COMMONWEALTH OF KENTUCKY
ENVIRONMENTAL AND PUBLIC PROTECTION CABINET
FILE NO. DAQ-26003-037 and DAQ-26048-037

SIERRA CLUB, VALLEY WATCH, INC.,
LESLIE BARRAS, HILARY LAMBERT, and
ROGER BRUCKER,

PETITIONERS,

VS.

ENVIRONMENTAL AND PUBLIC PROTECTION CABINET,
and
THOROUGHBRED GENERATING COMPANY, LLC

RESPONDENTS.

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HEARING OFFICER'S REPORT AND RECOMMENDED SECRETARY'S ORDER

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I. EXECUTIVE SUMMARY

Nature of Case:

Challenges to TGC's Title V operating and PSD construction air quality permit V-02-001, and the permit's minor Revision #1, and Revision #2 for its coal burning electrical generating plant (TGS).

Appearances[1]:

Petitioners were represented by the Hon. Elizabeth Natter and the Hon. Robert Ukeiley. The Cabinet was represented by the Hon. Jack Bates, the Hon. Rick Bertelson, and the Hon. Susan Green. TGC was represented by the Hon. Harry Johnson III, the Hon. Kevin Finto, the Hon. Carolyn Brown, the Hon. Penny Shamblin, and the Hon. Eric Braun.

Hearing Officer:

Hon. Janet C. Thompson

Issues/Conclusions/Recommendations[2]:

As a result of the following conclusions, it is recommended that TGC's permit be **REMANDED to DAQ**.

Count 1 - Air Toxics, Risk

Issue - Whether DAQ failed to perform an adequate analysis under 401 KAR 63:020 to determine if TGS would emit hazardous substances in such quantities or duration as to be harmful to the health and welfare of humans, animals and plants.

Conclusion - DAQ erred by relying on the Cumulative Assessment to satisfy the requirements of 401 KAR 63:020, Section 3.

Recommendation - DAQ should be directed to evaluate the impact of TGS's potentially hazardous or toxic substances on animals.

Count 2 - Public Participation

Issue - Whether DAQ failed to make available to the public relevant information on which the permit determinations were based as required

[1] The Hon. Elizabeth Natter, co-counsel for Petitioners, and the Hon. Susan Green, co-counsel for the Cabinet, withdrew following the filing of post hearing briefs as a result of changes in their employment. The Hon. Jack Bates, another co-counsel for the Cabinet, withdrew on July 15, 2005, as a result of his retirement.

[2] The petition inadvertently did not list a Count 4, 5, 12 or 13. Count 15 was dismissed, and Count 16 simply challenges issuance of minor Revision #1, without presenting any claim as to the revision. My rulings on Counts 3, 6, and 7 are found in my Interim Report, Appendix 3 to this Report**.**

by 401 KAR 51:017[3], 401 KAR 52:100 and 40 CFR Section 51.161.

Conclusion - Petitioners failed to carry their burden of proof on most of the arguments they advance in Count 2, with the following exceptions**.**

Recommendations - The SOB should have included an explanation of why the permit's SCR control efficiency is less than that shown in a table in the SOB for SCRs. Also, the SOB should explain DAQ's reason for concluding that a dry ESP is equivalent to a baghouse or what the "clear technical concerns" are that justify the use of ESP controls. In addition, the SOB should discuss DAQ's evaluation of TGS's potentially hazardous or toxic substances on animals.

Count 3[4] - Increment/NAAQS

Issue - Whether DAQ erred by concluding that TGS will not cause or contribute to a violation of NAAQS (National Ambient Air Quality Standard) or increment and by accepting existing ambient air quality data.

Conclusion - Petitioners failed to establish a prima facie case as to Count 3.

Recommendation – Petitioners' request for relief should be denied.

Count 6 – Visibility – Mammoth Cave National Park

Issue - Whether DAQ erred by concluding that TGC will not adversely impact air quality related values, including visibility at Mammoth Cave National Park in violation of 401 KAR 51:017, Section 1(2), and whether DAQ improperly evaded FLAG (Federal Land Mangers' Air Quality Related Values Work Group) 2001 by prematurely deeming the application complete contrary to Section 1(13).

Conclusion – Petitioners failed to establish a prima facie case as to Count 6.

Recommendation – Petitioners' request for relief should be denied.

Count 7 – Coordination with Army Corps

Issue - Whether DAQ acted contrary to 401 KAR 51:017, Section 18, by failing to coordinate its review with the environmental review required of the Army Corps of Engineers by the National Environmental Policy Act (NEPA).

Conclusion - Petitioners failed to establish a prima facie case as to Count 7.

Recommendation – Petitioners' request for relief should be denied.

Count 8 - Additional Impact Analysis, Soils, Vegetation

Issue - Whether DAQ failed to require an adequate analysis of impairment to visibility, soils and vegetation as a result of emissions from TGS and associated growth in violation of 401 KAR 51:017, Section 14.

Conclusion – DAQ erred by determining that the Additional Impacts Analysis performed by TGC complies with 401 KAR 51:017, Section 14.

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[3] Effective July 14, 2004, 401 KAR 51:017 was amended. In this Report, I will cite to the version in effect at the time the permit was issued, 401 KAR 51:017 (2002).

[4] In an Interim Report (Docket #273, issued April 12, 2004), I granted TGC's motions for directed recommendation as to Counts 3, 6, and 7 on the basis that Petitioners failed to establish a prima facie case as to these counts. These counts are not further addressed in this Report, but are addressed in the Interim Report, which is Appendix 3**.**

Recommendation - TGC should be required to perform and submit an Additional Impacts Analysis in accord with the conclusions in the Hearing Officer's Report.

Count 9 - Best Available Control Technology

Issue - Whether DAQ's BACT determinations were arbitrary and capricious.

IGCC and CFB Determinations

Conclusion - DAQ erred as a matter of law by concluding that it lacked authority to require TGC to include IGCC and CFB in its BACT analysis.

Recommendation - DAQ should require TGC to do a BACT analysis on both IGCC and CFB.

Coal Washing Determinations

Conclusion - DAQ's rejection of coal washing is arbitrary and capricious because it is partly based on TGC's cost-effectiveness analysis, which is not supportable and understandable**.**

Recommendation - On remand, DAQ should direct TGC to provide a cost-effectiveness analysis for coal washing that includes consideration of both average and incremental cost effectiveness.

Clean Coals Determinations– Using a blend of lower sulfur coal as BACT

Conclusion - DAQ erred by failing to require TGC's SO_2 BACT analysis to include an evaluation of whether there are any economic, environmental or energy reasons why a lower BACT limit cannot be achieved by a blend of cleaner coals using the coal which TGS has available.

Recommendation – On remand, DAQ should direct that TGC's SO_2 BACT analysis include this evaluation.

BACT for NO_x Determinations

Conclusion - DAQ's determination to issue the permit with a NO_x limit of 0.08 lb/MMbtu was contrary to fact and law.

Recommendation - On remand, DAQ should make a new NO_x BACT determination.

BACT for PM or PM_{10}

Conclusion and Recommendation – This issue is moot because Revision #2 provides that the regulated particulate matter pollutant is "PM/PM_{10} (filterable and condensable)".

BACT for SO_2

Conclusion - DAQ's SO_2 BACT determination was erroneous because it was based on an inadequate analysis by TGC of the technical feasibility of meeting a limit of 99% reduction.

Recommendation - On remand, DAQ should make a new SO_2

BACT determination.

<u>BACT for Mercury and Beryllium</u>

Conclusion - It was erroneous for DAQ to make a BACT determination based on TGC's elimination of carbon injection and fabric filters without the required technical feasibility analysis.

Recommendation - On remand, DAQ should make a new BACT determination on mercury and beryllium.

Count 10 - Maximum Achievable Control Technology

Issue - Whether DAQ failed to perform proper case-by-case MACT analyses as to mercury and non-mercury hazardous air pollutants (HAPs).

Conclusion - Petitioners failed to carry their burden of proof to establish that DAQ's mercury MACT and non-mercury MACT determinations are erroneous or arbitrary.

Recommendation – Petitioners' request for relief should be denied.

Count 11 - Single Source

Issue - Whether DAQ erred by determining that the power plant and mine are separate sources, not a single source.

Conclusion - This issue is moot because of TGC's agreement that BACT will apply to both the emissions from the mine and the power plant.

