/crane size from my construction team. However, attached is a mark-up of the latest General Arrangement with comments based on our onsite discussions. The highlighted area is the area we would look to designate for the building of the overpass. Of course, some of this area would be shared where the entrance from Highway 23 comes in to the plant.

As we discussed we will need to understand the dimensions of the bridge and corresponding easements, what criteria qualify for "public access" and how far "down the road" is the access point required, schedule, cost, ongoing maintenance fees, etc.

In this layout we are assuming we would have construction foot traffic entering in with their vehicles to park on the south west corner of the property with a foot bridge over the CSX railroad. Construction vehicle traffic and large equipment would be using Johnson's lane (a 24 ft wide road with a 60 ft easement) and entering into the plant access road shown just south of where the "L" portion of the rail ends.

Bart, based on the high cost of the temporary at grade crossing and the complexities with the mainline and side tracks being at a different elevation we are now assuming we would have the construction vehicle entrance be off Johnson's lane with foot traffic by temporary walking bridge. It appears as if moving the main plant entrance may be required to achieve a perpendicular to rail overpass and to allow for adequate craft parking. This would "split" the traffic pattern coming to the plant which should aid in relieving the potential density issues we would have trying to build an overpass, bring in large construction equipment and vehicle traffic via an at grade crossing, as well as foot traffic across the foot bridge all in the same general location.

If printed in 11X17" the scale should be roughly 1 in = 400 ft, otherwise for ANSI D size it should be 1 in = 200 ft.

Please, let us know your comments, suggestions, concerns, thanks...

SunCoke Energy

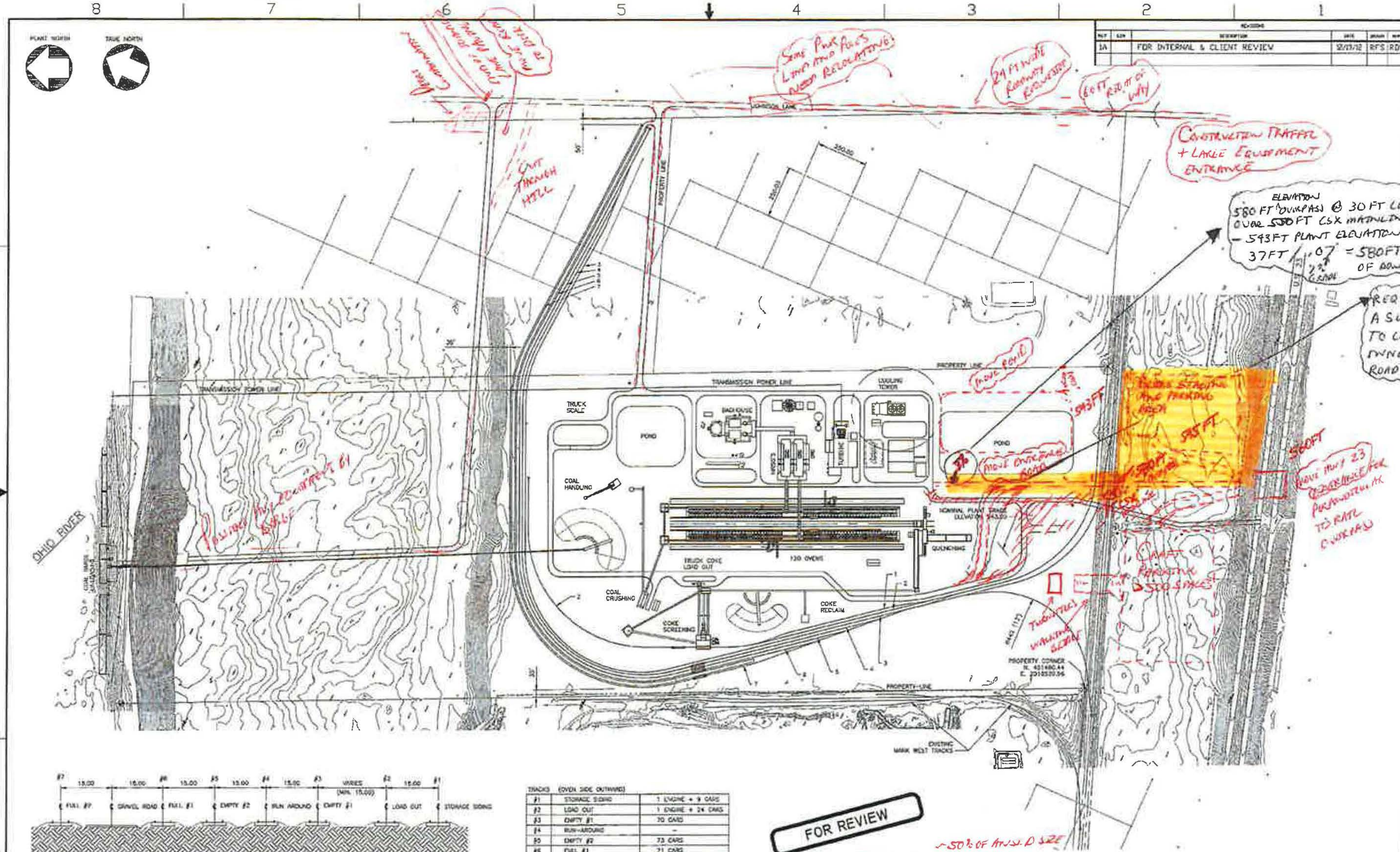
David Schwake
Director, Business Development North Americas
djschwake@suncoke.com
630.824.1948 w
215.384.5920 c
630.824.1001 f
1011 Warrenville Road
Suite 600
Lisle, IL 60532
www.suncoke.com

From: Eldridge, Darrin (KYTC-D09) [mailto:Darrin.Eldridge@ky.gov]
Sent: Wednesday, January 02, 2013 10:10 AM
To: SCHWAKE, DAVID J.
Cc: Bryant, Bart (KYTC-D09)
Subject: Greenup County, KY

Mr. Schwake,

As a follow up from our on-site meeting on January 12th, I was wondering if you had a chance to get me an electronic file of your proposed development.