Recommendation - TGC's agreement that BACT applies to both the emissions from the mine and the power plant should be incorporated in the permit.

Count 14 - Enforceability

Issue - Whether the permit conditions as written are enforceable as a practical matter, as required by 401 KAR 52:020.

Conclusion - The HAPs, VOC and PM limits are not enforceable.

Recommendations - On remand, DAQ should make a number of revisions, including the following:

For HAPs –

* The permit should indicate the primary method of determining compliance with HAPs limits.

* A HAPs coal test method, sampling procedure, and analysis procedure should be identified in the permit.

* The test method should be capable of measuring HAPs at levels below the permit limits.

* More than four analyses of coal samples should be required and should be recorded more frequently than quarterly.

* All control system operating parameters should be identified.

* The permit should state how monitoring provisions are to be used and whether exceedance of the operating parameter amounts to an exceedance of the HAPs limits.

For Monitoring –

In light of TGC's acknowledgement that Revision #2 addresses all of the issues Petitioners raise with regard to compliance provisions which appear only in the SOB, I conclude that the permit should be so revised to the extent any of the above compliance provisions appear only in the SOB and not in the permit.

For VOCs -

More frequent stack testing (not just an initial stack test) should be required to confirm the relationship between CO and VOCs and should be in the permit. The permit should also specify the test method. These requirements should also apply to the auxiliary boiler.

For PM -

1) The regulated pollutant should be corrected for the auxiliary boiler, as Revision #2, item #7, did for the PC boilers.

2) The permit should list test methods for PM/PM_{10} for the PC boilers and the auxiliary boiler. The test methods in the SOB need to be clarified so that the regulated pollutant is consistently identified.

3) Annual testing for the PC boilers is not adequate.

4) On remand, TGC should be required to present a test plan to develop the relationship between opacity and PM; to revisit the relationship if the fuel changes, equipment is updated or operating modes change; the 5% opacity fudge factor should be eliminated unless the maximum PM emission rate is substantially lower than the upper end of the opacity range; TGS should not be allowed to operate for extended periods of time at opacity levels that represent exceedance of the underlying PM limits; and periods of startup and shut down should not be exempted.

5) On remand, the location of the COMS should be changed as a result of testimony showing that COMS now allow accurate opacity measurements in wet stacks. 2-10-04 TE at 207:18-21; 2-11-04 TE at 117:2-5 (Fox).

6) PM control equipment operating parameters are inadequate for reasons cited by Petitioners. On remand, DAQ should reassess the parameters, and the permit should provide that an exceedance of the indicator range constitutes a PM violation.

For material handling units (units 4-9) –

Compliance with the monitoring and recordkeeping requirements of Title V Manual at pg. 6, Sec. 1b III and IV should be required.

Count 17 - Errors and Omissions

Issue – Whether there are errors and omissions in the permit and other documents which render the permit determinations arbitrary and capricious.

Conclusion - The permit contains numerous errors and omissions.

Recommendations –

Claims A, D, L, P, and W (second part) – DAQ should review.

Claim K – DAQ should clarify the inconsistency between the permit and the SOB.

Claim Q – DAQ should state in the SOB where it obtained Table 5.2.

Claim R – DAQ should state that the 24-hr increment is 4.98 μg/m^3.
Claim S – DAQ should correct typos in the SOB.

Count 18 - HAPs Emissions Estimates
Issue - Whether DAQ violated 401 KAR 52:020 by failing to provide a basis for the HAP emissions.
Conclusion - Petitioners failed to carry their burden of proof on Count 18.
Recommendation – Petitioners' request for relief should be denied.

Revisions #1 and #2
Issue – Whether DAQ erred by issuing Revisions #1 and #2.
Conclusion – Petitioners failed to carry their burden of proof on Revisions #1 and #2.
Recommendations – Revisions #1 and #2 should be affirmed**,** except for the changes which are necessary under the above Counts as a result of the remand of Title V/PSD Permit V-02-001.

II. STATEMENT OF THE CASE

In these consolidated cases, Petitioners[5] (the Sierra Club, Valley Watch, Inc., Leslie Barras, Hilary Lambert and Roger Brucker) challenge a Title V operating and PSD (Prevention of Significant Deterioration) construction air quality permit V-02-001, minor permit Revision #1, and Revision #2 issued by the Cabinet's Division for Air Quality (DAQ) to Thoroughbred Generating Company (TGC) for the construction and operation of a 1,500 megawatt (MW) pulverized coal-fired electric generating facility in Muhlenberg County, near Central City, Kentucky. The Title V/PSD permit was issued on October 11, 2002; minor Revision #1 was issued on December 6, 2002; and Revision #2 was issued on February 17, 2005.[6]

[5] In their post hearing brief, Petitioners include an appendix on the issue of standing and cite to evidence which satisfies the standing requirement for each individual petitioner. Petitioners note that Respondents did not challenge Petitioners' standing to contest the TGC permit and Revisions #1 and #2. Although this issue was not raised prior to the post hearing brief, I conclude that Petitioners amply demonstrated their standing.
[6] File No. DAQ-26003-037 represents Petitioners' challenge to the original permit. File No. DAQ-26048-037 represents Petitioners' challenge to minor Revision #1. These files were consolidated by agreement. Revision #2 was issued on February 17, 2005, following the close of the formal hearing. However, by Agreed Order, entered on April 19, 2005, the parties are in agreement that the claims raised by Petitioners in their petition challenging Revision #2 shall be considered as part of File Nos. DAQ-26003-037 and DAQ-26048-037. A copy of Revision #2 and the accompanying Statement of Basis (SOB) is included with the Agreed Order, Docket #339.

The combustion of coal to produce electricity generates air emissions of pollutants including nitrogen oxide (NO_x), sulfur dioxide (SO_2), carbon monoxide (CO), volatile organic compounds (VOC), acid gases, and metals. According to the U.S. EPA, this project represents one of the largest emission sources proposed in all of Region 4 in many years and is the first major coal-fired power plant to be constructed in Kentucky in nearly 20 years. As such, the TGC permit was described as a "very high visibility permit". The facility will be located approximately 46 miles west/northwest of Mammoth Cave National Park (the Park) and approximately 37 miles from the Indiana border. The proposed plant sits to the southeast of the Green River.

In Kentucky, the pre-construction (Title I) and operating (Title V) permits are combined into one Title V permit containing all applicable requirements for a facility. A source with the potential to emit (PTE) above the 100 tons per year threshold in one of the 28 named categories, including electric steam generating units with a heat input of greater than 250 million BTU[7] per hour, for any of the six criteria pollutants (sulfur dioxide (SO_2), particulate matter (PM), nitrogen oxides (NO_x), carbon monoxide (CO), ozone, and lead) is considered a major source for Title V and PSD permitting purposes.

At the time a revised permit application was filed in October 2001, TGC projected that the source, which is to be named Thoroughbred Generating Station (TGS), would begin operating in 2006 and would be capable of supplying electricity for 1.5 million households. Construction is projected to take four years and had not begun at the time of the formal hearing in this case.

[7] British thermal unit

TGC is owned by Peabody Coal Company, the largest coal company in the world. The facility, which will be built on 2,700 acres of formerly mined lands, will burn high sulfur coal from seams Nos. 8 and 9 of a new nearby underground mine, also owned by Peabody. The mine will be permitted separately from TGS. Because the coal will come from the nearby mine, the power plant is referred to as a mine-mouth facility. The electricity can be sold within or outside of Kentucky. The mine plan for TGS is for 34 years. The life of the power plant is projected to be 40 years.

The proposed TGS plant will consist of two 7,443 MMbtu[8]/hour pulverized coal (PC) boilers, which operate with a total nominal output capacity of 1,500 MW (i.e. 750 MW each). The boilers will turn turbines, which in turn, rotate generators to produce electricity. Related facilities at the plant include an auxiliary boiler, cooling towers, oil storage facilities, emergency generator, two diesel and one electric powered fire pumps, facilities for handling flue gas desulfurization reagent and by-product, and ash and coal transfer equipment.

During the 18-month permit review process, which began when the original application was filed in early 2001, comments and input were received from numerous groups in addition to Petitioners, including the American Lung Association, the National Parks Conservation

[8] MMbtu means a unit of heat equal to one million British thermal units.

Association, the Natural Resources Defense Council (NRDC) and the Owensboro Building and Trade Council. In addition, several federal agencies, including the U.S. EPA, the National Park Service (NPS) and the U.S. Fish and Wildlife Service (USFWS) were extensively involved in the permit process. Because of the proximity of the facility to Mammoth Cave National Park (the Park), the NPS has a responsibility under the Clean Air Act (CAA) to review the permit in accordance with its mandate to protect visibility and other air quality related values at the Park, a Class I air quality area administered by the NPS, from the adverse impacts of air pollution. The nearest park boundary is approximately 46 miles east-southeast from the proposed facility. The U.S. EPA also has a responsibility to review the permit under the CAA. States are required to submit each proposed Title V permit to EPA for review. Upon receipt of a proposed permit, EPA has 45 days to object to final issuance of the permit if it is determined not to be in compliance with applicable requirements or the requirements of Title V. Other governmental agencies which commented on the permit include the Evansville Environmental Protection Agency, Jefferson County Air Pollution Control District, and the Indiana Department for Environmental Protection Management (IDEM). IDEM's involvement stems from the fact that the plant will be located only 37 miles from the Indiana border. Because of the potential impact on air quality in Indiana and the concern for consistency across the country in the issuance of PSD permits, IDEM was an active commenter on the permit.

Petitioners' case at the time of the formal hearing contained 12 counts[9]. However, the majority of the formal hearing was devoted to Counts 9 (BACT- Best Available Control Technology) and 10 (MACT – Maximum Achievable Control Technology). In Count 9,

[9] The petition inadvertently did not list a Count 4, 5, 12 or 13. Count 15 was dismissed, and Count 16 simply challenges issuance of minor Revision #1, without presenting any claim as to the revision.

Petitioners allege that the Cabinet's determinations of BACT emission limits are contrary to fact and law. In Count 10, Petitioners allege that the Cabinet's case-by-case MACT determinations were inadequate. Petitioners urge that the permit be revoked and remanded to DAQ. On the other hand, Respondents urge that the BACT and MACT limits in the permit are appropriate and even represent some of the most stringent limits of any PSD permit for a pulverized coal power plant at the time the permit was issued.

The Cabinet states that this is "the largest case in the Cabinet's 30-plus year history, and has produced a record commensurate with that distinction." The formal administrative hearing was lengthy, and the testimony and exhibits from expert witnesses are complex. The hearing was held at the Capital Plaza Tower in Frankfort. It began on November 3, 2003, and concluded on June 16, 2004, with a total of some 73 days of testimony by 25 witnesses and introduction of some 600 exhibits (approximately 450 were introduced by Petitioners, 115 by TGC, and 35 by the Cabinet). In addition, over 60 joint exhibits were admitted, related to the permitting process. The exhibits are identified as follows: P (Petitioners' exhibit); Cab (Cabinet's exhibit); TGC (Thoroughbred Generating Company's exhibit); PD, TGCD and CabD are the parties' demonstrative exhibits; PR, CabR, and TGCR are the parties' rebuttal exhibits; PAR (Petitioners' exhibit which was initially admitted as avowal only, but during rebuttal was changed from avowal to admitted); exhibits which contain confidential business information are identified by CBI, preceded by the party offering the exhibit. A "KEC" Bates stamp on an exhibit indicates that TGC produced this item during discovery out of the files of Kentuckiana Engineering Company (KEC), the permitting contractor for the project. A "TB" stamp indicates that TGC produced this item out of its Bates' files.

Closing arguments were held on June 24, 2004. During the hearing, the presentation of exhibits was provided both in written form and at the same time the exhibits were produced for viewing on a large screen and on individual monitors stationed throughout the hearing room. An expedited transcript of each day's testimony was produced to all parties by the court reporter during the evening following conclusion of that day's testimony. The volumes of final transcript were filed in the Office of Administrative Hearings at the time they were completed, with the final day's transcript filed on June 17, 2004, the day following the last day of the formal hearing. The transcripts[10] of the formal hearing total some 12,000 pages.

In deciding on the admissibility of exhibits, I disallowed exhibits when the information presented in the exhibit was not available to DAQ prior to the date of the permit's issuance, October 11, 2002. My reasoning was that if the information was not available to DAQ prior to October 11, 2002, it was not relevant to determinations relating to the permit. Upon my determination that these exhibits would not be admissible, they were accepted by avowal only. However, when the parties' cases in chief were concluded, and rebuttal began, exhibits relating to information postdating October 11, 2002, were admissible as being relevant if they tended to show that DAQ's permit decisions were either erroneous or arbitrary, or conversely, if they tended to show that DAQ's permit decisions were neither erroneous nor arbitrary. Therefore, during rebuttal, some exhibits which were admitted earlier only by avowal were changed to reflect that they are now admitted during rebuttal.

Prior to the formal hearing, motions were made in an attempt to narrow the issues which would remain for decision following the hearing. TGC's motion for partial dismissal of Counts

[10] Cites to the transcripts of evidence are often to the date, page and to the specific lines, i.e. 4-15-04 TE 8:3 – 9:20 (Adams).

1, 6, 7, 9, 10, 14 and 15 (in which the Cabinet joined except as to Count 1) was denied. Docket #42. Motions for summary disposition were made by one or more of the parties as to each of the Counts. All motions for summary disposition were denied. Docket #194.

During the course of the formal hearing, additional motions were filed to narrow and to clarify certain issues. My rulings on these motions are as follows:

1. Order Granting TGC's Motion to Exclude Irrelevant Evidence Regarding Revised National Ambient Air Quality Standards (NAAQS) (Docket #257, issued March 3, 2004).

This order provides that EPA's 1997 revision of the NAAQS – adopting the 8-hour ozone and $PM_{2.5}$ standards - cannot be the basis for revoking or remanding this permit because the revised standards have not been adopted as regulations or incorporated by reference into Kentucky law.

2. Order Granting TGC's Motion for a Ruling That the Draft October 1990 New Source Review (NSR) Workshop Manual is Not Binding on DAQ, But Denying Request to Exclude Evidence Pertaining to the Manual; and Granting TGC's Motion to Exclude Evidence Regarding Modeling of Mobile Sources. (Docket #249, issued February 18, 2004)

This order reflects that there is no disagreement among the parties that the NSR Manual is not a binding legal requirement on DAQ because it has not been incorporated into the regulations. As also acknowledged by the parties, it is relevant guidance information and as such is appropriate for use by DAQ.

With regard to mobile sources, the order states that emissions from a mobile source (tailpipe of a motor vehicle, from a train, or from a vessel) are specifically excluded as part of NAAQS or PSD increment compliance demonstration.

In addition, following Petitioners' case in chief, TGC filed Motions for Directed Recommendation as to Counts 3, 6, 7, 8 and 11. Pursuant to 400 KAR 1:090 Section 12, in considering a motion for directed recommendation, the hearing officer shall consider all of the evidence presented at the hearing by the nonmoving party (Petitioners) and shall draw all inferences in favor of the nonmoving party. Following consideration of the motions, responses and replies, I issued an Interim Report Granting TGC's Motions for Directed Recommendation as to Counts 3, 6 and 7 and Denying TGC's Motions for Directed Recommendation as to Counts 8 and 11. (Docket #273, issued April 12, 2004, and Appendix 3 to this Report). This Interim Report found that Petitioners failed to establish a prima facie case as to Count 3 (Increment/NAAQS), Count 6 (Visibility – Mammoth Cave) and Count 7 (Coordination with Army Corps of Engineers). Thus, I am recommending to the Secretary that Petitioners' request for relief on Counts 3, 6 and 7 be denied.

This Report contains the following five appendices:

1. Glossory of abbreviations and acronyms.
2. List of individual exhibits, both admitted and avowal, and list of joint exhibits.
3. Interim Hearing Officer's Report and Recommendation
4. Permit V-02-001 (Jt. #6)
   Updated Statement of Basis (SOB) (Jt. #7)
   Revision #1 (Jt. #8)
   Revision #2 and SOB (Docket #339)
5. Count 17 table

Following the conclusion of the formal hearing, the parties submitted post hearing briefs, tendered Hearing Officer Reports and Recommended Orders, and appendices of supporting authorities. The post hearing briefing began with the filing of Petitioners' brief, which was followed by responsive briefs filed by TGC and the Cabinet, and a reply brief filed by Petitioners. The post hearing briefing was concluded on December 20, 2004. The post hearing briefs and appendices of supporting authorities fill some 15 large notebooks, and total thousands of pages[11]. The record of the case, including filings prior to the formal hearing, transcripts, exhibits, and post hearing filings, fills some 30 banker's boxes.