Thanks,
Darrin Eldridge
Kentucky Transportation Cabinet
Department of Highways, District 9



TRACKS (OVEN SIDE OUTWARD)

#1	STORAGE SIDING	1 ENGINE + 9 CARS
#2	LOAD OUT	1 ENGINE + 24 CARS
#3	EMPTY #1	70 CARS
#4	RUN-AROUND	–
#5	EMPTY #2	73 CARS
#6	FULL #1	71 CARS
#7	FULL #2	72 CARS

DAILY PRODUCTION: 60 OVENS *30 TONS PER OVEN / 75 TONS PER RAIL CAR – 24 CARS

TOTAL TRACK = 28,653 FEET 13 #10 TURNOUTS

ALL INSIDE CURVES 574' RAD. (10°) UNLESS NOTED.

FOR REVIEW

~50% OF ANSI D SIZE

HATCH Hatch Associates Consultants, Inc. Pittsburgh, PA

REVISION	SCALE: 1"=200'	DATE
1A FOR INT. & CLIENT REVIEW		
PROJECT NO. 341500		1A

SunCoke Energy

PROJECT RAVEN
SOUTH SHORE, KENTUCKY

660K TPY RECOVERY COKE PLANT
RAILROAD LAYOUT (OPTION "B")

341500-50-042-0035

D SSC-005-2A-035 1A

PAVEMENT WIDENING ON CURVES (cont.): Standard Drawing RGS-001 and **Chapter 3** of *A Policy on Geometric Design of Highways and Streets* is to be used to determine the amount of widening for a particular radius of a curve. When spiral transition curves are used, the widening between the inside and outside edges of pavement is to be divided equally. The widening is to transition from zero at the tangent to spiral (T.S.) to full widening at the spiral to curve (S.C.).

When spiral transition curves are not used, all the widening is to be done on the inside edge of pavement. The widening is to transition from zero at the beginning of the tangent runoff (L) to full widening at the point of full superelevation. Transition ends are to avoid an angular break at the edge of pavement.

SIGHT DISTANCE ON HORIZONTAL CURVES: The sight distance on a horizontal curve is measured along the center line of the inside lane of the curve. In some cases, objects such as cut slopes, vegetation, or buildings obstruct the sight distance. When designing the horizontal alignment, the designer is to check into obtaining adequate sight distance on horizontal curves. In some instances, additional right of way may be required.

For horizontal curves, both passing sight distance and stopping sight distance are to be considered. Passing sight distance is recommended for consideration only on tangents and very flat curves. Sight distance restrictions on sharper curves make this consideration prohibitive. Sight distance for horizontal curves is to be coordinated with the sight distance for vertical curves (see **page 7**).

An additional subject to consider in roadway design is intersection sight distance for roads with at-grade intersections. **Chapter HD-902,** "At-Grade Intersections," and *A Policy on Geometric Design of Highways and Streets* provide insight.

VERTICAL ALIGNMENT: The terrain of the traversed land influences the design of the roadway. Terrain is generally classified into three categories: level, rolling, and mountainous. Like horizontal alignment, vertical alignment consists of tangent sections and curves.

GRADES: The design speed and type of terrain establish the suggested maximum grades. The suggested maximum grades are shown in **Exhibits 700-01, 700-02, 700-03, and 700-04** of this manual. Also considered in the design process are the types of vehicles expected on the roadway. The effect of grade is far more pronounced on truck speeds than on the speeds of passenger cars. In addition to the grade percentage, the length of grade is also very important. **Chapter 3** of *A Policy on Geometric Design of Highways and Streets* shows how to determine critical lengths of grade.

CONT.

GRADES (cont.):

A Policy on Geometric Design of Highways and Streets suggests a maximum grade of 5 percent for a design speed of 70 miles per hour and 7 to 12 percent for a design speed of 30 miles per hour. The maximum design grade is not to be considered the desirable grade to achieve on a roadway. Where feasible, it is recommended that grades be less than the maximum allowable. However, grades less than 500 feet in length and one-way downgrades may be approximately 1 percent steeper than the maximum. Such a grade may be increased to 2 percent if on a low-volume rural highway. Steeper grades may also be used where extremely high construction costs would be encountered to produce flatter grades. Care is to be taken when increasing grade in rural areas because the increase may introduce the need for truck-climbing lanes. The project team is to discuss the use of grades steeper than the maximum, and the project manager is to document the use in the Preliminary Line and Grade Report and in the Design Executive Summary.

* VERTICAL CURVE GEOMETRY SHOULD BE CONSIDERED OVER 5-7% BASED ON TRUCK TRAFFIC VERTICAL CLEARANCES

It is necessary to maintain a minimum grade in order to provide adequate drainage. Level grades may be used on uncurbed, nonsuperelevated roadways as long as there is an adequate crown. It is recommended that curbed roadways maintain a minimum grade of 0.50 percent. A grade of 0.30 percent may be considered if there is a high-type, adequately crowned pavement.

The maximum suggested grades for entrances are shown in Standard Drawing RPM-110.

VERTICAL CURVES:

The introduction of vertical curves affects the transition from one rate of grade to another and usually consists of a parabolic curve. Vertical curves are either the crest or sag type, depending on the positive or negative slopes of the intersecting grades. Any standard route-surveying textbooks for details on the method of calculating vertical curves may be referenced.

A common means to determine the minimum length of curve needed for various design speeds is K, the rate of curvature. K is determined by dividing the length of vertical curve (L) by the algebraic difference (A) in grades (L/A). K is the horizontal distance required to effect a 1 percent change in gradient.

After K is found, the minimum length of vertical curve (L) can be calculated by using information in **Chapter 3** of *A Policy on Geometric Design of Highways and Streets.* Suggested lengths of vertical curve for a given design speed are based on sight distance for crest vertical curves and on headlight sight distance for sag vertical curves.

In addition to sight distance, the designer is to also consider appearance and riding comfort when selecting a length of vertical curve. Long vertical curves give a more pleasing appearance and provide a smoother ride than short vertical curves.

CONT.

SIGHT DISTANCE ON VERTICAL CURVES:

The design of both crest and sag vertical curves are dependent on stopping sight distance calculations:

- **Crest Vertical Curves:** The stopping sight distance is based on the height of eye of 3.5 feet and the height of object of 2 feet.

- **Sag Vertical Curves:** The stopping sight distance is based on a 2-foot headlight height and a 1-degree angle of light spread upward from the headlight beam.

The stopping sight distance values for various design speeds listed in **Chapter 3** of *A Policy on Geometric Design of Highways and Streets* are to be minimum values. Generally, it is not practical to design crest vertical curves to provide for passing sight distance because required distances are 7 to 10 times longer than on a tangent or a sag condition. **Chapter 3** of *A Policy on Geometric Design of Highways and Streets* details stopping sight distance design controls.