Following the conclusion of the formal hearing, this Office received copies of the following submittals to DAQ:

> On July 1, 2004, TGC filed a list of 12 proposed administrative and/or minor permit amendments with DAQ[12]. Docket #299.
>
> On July 30, 2004, Petitioners sent a letter to DAQ in which they supported certain proposed revisions and opposed others. Docket #300.
>
> On August 12, 2004, DAQ received a letter from TGC replying to Petitioners' letter. Docket #308.

The Cabinet stated in its post hearing brief that TGC's proposed amendments were under review by DAQ, but no determination had been made. However, on February 17, 2005, the Cabinet issued Revision #2 in response to TGC's proposed permit amendments. On March 21, 2005, Petitioners filed a petition to contest Revision #2. (Docket #332). They urged that their petition be considered as part of this pending case without further proof.

By agreement of the parties, the claims raised by Petitioners in their latest petition shall be considered as part of File Nos. DAQ-26003-037 and DAQ-26048-037. A copy of Revision #2 and the accompanying Statement of Basis (SOB) is included with the Agreed Order, entered on April 19, 2005. (Docket # 339).

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[11] Petitioners' initial post hearing brief is 121 pages. The Cabinet's post hearing response brief is 178 pages. TGC's response brief is 281 pages. Petitioners' reply brief is 723 pages (this is not a typo!).

[12] TGC announced at the conclusion of the formal hearing that it was filing a permit revision with DAQ.

Based on the following Findings of Fact and Conclusions of Law, I recommend that TGC's permit be REMANDED to DAQ, and that DAQ be DIRECTED to comply with the recommendations specified in the Secretary's Final Order.

III. BURDEN OF PROOF

Pursuant to 401 KAR 100:010 Section 13(9), Petitioners have the burden of going forward to establish a prima facie case and the ultimate burden of persuasion as to the requested relief.

My report shall be based on a preponderance of the evidence appearing in the record as a whole. 401 KAR 100:010 Section 3(5).

IV. SUMMARY OF THE EVIDENCE

Testimony

Petitioners' Witnesses Called in their Case in Chief[13] :

Leslie Barras, a Petitioner, holds a law degree and two master's degrees. She is currently associate director and staff attorney for a land and river conservancy organization in Louisville. She and her husband are leaders of a program called the Inner City Kid Outing Program which is sponsored by the Sierra Club's Greater Louisville Group which takes inner city children on outings, including to Mammoth Cave.

Roger Brucker, a Petitioner, is an adjunct professor in the department of geography and geology at Western Kentucky University, where he teaches a course in speleology, which is the

[13] Petitioner Hilary Lambert did not testify at the formal hearing. The Petition states that Dr. Hilary Lambert is a resident of Fayette County and a member of the Cumberland Chapter of the Sierra Club and conservation co-chair of the Chapter's Bluegrass Group. She has hiked and participated in Mammoth Cave National Park tours.

Petitioners' counsel state that none of their witnesses were paid for testifying. They all either provided their testimony on a pro bono basis or pursuant to a subpoena.

general science of caves. He has authored or co-authored four books on Mammoth Cave and has written a number of scientific papers about the cave. Brucker is a frequent visitor to Mammoth Cave and takes his speleology students to the Park. Since first visiting the Park in 1937, he estimates that he has visited the park some 1,000 times.

John Blair is the president and administrator of Valley Watch, Inc., a Petitioner, and an organization whose primary mission is to protect the public health and environment of the Lower Ohio Valley. He is an aerial photographer who is concerned about the effects of air pollution on his photography, as well as on his health and recreational activities on the Green River. He lives some 45 miles from the proposed TGS site.

Ramesh Bhatt is vice chair of the Kentucky Chapter of the Sierra Club. He is a professor of psychology at the University of Kentucky.

Janet McCabe is the assistant commissioner for the Office of Air Quality, Indiana Department of Environmental Management (IDEM). (Video deposition and written transcript).

Nisha Sizemore, an environmental engineer, is a technical environmental specialist in the Permits Branch of IDEM's Office of Air Quality. She reviews all PSD permits written in the Permits Branch and serves as a technical resource and mentor for permit writers. Prior to her present position, which she assumed in 2002, she wrote PSD permits. Sizemore drafted the comments on the TGC permit, which was assigned to her for review. (Video deposition and written transcript).

Thomas Poulson, who holds a Ph.D. in zoology with a minor in botany, retired in 2000 from a teaching position at the University of Chicago where he taught ecology and evolution. Prior to teaching at the University of Chicago, he taught in the biological sciences departments at Yale and also at Notre Dame. He currently lives in Florida, where he teaches various ecology courses. During the early 1990s, he was a consulting ecologist at Mammoth Cave for three summers and was involved in designing a long-term ecological monitoring program at the Park. Dr. Poulson was recognized as an expert in cave biology.

Christopher Groves has a Ph.D. in environmental science with a concentration in geology. He is a professor in the geography and geology department at Western Kentucky University. He serves as co-director of a United Nations scientific effort called Global Correlation of Karst to Geology and Relevant Ecosystems, part of UNESCO's international geological program. He was recognized as an expert in hydrogeology and karst systems.

Phyllis Fox has master's and doctorate degrees from the University of California at Berkeley. She is a registered professional environmental engineer in Arizona and Washington, a chemical engineer in California, and a registered engineer in Georgia and Florida. Fox has some 32 years of experience in environmental engineering, including working on the design of power plants, managing research programs on various energy processes, and developing and employing emission monitoring techniques. Since 1981, she has worked as a consulting engineer with her own business in California, working in several major areas – air pollution control and air quality impact analysis, water pollution control, water impact analysis and hazardous waste. More specifically, she has been involved in preparing and reviewing hundreds of BACT analyses on a wide range of pollution control systems that involve NO_x, SO_2, PM_{10} and trace metals. She estimated that roughly half of her work is for industry clients, while the other half is for governmental clients. Fox has worked in the following states: California, Oregon, Washington, Arizona, Oklahoma, Colorado, Montana, Illinois, Indiana, Michigan, Ohio, Connecticut, New Jersey, Massachusetts, Georgia, Florida, Hawaii and Alaska. Fox was recognized as an expert in air permitting and in the review of air permit applications as they relate to BACT and MACT.

William Powers has a B.S. degree in mechanical engineering and a master's degree in public health and environmental science. He has worked in the field of air permitting in relation to power plants for approximately 20 years. For the past nine years, he has worked for his own consulting firm, Powers Engineering in San Diego, CA, which is involved in emissions testing, BACT analyses, and control technology assessments of all types, primarily related to air pollution. He co-authored two Electric Power Research Institute (EPRI) documents in 2000 and 2001 on permitting gas turban power plants, and in both of the documents, the evaluation involved the study of how to do a BACT analysis. EPRI is the research arm of the electric utility industry in the U.S. He was qualified as an expert in the field of environmental engineering and air pollution control technology.

Christine Shaver is chief of the Air Resources Division for the NPS located in Denver. (Deposition read into record; written transcript)

Joe Scire is a vice president and the manager of Earth Tech's Atmospheric Studies Group. He has over 20 years' experience in the design, development, and application of research and regulatory air quality models. He holds an M.S. (meteorology) and B.S. (earth and planetary science) from the Massachusetts Institute of Technology. He played a major role in the development of several widely-used models including the CALPUFF modeling system, which is used in Class 1 air modeling and which EPA approved as a guideline model. As a guideline model, it appears in Appendix W to 40 CFR Part 51. At the time of his testimony in this case, he had done three Class I increment analyses for coal-fired power plants.

Dianna Tickner is president of TGC and vice president of generation development for Peabody Energy. She is the project manager for the TGC project and is responsible for all the engineering design, permitting and general project management. Tickner has a B.S. in mining engineering and an M.B.A. Tickner has worked in the mining industry for over 20 years. She was recognized as an expert in coal mining and coal quality and as an expert with respect to coal washing costs.

Bryan Handy is a consultant with Kentuckiana Engineering Company, Inc. (KEC), the permitting contractor for the project. He received a BS degree in chemical engineering and an M.B.A. from the University of Louisville. He is not a registered professional engineer. Handy was employed in DAQ's Permit Review Branch, Combustion Section, immediately prior to his employment with KEC, which began in the fall of 2000. He was recognized as an expert on air modeling in Kentucky, emissions estimates for TGS, and on BACT and MACT analyses and requirements. Handy estimated that he worked on about 10 PSD applications with BACT analyses while he was employed with DAQ and about 10 since his employment with KEC, not all were on coal-fired power plants.

Donald Shepherd is an environmental engineer with the Air Resources Division of the NPS, in its Denver, CO office. His primary responsibility is to evaluate air pollution control technology in the Policy, Planning and Permit Review Branch. His experience includes 29 years in the field of air pollution control and air permitting and 26 years involved in making and/or reviewing BACT determinations. (Video deposition and written transcript)

Rick Olson is an ecologist in the Division for Science and Resources Management at the Park. He prepared one of three briefing papers, or literature searches, on the effects of the permit on threatened and endangered species. His paper focused on the ramification of increased acid deposition. (video deposition and written deposition transcript)

Robert Carson is an air resources management specialist in the Division for Science and Resources Management at the Park. He prepared one of three briefing papers, or literature searches, on the effects of the permit on threatened and endangered species. His paper looked at existing ozone data to see the kind of impacts which could potentially be incurred by additional ozone levels. (video deposition and written deposition transcript)

Kurt Helf is an invertebrate ecologist in the Division for Science and Resources Management at the Park. He prepared one of three briefing papers, or literature searches, on the effects of the permit on threatened and endangered species. His paper focused on mercury toxicity and contamination. In his paper, Helf states that prevailing winds in the area of the Park tend to blow northeast. (written deposition transcript)

Mark DePoy is chief of the Division for Science and Resources Management at the Park. (Written deposition transcript)

Steve Alexander is an ecologist with the USFWS. (written deposition transcript)

Stuart Ecton is an environmental scientist II with DAQ's Program Planning and Administrative Branch, whose primary responsibility is computer modeling. He has served in this position for about three years and has been in the Permit Review Branch for 15 years.

Tom Adams, a registered professional engineer, is a senior environmental engineering consultant with DAQ's Permit Review Branch. He has a B.S. degree in chemical engineering from the University of Kentucky and a master's degree in engineering with a biomedical emphasis from the University of Houston. Adams served as the environmental engineering consultant for the TGC permit. As one of two environmental engineer consultants for DAQ Permit Review Branch, he reviews air quality permits, monitoring them for consistency, uniformity, and compliance with regulations. He has held this position for three years and has worked for DAQ since 1992. Adams was recognized as an expert in the field of air quality permitting.

Dwain Kinkaid is a consultant with KEC.

Albert Westerman is branch manager of the Risk Assessment Branch of the Cabinet's Division of Environmental Services. He received his B.S. and M.S. degrees in zoology from the University of Kentucky and his Ph.D. in biology with a specialty in toxicology from the University of Kentucky. Dr. Westerman supervised the work of Larry Taylor who assisted with the Cabinet's evaluation of proposed power plants that culminated in preparation of the Cumulative Assessment. Dr. Westerman began his employment with the Cabinet in 1985 as part of the bioassay program in the Division of Water, and in 1990, he began setting up the risk assessment program for Kentucky. He has 33 years of study and experience in environmental evaluation, environmental toxicology and risk assessment. He was recognized as an expert on biology and risk assessment.

Larry Taylor is an environmental scientist IV with the Department for Environmental Protection where he serves as the science advisor to the Commissioner of the Department of Environmental Protection. He received his B.S. and M.S. in biology from the University of Kentucky and has had extensive training in risk assessment. He was recognized as an expert in the field of risk assessment.

Ben Markin is an environmental control supervisor in DAQ's Permitting Branch, a position he has held since February 2003. He has a B.S. degree in chemical engineering and an M.S. degree in public administration. Markin took over as the permit writer on the TGS project in 2001.

Donald Newell received his B.S. degree in mechanical engineering from Purdue University and his M.S. in management. He is currently branch manager of DAQ's Permitting Branch, a position he had held for about a year and a half at the time of the formal hearing. Prior to this position, he was manager of DAQ's Field Operations Branch, and before that he was supervisor of the Combustion Section in Permit Review. When he joined DAQ in 1999, he initially was in the Permitting Branch. He was recognized as an expert in Kentucky's air quality permitting program.

Cabinet's Witnesses Called in its Case in Chief:

Diana Andrews has served as assistant director of DAQ since 1993, and she has been employed by DAQ or its predecessor agencies for approximately 36 years. As the assistant director, she performs the final review of air quality permits. She has a B.S. degree in chemistry from the University of Louisville. Andrews was recognized as an expert on Kentucky's air quality program.

Albert Westerman – see above

Stuart Ecton – see above

Larry Taylor – see above

Ben Markin – see above

Donald Newell – see above

Tom Adams – see above

TGC's Witnesses Called in its Case in Chief:

Dianna Tickner - see above

Tom Lillestolen is a registered engineer and is the current director of Global Technology at ALSTOM Power, Inc.'s Power Environmental Systems Division, in Knoxville, TN. He has a B.S. degree in chemical engineering with more than 30 years' experience related to gas emission control technologies. Lillestolen was recognized as an expert in air pollution control equipment, design and evaluation.

J. Edward Cichanowicz is an independent consultant from Saratoga, CA, who specializes in pollution control technology and multiple pollutant strategies. He received his B.S. degree in mechanical engineering from Clarkson University and his M.S. in mechanical engineering and thermal sciences from the University of California at Berkeley. He subsequently worked for EPA and the Electric Power Research Institute (EPRI). He was recognized as an expert in air emission control equipment performance evaluation.

Bryan Handy – see above

John Notar is a meteorologist with NPS, Air Resources Division, Policy, Planning and Permit Review Branch. His duties include conducting and reviewing air dispersion modeling for proposed PSD permits. He has held his current position for 12 years, and previously for 11 years worked with US EPA Region 8, in Denver. He did a review to determine the increment consumed by TGS, the acid deposition of total sulfur and total nitrogen to the Park from TGS, and the visibility impacts from the proposed plant, and also a cumulative SO_2 Class I increment analysis, including TGS and other SO_2 increment-consuming sources in the area. (Video deposition and written transcript)

Rebuttal Witness Called by Petitioners

Phyllis Fox

Sur-rebuttal Witnesses Called by the Cabinet

Tom Adams and Albert Westerman

Reply to Sur-rebuttal Witness Called by Petitioners

Phyllis Fox

V. GENERAL FINDINGS OF FACT

Having heard the testimony offered, and having reviewed the entire record and the exhibits contained therein, I find, by a preponderance of the evidence, the following facts:

The Parties

1. The Cabinet's Division for Air Quality (DAQ) has the statutory duty of issuing air quality permits which are in compliance with the federal Clean Air Act (CAA) program and Kentucky's State Implementation Plan (SIP).

2. Petitioner Sierra Club is a non-profit corporation with more than 700,000 members nationwide and more than 4,000 members in Kentucky. The Club has been involved in Clean Air Act issues since the Act came into being in the 1970s.

3. Petitioner Valley Watch is also a non-profit corporation with a mission of protecting the public health and environment of the Lower Ohio Valley. Its members are concerned about the additional pollution which TGS will bring to a region that has health problems due to air quality issues.

4. Individual Petitioners Leslie Barras and Roger Brucker share concerns about how the proposed facility will impact the Park.

5. Barras' concern about the TGS facility stems from her volunteer work with disadvantaged youth whom she and her husband take on trips to the Park and with how the facility might impact air in Louisville, where she lives. She is also concerned that political influence affected the NPS's decision to withdraw its initial finding that emissions from TGS would cause an adverse impact on the Park.

6. Brucker has devoted a significant portion of his professional life to teaching and writing about Mammoth Cave. He has concerns about impaired visibility and damage to vegetation in the Park from air pollution from the facility.

7. Respondent Thoroughbred Generating Company, LLC, the permittee, is a wholly owned subsidiary of Peabody Energy Company, the largest coal company in the world.