CROSS-SECTIONS:

To determine the typical cross-section for a given highway, designers are to use four basic design controls:

- Functional classification
- Area (rural or urban)
- Volume of traffic
- Design speed

The context of the project (Environmental, Right of Way, Utilities, Pedestrians, and other considerations) may affect selection of the typical cross-sections.

The Common Geometric Practices (**Exhibits 700-01** through **700-04** of this manual) with the approved geometric design are to be used to determine the typical cross-section. **Exhibits 700-05** through **700-07** show example typical sections. Cross-section items include the following:

- Pavement slope and width
- Shoulder width and slope
- Curb placement
- Typical earth slopes in cuts and fills

Traveled ways located in tangent sections usually have a crown or high point located in the center and a cross-slope down to the edges of pavement. Divided multilane highways may be crowned separately as a two-lane highway, or they may have a unidirectional cross-slope across the entire width of traveled way. The rate of cross-slope is important. Steep slopes minimize ponding of water, but they may be uncomfortable to the driver. It is recommended that the cross-slope range from 1.5 to 2 percent.

CONT.

January 22, 2014
Kentucky Power Meeting Notes

Attendees:
Ky Power (KP): Scott Mann, Mike Hurley, Brad Hall, Greg Pauley (KP president, partial meeting)
SunCoke Energy (SE): Dave Schwake, Lisa Natter, Kenneth Kreider (KMK Law)
PowerSecure: Chad Buchanan, Jerry King

1.) Scott Mann – no issues with the SE installation timeframe for both construction and prime power.
2.) Mike Hurley – some improvement needs to be made to the 69KV line to increase conductor size to serve the SE load. (note: service point for Suncoke is less than 1 mile from the KP 138KV/69KV substation – question would be how far down the 69KV line would KP have to upgrade – would assume down to the Suncoke tap point but would they have to go further for relaying and line protection purposes which would increase the costs? This cost would be part of the costs to serve Suncoke and be part of the compensatory calculations.)
3.) Mike Hurley – didn't believe there would be an issue in allowing a backup service (at a certain capacity) from the South Shore side of the 69KV line. He would need to check capacity to see how the South Shore transformer was loaded.
4.) Mike - Intent is to serve SE off the 69KV once it crossed the railroad to minimize permit requirements. (David indicated that this may not be such an issue due to permits being developed for the other utilities). KP would need to be granted a 100ft right of way for this tap line from the 69KV line back to the site and metering station. Location of easement and metering point to be determined once SE evaluate other requirement for this area.
5.) Scott / Mike – would need a 10 X 10ft 'deeded' space for metering if a Line Tap (probably an in line manual 3 phase air break – MOAB - and fuses) was required to serve SE. (discussion around the possibility of a 4 breaker switching station – Our sense after thinking about it is since the KP 138KV/69KV substation is so close, that KP would isolate the 69KV line to serve the SE from Southshore by isolating the line at their 138KV/69KV transformer if the 138KV line went down. SE's only exposure is the mile of 69KV line between the KP sub and their SE tap point. This possibility is worth checking into – especially if they could do this remotely).
6.) KP would engineer and construct all their required line changes and metering upgrades themselves. Note that SE would be responsible for their 69KV line from the KP metering point to the SE step down substation. SE would also be responsible for building their substation and the distribution into the plant. It would need to be evaluated due to site conditions whether a second 69KV line into the site would be of benefit for reliability.
7.) Scott – provided a distribution one line of the 12KV system nearby the property. Potential for using the existing metering point (and step down transformer?) if the capacity requirement matched. Any changes or additions required for construction power would be at SE expense.

(SE is to put together a plan – connected load, largest motor, etc.- so that KP can evaluate effects (flicker, loading, protection) on their distribution circuit.

8.) Scott – didn't think there would be any need for 'aid for construction' for prime power based on Scott's preliminary calculation.

9.) Scott - 10MW load would fit the KP standard CIP-TOD standard tariff – Commercial and Industrial Power / Time of Day) - no special tariff required. If the load demand was below 7.5MW, the KP tariff QP (Quantity Power) would be an option. (Note: the CIP-TOD tariff has a $12.06/KW demand / 2.906 cent energy charge verses QP having a $10.13/KW demand / 3.2 cent energy charge. To select the proper tariff, SE would need to evaluate their load factor and benefit for shift loads for the TOD benefits if their load requirement were less than 7.5MW. – also note the $0.69/KVAR for reactive demand in excess of 50 percent of KW of monthly metered demand may make designing into switching capacitor into the SE system a benefit). SE to check exact capacity requirements.

10.) Mike – be careful with the QP off peak rate calculation being different than the CIP – TOD calculation (covers only the difference between off and on peak amounts).

11.) Scott – It would be of benefit to have a Letter of Commitment (Intent) from SE to allow AEP to start some advance planning on their transmission line. This SE commitment would cover expenses if the project didn't provide forward. The expenses would roll into the project and be part of the compensatory calculations. This Letter of commitment is the only document needed by KP. This Intent document would lay out rate, capacity, tariff, requirements. KP may require some form of Security Agreement (deposit).

12.) Scott – no DSM incentives for VFD's, energy efficiency improvements. (No DSM for Industrials in KY.)

13.) Scott – no issue voiced for SE self-supply (from their STG) if KP 69KV line goes down. (Note: SE to spec out exactly what is critical for back-up – this will help in assisting KP in determining whether they have available capacity from South Shore.)

14.) Mike – if automatic backup capacity is required, the KP ASF tariff would be used (including an estimated $4/KW capacity fee). Once the South Shore transformer capacity is reviewed, KP may not require a capacity fee but allow use of the backup line at KP control. If additional costs were required to allow the 69KV line to back feed SE, these costs would also be included in the compensatory calculations. (Note: it is of economic benefit (spin the meter) to KP to find a way to serve SE if they are down instead of SE self-supply. It is also of commercial benefit to KP to find another efficient way to serve SE instead of having a large very visual customer down.)