Description of the Project

8. In Kentucky, the pre-construction (Title I) and operating (Title V) permits are combined into one Title V permit containing all applicable requirements for a facility. A source with the potential to emit (PTE) above the 100 tons per year threshold in one of the 28 named categories, including electric steam generating units with a heat input of greater than 250 MMbtu per hour, for any of the six criteria pollutants (sulfur dioxide (SO_2), particulate matter (PM), nitrogen oxides (NO_x), carbon monoxide (CO), ozone, and lead) is considered a major source for Title V and PSD permitting purposes.

9. TGS will consist of two 7,443 MMbtu/hour pulverized coal boilers, which will operate with a total nominal output capacity of 1,500 MW (*i.e.*, 750 MW each). Jt. #7 at 4; Jt. #57 at Red 11.[14] The pulverized coal boilers will be tangentially fired, dry bottom units. Steam generated in the boilers will be used to turn turbines, which turn generators to produce electricity. The plant is permitted to operate 8,760 hours per year (24 hours a day x 365 days a year) for each unit. Jt. #7 at 4; Jt. #57 at Red 23.

10. TGS will also have an auxiliary boiler, cooling towers, oil storage facilities, emergency generator, two diesel and one electric powered fire pumps, facilities for handling flue gas desulfurization reagent and by-product, and ash and coal transfer equipment. Jt. #7 at 4; Jt. #57 at Red 12.

[14] During the formal hearing, page numbers were manually added in red ink for ease of identification on certain joint exhibits. These will be cited as "Jt. # __ at Red __."

11. The coal for TGS will be Nos. 8 and 9 seam Kentucky coal. It will come from a new underground mine to be located near the facility. Jt. #35. The mine will come into operation before TGS and will have facilities to ship coal to customers other than TGS. The mine will be permitted separately from TGS. *Id*. at 4.

12. TGS will be located on land that is surrounded by reclaimed surface mines and underground mine works. 12/4/04 TE 132-38 (Tickner); Jt.# 7 at 35; P176. TGS will be located in an area that is classified as in "attainment" or "unclassified" under National Ambient Air Quality Standards (NAAQS).

13. Some of the companies which were involved in the project are the following. Black and Veatch was the design engineer for TGS. Burns & McDonnell was also TGS's engineer. ALSTOM is TGS's pollution control contractor. (Babcock & Wilcox is a competitor of ALSTOM.) KEC was TGC's consulting firm for the permitting process.

The Pollution Control Equipment

14. TGC is burning bituminous coal with a sulfur content of roughly 4.4 percent. High sulfur coal is coal with a sulfur content of over 2 percent.

15. The combustion of coal produces emissions including nitrogen oxide, sulfur dioxide, carbon monoxide, volatile organic compounds, acid gases and metals. Jt. #7 at 4; Jt. #57 at Red 16. The final permit emissions based on maximum rated capacity of the plant, worst-case operating conditions, 8,760 hours per year of operation and 100% load are:

Pollutant	Emission Rate TPY
CO	6,599
NO_x	6,029
Particulate Matter (PM)	1,328
SO_2	10,954

VOC	509
Mercury	0.21
Beryllium	0.0615
Fluorides	10.34
H_2SO_4	326

Jt. # 7 at 9, Table 3.1.

16. Each boiler will be tangentially fired and equipped with low-NO_x burners and a selective catalytic reduction (SCR) unit for reduction of nitrogen oxides (NO_x) and for mercury control; a dry electrostatic precipitator (ESP) for control of PM, including mercury; a wet flue gas desulfurizer (FGD)[15] also called a wet scrubber for control of sulfur dioxide (SO_2) and mercury; and a wet electrostatic precipitator (WESP) for control of acid gases and fine particulate, including HAPs. *See* TGC42 for a diagram of the pollution control train.

17. An air preheater (a heat exchanger) is between the SCR and dry ESP, which uses heat in the exhaust stream to preheat combustion air going into the boiler. The terminology used for control equipment upstream of the heat exchanger is "hot side," and downstream controls are called "cold side." Thus, TGS will have a hot side SCR and cold side dry ESP, WFGD and WESP.

18. The SCR is basically a big metal frame in a duct which carries the exhaust gas from the boiler. The frame has window panes and there are blocks of catalyst that are set in each of the window panes. The SCR injects ammonia into the exhaust stream as it is passing over the catalysts and the ammonia combines with the NO_x in the presence of the catalyst to form nitrogen gas and water. 11-6-03 TE 102:25.

Permit Development – Overview

[15] The FGD also provides some control for acid gases such as hydrogen fluoride (HF).

19. The Permit developed over more than a two-year period from the date of the original contact between TGC's consultants in developing the permit application in September 2000 to the date of issuance of the final permit on October 11, 2002. This resulted from two factors. First, there were numerous comments from agencies and the public, and second, the TGC permit addresses a multitude of requirements under a wide range of regulatory programs. *See* Jt. #7 at 9-12. For example, the PSD permit program requires Best Available Control Technology (BACT), a demonstration of compliance with Class I and Class II increment and NAAQS, and an additional impact analysis; the New Source Performance Standards (NSPS) impose technology and monitoring requirements; the case-by-case Maximum Achievable Control Technology (MACT) provision imposes still additional technology requirements. The Compliance Assurance Monitoring (CAM) program of Title V and the acid rain provisions under Title IV impose still more monitoring requirements. Finally, Kentucky law imposes additional requirements.

20. The permitting history is largely found in the Joint Exhibits. First, there was an application, agency requests for more information, investigation and submittal of that information, a revised application, development of a draft permit, publication of a public notice, comments on the draft permit, and responses to those comments. Then, another draft permit was issued, starting the process over again. There were two full cycles of this process in the evolution of the Permit. In addition, NPS and EPA communicated numerous comments on an informal basis.

The Original Permit Application

21. Technical discussions preceded the filing of the permit application. In September 2000, TGC requested and was granted permission to use monitoring information from the nearby

TVA Paradise plant. P102-11. In late 2000, protocols were submitted for air quality modeling. 3/3/04 TE 132-33 (Markin).

22. On February 28, 2001, TGC submitted to DAQ a PSD/TitleV/Acid Rain permit application. Jt. #61. For air permitting purposes, this proposed construction is classified as a new major stationary source. As such, it is subject to PSD, Title V Operating Permit, and Phase II Acid Rain program federal and state requirements. The application addresses PSD annual emissions for carbon monoxide (CO); nitrogen oxides (NO_x); particulate matter (PM/PM_{10}[16]); sulfur dioxide (SO_2); volatile organic compounds (VOCs); mercury (Hg); beryllium (Be); fluorides (as HF); and sulfuric acid mist (H_2SO_4).

23. The initial application provided that the BACT limit for the pollutants which are most at issue in this case to be as follows:

PM/PM_{10}	0.018 lb/MMbtu
SO_2	0.294 lb/MMbtu on a rolling 30 day average
NO_x	0.10 lb/MMbtu based on a 30 day average

Additional information was received on October 28, 2001.

24. A 30-day rolling average was explained as taking the first 30 days and calculating an average, then progressing forward in time and repeating the process through the year. Thus, for each day, there is an average of the preceding 30 days. Dr. Fox explained that the significance of the 30-day average as opposed to a 24-hour average is that a 30-day average tends to smooth out peaks and high values in the record. With a shorter averaging time, i.e. three-hour or 24-hour, there is not as long a record to average out the peaks. So, generally, the shorter the averaging time, the higher the emission rate.

25. Pursuant to 401 KAR 51:017, upon the filing of the permit application, DAQ notified the US Department of Interior (DOI) Federal Land Manager (FLM) for the affected Class I area and also notified U.S. EPA Region 4. Both the NPS (within the Department of

[16] PM_{10} means particulate matter with an aerodynamic diameter less than or equal to a nominal ten (10) micrometers as measured by a reference method based on 40 CFR 50, Appendix J and designated in accordance with 40 CFR 53, or by an equivalent method designated in accordance with 40 CFR 53.

the Interior (DOI) and EPA were extensively involved in the TGC permit. A time line of significant permitting events is contained in the Updated SOB. Jt. #7 at 6-8.

26. On April 23, 2001, the application was logged administratively complete. Jt. #7 at 5; Cab16. At this time the application did not contain a CAM plan or a complete MACT case-by-case determination application.

Comments on the Original Permit Application

27. On April 27, 2001, NPS commented on the permit application. It suggested that the proposed BACT limits for SO_2 and NO_x were acceptable, but questioned the limit for PM. NPS also questioned the accuracy of calculations of sulfuric acid mist and stated that the air quality modeling impacts on Class I areas of the Park were unacceptable. NPS also indicated that it would be reviewing impacts on threatened and endangered species. TGC22.