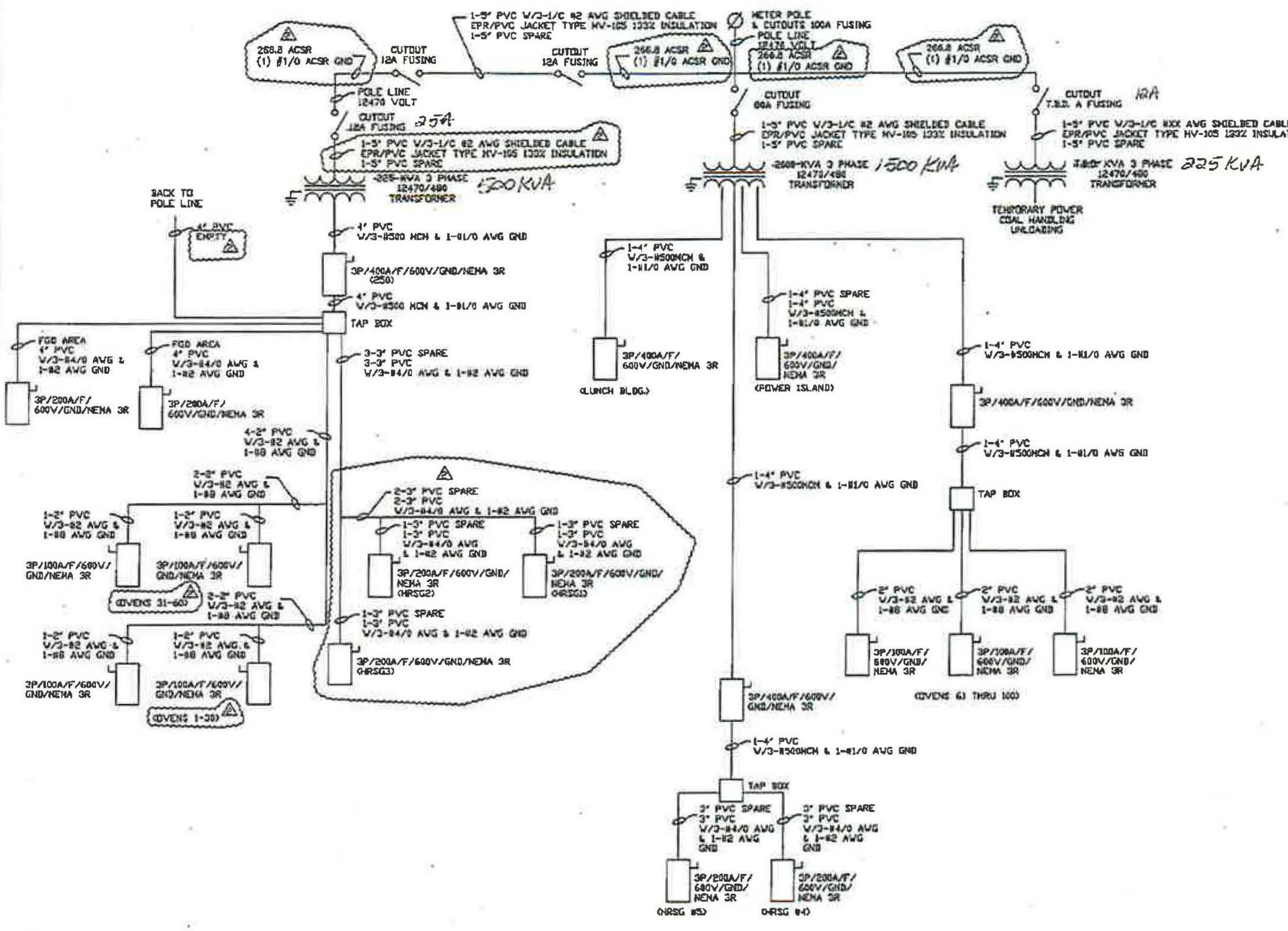
3004301_page_2

Kentucky Power
REGION: Charleston DISTRICT: Pikeville

Station is on: 3004301 page 1

SCALE = 1"=1031'

REV	DESCRIPTION	DATE	DRAWN	APPR
2	REVISED	5/7/10	REM	



SHORT CIRCUIT DATA					
SOURCE	VOLTAGE	PHASE	CALC TYPE	SYMMT CURRENT	ASSYM CURRENT
DUKE	12,470	3	P-P G-F	27,336 27,336	34,217 34,217
2000KVA CUTOUT	12,470	3	P-P G-F	15,917 5,267	17,276 5,398
225KVA CUTOUT	12,470	3	P-P G-F	13,152 3,735	13,951 3,813
225KVA CUTOUT	12,470	3	P-P G-F	12,657 3,475	13,199 3,514
225KVA CUTOUT	12,470	3	P-P G-F	10,932 2,765	11,343 2,820
12000KVA TRANSFORMER	12,470	3	P-P G-F	14,064 3,966	14,372 3,975
3000KVA SECONDARY	480	3	P-P G-F	37,689 30,597	42,659 32,513
T.B.D. SWITCH	480	3	P-P G-F	27,787 11,323	29,750 11,545
HRSG SWITCH	480	3	P-P G-F	29,165 12,648	31,157 12,837
OVEN SWITCH	480	3	P-P G-F	29,165 12,648	31,157 12,837
225KVA TRANSFORMER	12,470	3	P-P G-F	10,722 2,695	11,059 2,721
225KVA SECONDARY	480	3	P-P G-F	7,133 6,657	8,216 7,511
SAFETY SWITCH	480	3	P-P G-F	6,705 4,655	7,430 4,991
TBD KVA CUTOUT	12,470	3			
TBD KVA TRANSFORMER	12,470	3			
TBD KVA SECONDARY	480	3			

NOTE:
1. GROUNDING TO BE IAW NEC ARTICLE 250.
2. METER POLE & CUTOUTS CONSTRUCTED TO DUKE ENERGY SPECIFICATIONS.
3. POLE LINE CONSTRUCTED PER UNITED STATES DEPARTMENT OF AGRICULTURE, RURAL ELECTRIFICATION ADMINISTRATION BULLETIN 50-3, STANDARD D-804
4. ALL FUSES TO BE CURRENT LIMITING TYPE.

kokosing CONSTRUCTION COMPANY INC.

N/A

Middletown Coke Company Inc.

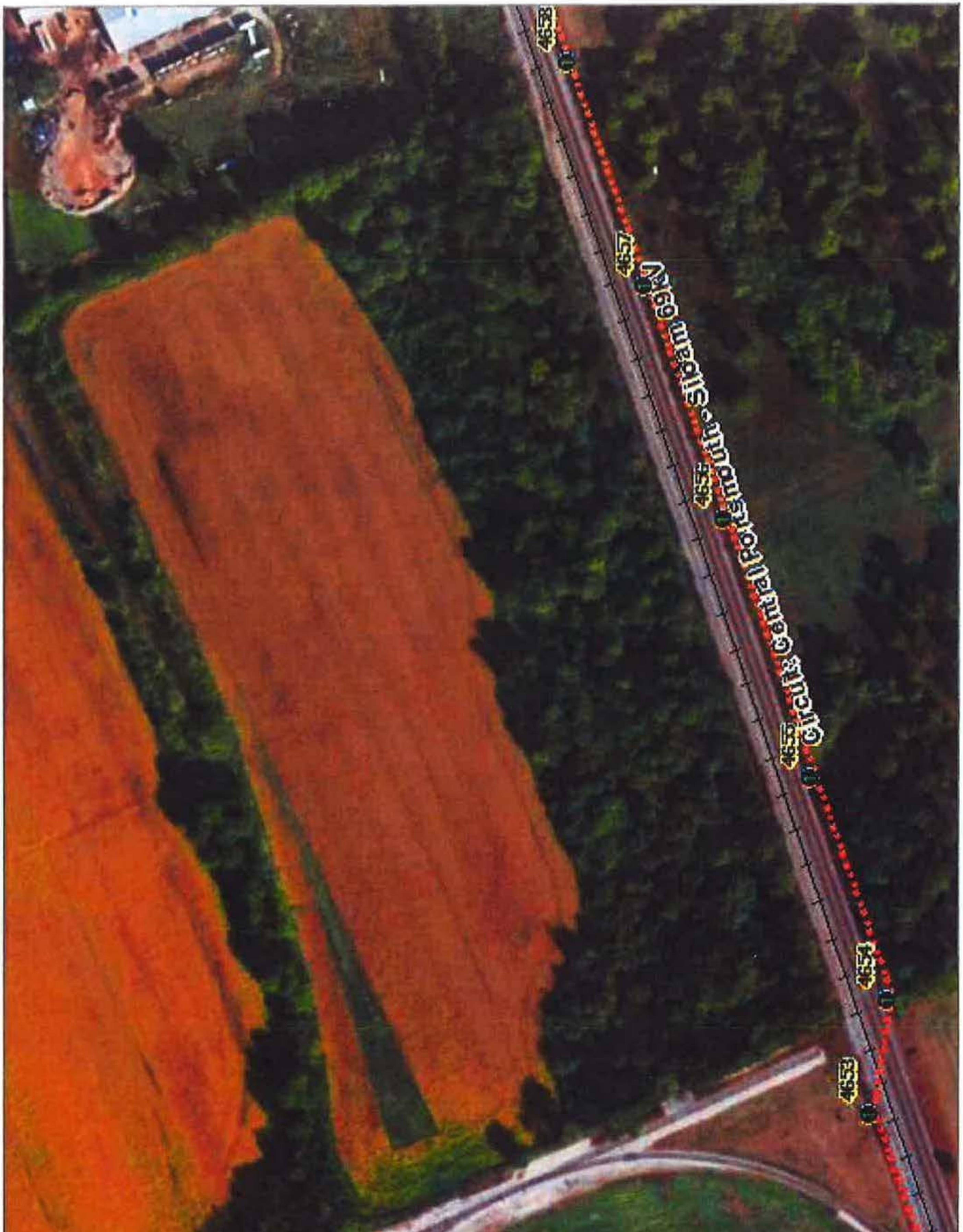
MIDDLETOWN COKE COMPANY
MIDDLETOWN, BUTLER COUNTY, OHIO

PRE-CONSTRUCTION ELECTRICAL
CONSTRUCTION POWER
SINGLE LINE – PLANT LAYOUT

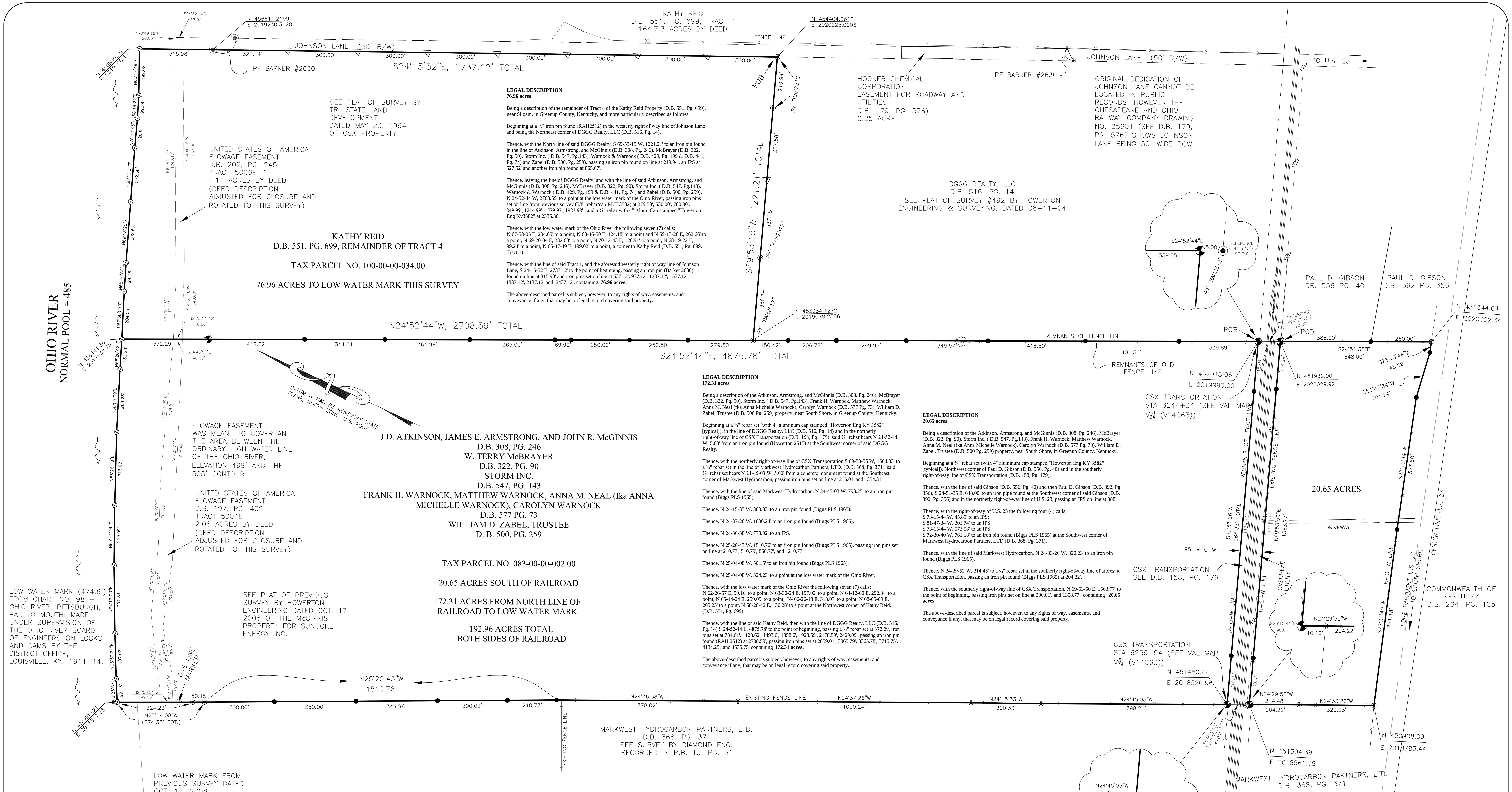
SIZE	DWG NO.	REV
D	MO-083-SE-002	2

SCALE NONE PROJECT NO. 14579 SHEET 1 OF 1


Circuit: Central Portsmouth - Siloam 69kV
Circuit: Argentum - Millbrook Park 138kV



4658
4657
Circuit: Central Portsmouth - Sibam 69kV
4656
4655
4654
4653



LEGAL DESCRIPTION
76.96 acres

Being a description of the remainder of Tract 4 of the Kathy Reid Property (D.B. 551, Pg. 699), near Siloam, in Greenup County, Kentucky, and more particularly described as follows:

Beginning at a ½" iron pin found (RAH2512) in the westerly right of way line of Johnson Lane and being the Northeast corner of DGGG Realty, LLC (D.B. 516, Pg. 14).

Thence, with the North line of said DGGG Realty, S 69-53-15 W, 1221.21' to an iron pin found in the line of Atkinson, Armstrong, and McGinnis (D.B. 308, Pg. 246), McBrayer (D.B. 322, Pg. 90), Storm Inc. (D.B. 547, Pg.143), Warnock & Warnock (D.B. 429, Pg. 199 & D.B. 441, Pg. 74) and Zabel (D.B. 500, Pg. 259), passing an iron pin found on line at 219.94', an IPS at 527.52' and another iron pin found at 865.07'.

Thence, leaving the line of DGGG Realty, and with the line of said Atkinson, Armstrong, and McGinnis (D.B. 308, Pg. 246), McBrayer (D.B. 322, Pg. 90), Storm Inc. (D.B. 547, Pg.143), Warnock & Warnock (D.B. 429, Pg. 199 & D.B. 441, Pg. 74) and Zabel (D.B. 500, Pg. 259), N 24-52-44 W, 2708.59' to a point at the low water mark of the Ohio River, passing iron pins set on line from previous survey (5/8" rebar/cap RLH 3582) at 279.50', 530.00', 780.00', 849.99', 1214.99', 1579.97', 1923.98', and a ¾" rebar with 4" Alum. Cap stamped "Howerton Eng Ky3582" at 2336.30.

Thence, with the low water mark of the Ohio River the following seven (7) calls:
N 67-58-05 E, 204.05' to a point, N 68-46-50 E, 124.18' to a point and N 69-13-28 E, 262.66' to a point, N 69-20-04 E, 232.68' to a point, N 70-12-43 E, 126.91' to a point, N 68-19-22 E, 99.24' to a point, N 65-47-49 E, 199.02' to a point, a corner to Kathy Reid (D.B. 551, Pg. 699, Tract 1).