28. On May 11, 2001, the USFWS determined that the requirements of Section 7 of the Endangered Species Act had been fulfilled. Jt. #17 at Red 166.

29. On May 24, 2001, EPA made initial comments on the air quality modeling. P137-59. Also on this date, DAQ advised TGC that it would not proceed with review of the application until TGC addressed NPS's comments regarding visibility impacts. TGC215.

TGC Re-evaluates Its Proposed Technology

30. On September 6, 2001, TGC sent a letter to DAQ responding to its request to reply to NPS's comments concerning the modeling of visibility impacts and H_2SO_4 (sulfuric acid mist) emissions from TGS. TGC also advised DAQ of the progress made in reducing impacts from TGS. Jt. #60.

31. On September 7, 2001, TGC met with representatives of NPS, USFWS and DOI to discuss the permit application.

The Revised Permit Application

32. On October 1, 2001, TGC submitted revised Class I modeling using the lower projected emissions. Jt. #59.

33. On October 26, 2001, a revised PSD/Title V/Acid Rain permit application was submitted. Jt. #57. The revised permit application contained an updated BACT analysis supporting reduced emissions from the facility for SO_2, NO_x and sulfuric acid mist. Id. at Red 55, Table 4.9.1. It also contained new Class I and Class II modeling analyses and a new Additional Impact Analysis. Id. at Red 92-128. In addition, it contained information for a case-by-case MACT analysis consistent with EPA guidance at the time. Id. at Red 19-21.

34. The revised application provided that the BACT limit for the pollutants which are most at issue in this case to be as follows:

PM/PM_{10}	0.018 lb/MMbtu
SO_2	0.167 lb/MMbtu
NO_x	0.09 lb/MMbtu based on a 30 day average

Comments on the Revised Permit Application

35. On December 3, 2001, EPA's Region 4, Air Planning Branch, submitted initial comments on the revised permit application. Jt. #56 at Red 12. On December 5, 2001, John Bunyak, chief of the Policy, Planning and Permit Review Branch of the Air Resources Division of NPS, sent a letter to John Hornback, director, DAQ. He stated that after TGC satisfactorily addresses NPS's BACT analysis and the air quality analysis and provides requested additional information, he would be in a better position to make an informed decision whether or not the TGS facility would adversely impact visibility or other air quality related values at the Park. Jt. #56 at Red 7. He asked that TGS consider stricter controls on its emissions so as to lessen the

impacts at the Park and that TGS provide an analysis of the feasibility of applying coal cleaning technology and provide an ultimate coal analysis.

36. On December 12, 2001, TGC submitted responses and supporting documentation to comments on the revised permit application by DAQ, EPA, and NPS. This submittal by TGC included information on the control equipment, flow diagrams, Class I and Class II modeling, a coal washing analysis and response from Earth Tech (Joe Scire) to the NPS comments. Jt. #56.

37. In December 2001, NRDC (Natural Resources Defense Council) submitted comments regarding EPA's and DAQ's failure to require consideration of integrated gasification combined cycle (IGCC) or circulating fluidized bed (CFB) technology. TGC responded to these comments in a letter dated January 25, 2002. TGC185 at Att. 10.

38. On December 21, 2001, KEC submitted a Case-by-Case MACT determination. Jt. #55. In conclusion, the determination stated that TGS's combination of Low NO_x burners; SCR; particulate control; wet FGD; and WESP should be accepted as the best available means of controlling hazardous air pollutant emissions including mercury.

The First Draft Permit

39. On January 2, 2002, KEC submitted another version of the case-by-case MACT Supporting Information for TGS. Jt. #54.

40. On January 2, 2002, the first draft permit and Preliminary Determination and SOB were issued for public comment. Jt. #2 and #3. The draft permit contained the following emission limits:

SO_2	0.167 lbs/MMbtu on a 30 day rolling average
PM/PM_{10}	0.018 lbs/MMbtu
NO_x	0.09 lbs/MMbtu based on a 30 day average

41. During the initial public comment period, TGC submitted additional modeling information in response to questions from NPS and EPA. On February 5, 2002, Earth Tech submitted a report indicating that an error in meteorological data used for the Class I modeling overstated the predicted impacts from TGS. Jt. #51 at 2. The report concluded that modeling based on accurate weather data showed TGS would not cause adverse impacts. Id.

42. The public comment period began January 9, 2002. Jt. #17 at Red 93. The public hearing was held on February 12. DAQ announced an extension of the comment period for an additional 20 days (until February 28, 2002) to allow the public additional time to review the modeling. Id.

43. On January 11, 2002, by Executive Order No. 2002-50, Governor Patton lifted the suspension to allow acceptance of new applications, but to prohibit the issuance of permits for said facilities. Jt. #10.

Agency Reaction to the First Draft Permit

44. On February 14, 2002, the Assistant Secretary for USFWS sent DAQ a letter which stated that based on DAQ's preliminary determination which was received on January 2, 2002, it believed that the proposed emissions would have an adverse impact on visibility and could potentially affect federally listed threatened and endangered species at the Park. Shaver Ex. 28 at 2 (attached to P167). NPS stated that it would review the new modeling, received on February 6, 2002, which it said appeared to show significantly less impact. Id. at 1.

45. On February 26, 2002, EPA forwarded to DAQ detailed comments on the initial draft permit. P23.

46. TGC filed responses to public and agency comments on February 28, 2002 (TGC185), March 10, 2002, Jt. #44; TGC39, and May 10, 2002, Jt. #41. On April 17, 2002, DAQ responded to comments. Jt. #43.

The May 29, 2002 Permit Addendum

47. On May 14, 2002, representatives of EPA, DAQ, and TGC met to discuss outstanding issues on the permit in order to develop a plan for reaching closure on them. 12/4/03 TE 144 (Tickner). In response to inquiries from DAQ, EPA, and NPS, on May 29, 2002, TGC filed an addendum to its permit application which contained a refined BACT, CAM and MACT analysis along with additional information on modeling. Jt. #33.

48. On May 24, 2002, KEC sent DAQ a letter in justification of its position that the mine and TGS are two distinct facilities and should not be considered a single source. Jt. #35 and 36A.

49. Also, on May 24, 2002, TGC sent DAQ a letter in response to NPS letters of February 14 and April 15, 2002, and attached a report on coal washing entitled Analysis on Issues Related to Pre-Combustion Coal Cleaning for Sulfur Reduction: Thoroughbred Generation Station by Rick Honaker, Associate Professor, Department of Mining Engineering, University of Kentucky. The report concluded that coal washing to reduce sulfur content by 40% or more is not technically or economically feasible. Jt. #36.

50. On May 29, 2002, TGC submitted an Addendum to its October 2001 application. The Addendum included Table 4.2-1 entitled BACT Comparison of New, Proposed, and Permitted Coal Fired Power Plant Emission Limits. Jt. #33.

The Second Draft Permit

51. On June 19, 2002, the second draft permit and Revised Preliminary Determination and SOB were issued. Jt. #4 and 5.

PM/PM_{10}	0.018 lb/MMbtu	
SO_2	0.167 lb/MMbtu	based on a 30 day rolling average
SO_2	0.45 lbs/MMbtu	based on 24 hour block average
NO_x	0.08 lb/MMbtu	based on a 30 day average

Notice of the public hearing and availability of draft permit appeared in the Greenville Leader-News on June 19, 2002, giving notice that a second public hearing would be held on July 25, 2002. Jt. #24. In response to public and agency comments, TGC submitted additional modeling in support of a short-term SO_2 limit of 0.41 lbs/MMbtu. Jt. #22, 23. At the second public hearing, DAQ announced an extension of the public comment period until August 24, 2002. Cab18 at 2.

Addressing Concerns of the NPS

52. On August 8, 2002, TGC representatives met with Fran Mainella of the NPS and members of her staff to work out technical issues related to the short-term SO_2 limit.

53. On August 9, 2002, TGC responded to DAQ on issues raised by NPS regarding BACT and acid deposition issues at the Park and concluded that the 0.41 lb-SO_2/MMbtu 24-hr average, in conjunction with the 0.167 lb-SO_2/MMbtu 30-day rolling average, is protective of NAAQS, PSD increment and visibility and should be approved. Jt. #20.