Thence, with the line of said Tract 1, and the aforesaid westerly right of way line of Johnson Lane, S 24-15-52 E, 2737.12' to the point of beginning, passing an iron pin (Barker 2630) found on line at 315.98' and iron pins set on line at 637.12', 937.12', 1237.12', 1537.12', 1837.12', 2137.12' and 2437.12', containing **76.96 acres**.

The above-described parcel is subject, however, to any rights of way, easements, and conveyance if any, that may be on legal record covering said property.

LEGAL DESCRIPTION
172.31 acres

Being a description of the Atkinson, Armstrong, and McGinnis (D.B. 308, Pg. 246), McBrayer (D.B. 322, Pg. 90), Storm Inc. (D.B. 547, Pg.143), Frank H. Warnock, Matthew Warnock, Anna M. Neal (fka Anna Michelle Warnock), Carolyn Warnock (D.B. 577 Pg. 73), William D. Zabel, Trustee (D.B. 500 Pg. 259) property, near South Shore, in Greenup County, Kentucky.

Beginning at a ¾" rebar set (with 4" aluminum cap stamped "Howerton Eng KY 3582" [typical]), in the line of DGGG Realty, LLC (D.B. 516, Pg. 14) and in the northerly right-of-way line of CSX Transportation (D.B. 158, Pg. 179), said ¾" rebar bears N 24-52-44 W, 5.00' from an iron pin found (Howerton 2515) at the Southwest corner of said DGGG Realty.

Thence, with the northerly right-of-way line of CSX Transportation S 69-53-56 W, 1564.33' to a ¾" rebar set in the line of Markwest Hydrocarbon Partners, LTD. (D.B. 368, Pg. 371), said ¾" rebar set bears N 24-45-03 W, 5.00' from a concrete monument found at the Southeast corner of Markwest Hydrocarbon, passing iron pins set on line at 215.01' and 1354.31'.

Thence, with the line of said Markwest Hydrocarbon, N 24-45-03 W, 798.25' to an iron pin found (Biggs PLS 1965).

Thence, N 24-15-33 W, 300.33' to an iron pin found (Biggs PLS 1965).

Thence, N 24-37-26 W, 1000.24' to an iron pin found (Biggs PLS 1965).

Thence, N 24-36-38 W, 778.02' to an IPS.

Thence, N 25-20-43 W, 1510.76' to an iron pin found (Biggs PLS 1965), passing iron pins set on line at 210.77', 510.79', 860.77', and 1210.77'.

Thence, N 25-04-08 W, 50.15' to an iron pin found (Biggs PLS 1965).

Thence, N 25-04-08 W, 324.23' to a point at the low water mark of the Ohio River.

Thence, with the low water mark of the Ohio River the following seven (7) calls:
N 62-26-57 E, 99.16' to a point, N 63-30-24 E, 197.02' to a point, N 64-12-00 E, 292.34' to a point, N 65-44-24 E, 259.09' to a point, N- 66-26-18 E, 313.07' to a point, N 68-05-09 E, 269.23' to a point, N 68-20-42 E, 130.28' to a point at the Northwest corner of Kathy Reid, (D.B. 551, Pg. 699)

Thence, with the line of said Kathy Reid, then with the line of DGGG Realty, LLC (D.B. 516, Pg. 14) S 24-52-44 E, 4875.78' to the point of beginning, passing a ¾" rebar set at 372.29, iron pins set at 784.61', 1128.62', 1493.6', 1858.6', 1928.59', 2178.59', 2429.09', passing an iron pin found (RAH 2512) at 2708.59', passing iron pins set at 2859.01', 3065.79', 3365.78', 3715.75', 4134.25', and 4535.75' containing **172.31 acres**.

The above-described parcel is subject, however, to any rights of way, easements, and conveyance if any, that may be on legal record covering said property.

LEGAL DESCRIPTION
20.65 acres

Being a description of the Atkinson, Armstrong, and McGinnis (D.B. 308, Pg. 246), McBrayer (D.B. 322, Pg. 90), Storm Inc. (D.B. 547, Pg.143), Frank H. Warnock, Matthew Warnock, Anna M. Neal (fka Anna Michelle Warnock), Carolyn Warnock (D.B. 577 Pg. 73), William D. Zabel, Trustee (D.B. 500 Pg. 259) property, near South Shore, in Greenup County, Kentucky.

Beginning at a ¾" rebar set (with 4" aluminum cap stamped "Howerton Eng KY 3582" [typical]), Northwest corner of Paul D. Gibson (D.B. 556, Pg. 40) and in the southerly right-of-way line of CSX Transportation (D.B. 158, Pg. 179).

Thence, with the line of said Gibson (D.B. 556, Pg. 40) and then Paul D. Gibson (D.B. 392, Pg. 356), S 24-51-35 E, 648.00' to an iron pipe found at the Southwest corner of said Gibson (D.B. 392, Pg. 356) and in the northerly right-of-way line of U.S. 23, passing an IPS on line at 388'.

Thence, with the right-of-way of U.S. 23 the following four (4) calls:
S 73-15-44 W, 45.89' to an IPS;
S 81-47-34 W, 201.74' to an IPS;
S 73-15-44 W, 573.58' to an IPS;
S 72-30-40 W, 761.18' to an iron pin found (Biggs PLS 1965) at the Southwest corner of Markwest Hydrocarbon Partners, LTD (D.B. 368, Pg. 371).

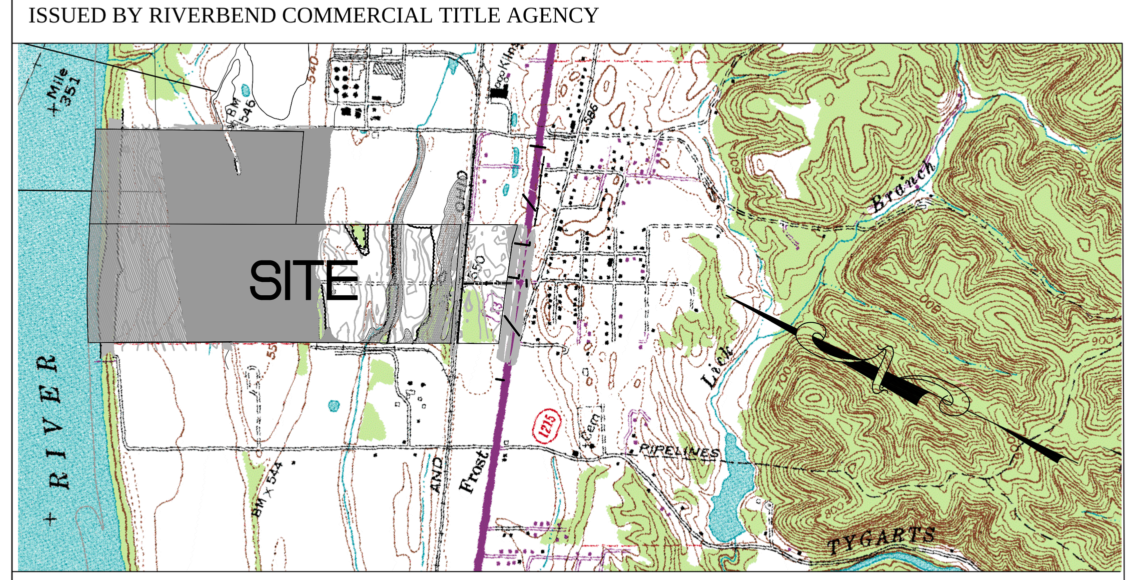
Thence, with the line of said Markwest Hydrocarbon, N 24-33-26 W, 320.23' to an iron pin found (Biggs PLS 1965).

Thence, N 24-29-52 W, 214.48' to a ¾" rebar set in the southerly right-of-way line of aforesaid CSX Transportation, passing an iron pin found (Biggs PLS 1965) at 204.22'.

Thence, with the southerly right-of-way line of CSX Transportation, N 69-53-50 E, 1563.77' to the point of beginning, passing iron pins set on line at 200.01', and 1358.77', containing **20.65 acres**.

The above-described parcel is subject, however, to any rights of way, easements, and conveyance if any, that may be on legal record covering said property.

TITLE COMMITMENT FA-KY00244 EFFECTIVE DATE MAY 14, 2012
TITLE COMMITMENT FA-KY00243 EFFECTIVE DATE MAY 23, 2012
FIRST AMERICAN TITLE INSURANCE COMPANY
ISSUED BY RIVERBEND COMMERCIAL TITLE AGENCY



VICINITY MAP (PORTSMOUTH QUAD) SCALE: 1"=2000' ±

SYMBOLS LEGEND

- (IPS) IRON PIN SET PREVIOUS SURVEY, 5/8" REBAR 30" LONG WITH PLASTIC CAP STAMPED "RLH KY 3582 OH 8280
- (IPS) IRON PIN SET, 1/2" REBAR 24" LONG WITH PLASTIC CAP STAMPED "RLH KY 3582
- (IPF) IRON PIN FOUND 5/8" REBAR–ALUM. CAP STAMPED DIA ENGR / BIGGS PLS 1965 (UNLESS NOTED)
- 1" IRON PIPE FOUND
- 3/4" REBAR WITH 4" ALUMINUM CAP STAMPED HOWERTON ENG KY3582
- CONC. MON. FOUND
- POINT NOT MONUMENTED
- TREE
- PROPERTY LINE
- FENCE LINE
- UTILITY POLE

SURVEYOR'S NOTES:

1. THE BEARINGS FOR THE SURVEY ARE REFERENCED TO MONUMENTS FOUND ALONG THE WESTERLY LINE OF JOHNSON LANE AND WERE ROTATED TO NAD83, KENTUCKY STATE PLANE, NORTH ZONE, U.S. FT.

2. THE SURVEYOR OF RECORD HAS REVIEWED THE TITLE COMMITMENT FA-KY-00244 PREPARED BY RIVERBEND COMMERCIAL TITLE AGENCY AND FIRST AMERICAN TITLE COMPANY, AND HAS DETERMINED THE FOLLOWING:

A) SHEDULE B, SECTION 2, ITEM 11, IS A FLOWAGE EASEMENT AND APPLIES TO THIS PROPERTY AS SHOWN ON PLAT.

3. THE SURVEYOR OF RECORD HAS REVIEWED THE TITLE COMMITMENT FA-KY-00243 PREPARED BY RIVERBEND COMMERCIAL TITLE AGENCY AND FIRST AMERICAN TITLE COMPANY, AND HAS DETERMINED THE FOLLOWING:

A) SHEDULE B, SECTION 2, ITEM 15, IS A FLOWAGE EASEMENT AND APPLIES TO THIS PROPERTY AS SHOWN ON PLAT.

B) SHEDULE B, SECTION 2, ITEMS 11 THRU 14 ARE ROAD AND UTILITY EASEMENTS ALONG U.S. 23 AND THE CSX RAILROAD AND DO NOT APPLY TO SUBJECT PROPERTY.

4. NO EVIDENCE OF OTHER EASEMENTS WAS OBSERVED, HOWEVER THE POSSIBILITY EXISTS THAT UTILITY EASEMENTS MAY ENCROACH INTO SUBJECT PROPERTY.

5. FLOODPLAIN DETERMINATION: A PORTION OF THE PROPERTY IS LOCATED IN FEMA ZONE AE AND ZONE X. REFER TO FIRM MAP: 21089C0056C, EFFECTIVE DATE SEPTEMBER 16, 2004. THE BASE FLOOD ELEVATION FROM THE FIRM MAP IS 537' (SEE SHEET 2 OF THIS SURVEY).

7. THE BOUNDARY CONTAINS A NATURAL WATER BOUNDARY AND IS SUBJECT TO CHANGE DUE TO NATURAL CAUSES AND IT MAY OR MAY NOT REPRESENT THE ACTUAL LOCATION OF THE LIMIT OF TITLE.

8. THERE ARE NO BUILDINGS EXISTING ON THE SURVEYED PROPERTY.

9. NO PLANNING OR ZONING EXISTS IN THIS UN-INCORPORATED AREA OF GREENUP COUNTY AT THIS TIME.

GPS CERTIFICATE

____THE CONTROL____________________ of this boundary survey was performed using GPS equipment; The accuracy and precision of all measurements made with that equipment meets all other accuracy and precision standards required otherwise by law or rules under Section 7(5) of the statutory requirements of the State of Kentucky. Type of GPS equipment used: manufacturer__HIPERLITE +__, model ____TOPCON_____, dual frequency receivers were used; Type of GPS survey that was performed: real time kinematic ("RTK") and network adjusted real time kinematic. Relative positional accuracy__X: 0.009(M) Y: 0.007 (M)________, vector closure_______N/A__________. Horizontal datum__SPC (1601 KY N)______, Vertical datum____NAVD88______, Geoid model ___GEOID09____

ALTA/ACSM Land Title Survey

To Sun Coke Energy Inc. Riverbend Commercial Title Agency and First American Title Insurance Company: This is to certify that this map or plat and the survey on which it is based were made in accordance with the 2011 Minimum Standard Detail Requirements for ALTA/ACSM Land Title Surveys, jointly established and adopted by ALTA and NSPS, and includes items 1, 3, 4, 5, 8, 11b, 13, 16, 18, & 21 of Table A thereof. The field work was completed on May 20th, 2013.

Richard L. Howerton, PLS 3582

SURVEYOR CERTIFICATE

In my opinion, this plat is a true and correct representation of the lands surveyed and has been prepared in conformity with the statutory requirements of the state of Kentucky.
This plat of survey is certified for and only for the parties whom this survey was performed. This certification does not extend to any unnamed successor or assignees of this property. Further certification of survey for successors and/or assignees of this property and/or plat requires signature and verification from the parties who performed this survey. The survey hereon is a(n) ☑ URBAN/ ☐ RURAL survey, and meets the specifications as outlined in the minimum standards survey requirements. Survey performed using Title Commitment from First American Title Insurance Company (FA-KY-00243 and FA-KY-00244). Surveyor does not certify title.

Name of Parties:	Certified by:	Date:
SUNCOKE ENERGY 11400 PARKSIDE DRIVE KNOXVILLE TN 37934		

THIS PLAT REPRESENTS AN URBAN BOUNDARY SURVEY AND COMPLIES WITH 201 KAR 18:150.

ALTA/ACSM SURVEY OF THE THE JOHN R. MCGINNIS ET-UX PROPERTY AND PART OF THE KATHY REID PROPERTY NEAR SOUTH SHORE, IN GREENUP COUNTY, KY. FOR SUNCOKE ENERGY, INC.

SunCoke Energy
11400 Parkside Drive
Knoxville TN 37934

HOWERTON ENGINEERING & SURVEYING PLLC
404-A MAIN STREET
GREENUP, KENTUCKY
(606) 473-5684
533 SECOND STREET
PORTSMOUTH, OH 45662
(740) 354-3684

BOUNDARY SURVEY

REVISIONS :
OCT. 8, 2013 – REVISED TO SHOW ORIGINAL LOW WATER MARK FROM MAP 98 FROM ARMY C.O.E. REV. BY SNS.
DEC. 12, 2014 – REVISED CHAIN OF TITLE OF TAX PARCEL NO.: 083-00-00-002.00, REV'D ADJOINER TO PAUL D. GIBSON

JOB #	DATE
310-015	DEC. 12, 2014
SCALE	PLAT #
1" = 200'	812
SHEET 1	OF 2