54. On August 21, 2002, Peabody Holding Company, Inc., made a donation of $50,000 to the Republican National Committee. Stipulation by TGC; Docket #140.[17] The parties

[17] Petitioners allege that as a result of campaign contributions by Peabody to the Republican party, Peabody gained access with the NPS, i.e. meeting with NPS Deputy Secretary Griles. PD153-29 is a demonstrative exhibit showing the correlation between the dates when campaign contributions were made and the dates of decisions affecting TGC's permit.

Other evidence adduced during the formal hearing regarding the NPS's involvement with the permit is as follows:

stipulated to the authenticity of Exhibit #36 to Petitioners' Response to the Cabinet's Motion for Summary Disposition, which is a printout from the Common Cause website showing soft money donations for 1/01/2001 through 12/31/2002 from both Peabody Holding Co, Inc. and from Black Beauty Coal (a Peabody subsidiary) to the Republican party. Docket #140.

55. After several discussions on issues related to the short term SO_2 limit, on August 22-23, 2002, TGC and NPS exchanged letters in which TGC committed to reduce the 0.41 lbs SO_2/MMbtu short-term limit based on two years of operating data with a target of 0.23 lbs/MMbtu. Jt. #18, 19.

56. On August 22, 2002, the Assistant Secretary for USFWS issued a letter to DAQ withdrawing its previous determination (issued on February 14, 2002) that emissions from TGS would adversely impact visibility and potentially affect federally-listed threatened and endangered species at the Park. Jt. #19. The withdrawal of the adverse impact finding was based on a new modeling analysis from TGC identifying errors in the meteorological data used in TGC's prior analysis. The revised analysis was reviewed and verified by NPS staff experts.

57. In addition, the Assistant Secretary stated that based on an air quality modeling analysis conducted by the NPS of the 24-hour SO_2 limit of 0.41 lbs/MMbtu limit, NPS found potential adverse impacts on visibility at the Park at that level. NPS assessed alternative limits and found that at the 0.23 lbs/MMbtu level there would be no adverse impacts on visibility at the Park.

Mark DePoy's office, the Division of Science and Resources Management for the Park, got a call from the Director of the NPS asking that his office cooperate to the greatest extent possible with all entities involved in the permit.

Don Shepherd, of the Air Resources Division for NPS, testified that no one at NPS ever asked him to give special favors to TGC as a result of political contributions. He also said he never felt that his job was in jeopardy as a result of his views about the TGC permit.

58. He further stated NPS understands that TGS is willing to accept permit language that would lower the 24-hour limit based on actual operating data for the facility. Based on two years of operating data, DAQ would revise the 0.41 lbs/MMbtu permitted limit downward, with a target emission limit of 0.23 lbs/MMbtu or lower, consistent with plant operating experience and a reasonable margin to assure compliance. This good faith commitment by TGC to lower the 24-hour limit confirmed NPS' comfort level with the issuance of the permit. Jt. #19.

59. On August 23, 2002, TGC sent a letter to DAQ summarizing the resolution of issues with the NPS and indicating that NPS would be sending a letter to DAQ withdrawing its previous adverse impact finding. The letter from TGC is Jt. #18; as mentioned in the above paragraph, the letter of withdrawal is Jt. #19. Specifically, TGC stated that the resolution with NPS would be based on the following:

*TGS is expected to routinely operate close to the numerical value of its 30-day emission limitation and well below the highest allowable short-term limit contained in the permit, but cannot get a vendor guarantee for a short-term emission limitation below 0.41 lb/MMbtu.

*NPS can meet its mandate to protect visibility at the Park if Kentucky finalizes the draft permit to reflect the 0.41 lb/MMbtu rate and include a condition indicating that Kentucky will:

*re-examine the 24-hour emission limitation for TGS' Units 1 and 2 after Unit 1 has been in operation for 2 years after its initial compliance demonstration (by then, Unit 2 would have been in operation a somewhat lesser period, about 6 months less), and

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In addition, the White House Energy Task Force telephoned the Park to determine where the permit was in the process.

*revise that emission limitation downward (a) consistent with plant operating experience and a reasonable margin to assure compliance and (b) with a target emission limit of 0.23 lb/MMbtu or lower. Jt. #18.

60. On August 28, 2002, Peabody Holding Company made a donation of $100,000 to the National Republican Senatorial Committee. Stipulated; Docket #140.

61. On September 16, 2002, TGC submitted to DAQ its responses to comments submitted by EPA Region 4 on July 18, 2002; response to other comments submitted during the public comment period; suggested revisions to the draft permit published on June 19, 2002; and suggested revisions to the preliminary determination SOB published on June 19, 2002. Jt. #17.

The Final Permit

62. On October 11, 2002, the Cabinet issued the final Title V/PSD Air Quality Permit V-02-001 to TGC, and Updated SOB. Jt. #6 and 7. It incorporated the short-term SO_2 limit and commitment for re-evaluation. Jt. #6.

63. Emission limitations of the final permit include the following:

• Nitrogen oxides:	.08 lbs/MMBTU, 30-day rolling average
• Sulfur dioxide:	.167 lbs/MMBTU, 30-day rolling average; .41 lbs/MMBTU, 24-hour block average (subject to optimization study targeting a revision to .23 lbs/MMBTU, 24-hour)
• Particulate emissions:	.018 lb/MMBTU heat input, 3-hour average
• Opacity:	20%, 6-minute average
• Carbon monoxide:	.10 lbs/MMBTU, 30-day rolling average
• Volatile organic compounds:	.0072 lbs/MMBTU, 30-day rolling average
• Beryllium:	.000000497 lbs/MMBTU, 30-day rolling average
• Sulfuric acid mist:	.00497 lbs/MMBTU, 30-day rolling average
• Hydrogen fluoride:	.000159 lbs/MMBTU, 30-day rolling average
• Mercury:	.00000321 lbs/MMBTU, quarterly average
• Lead:	.00000386 lbs/MMBTU, quarterly average

Jt. # 8, at 2–3.

As to hazardous air pollutants (HAPs) under case-by-case MACT, they are limited as follows in tons per year:

VOC (HAPs)	5.154;
mercury	.1047;
hydrogen chloride	26.90;
hydrogen fluoride	5.1684;
arsenic	.0288;
beryllium	.0308;
chromium	.3419;
manganese	.6825;
lead	.126;
cadmium	.0238.[18] Id., p. 4.

[18] It appears that this figure for cadmium is a typographical error and should be *.0119 for each unit*, instead of .0238, pursuant to testimony. *See* Adams, 2-5-04, 175:16 – 176:10., and 4-15-04, 72:23-25. *Also see* TGC's 7-1-04

The permit also includes testing, monitoring, record keeping, and reporting requirements.

EPA's Requested Clarification

64. On November 6, 2002, EPA asked for clarification on two minor points to assure that (1) the SO_2 short-term limit could only go down and not up as a result of the re-evaluation and (2) the PSD-required provisions did not expire with the Title V permit in five years. TGC67 and 217 at 1. On December 6, 2002, DAQ administratively revised the permit to address EPA's questions. Jt. # 8 – Revision #1.

65. Petitioners filed a petition for hearing (File No. DAQ-26003) on November 11, 2002, to contest the October 11, 2002 permit. On January 13, 2003, Petitioners filed another petition (File No. DAQ-26048) with identical allegations but added Count 16 to formally include the revised permit, Revision #1 in the litigation. The cases were subsequently consolidated. On April 19, 2005, by Agreed Order, this case will also include Petitioners' challenge to Revision #2.

66. On April 10, 2003, the Army Corps of Engineers issued a permit to TGC to construct water intake and discharge structures, a barge unloading dock, and a barge fleeting area in support of the new electric generating facility. Jt. #62.

VI. FINDINGS RELATING TO MAMMOTH CAVE NATIONAL PARK

67. There are 48 NPS areas which are designated Class I areas. Mammoth Cave National Park is the only Class I area in Kentucky. TGS will be some 46 miles in a west-

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letter, Docket# 299, p. 2 – 3, and the Petitioners' July 30, 2004 response letter expressing agreement. Docket# 300, p. 2.

northwest direction from the Park. P193.

68. Mammoth Cave is a Biosphere Reserve and a World Heritage Site and is considered a highly significant cave and karst area. There are 2,000 acres on the surface that support the cave system. The Park has 1.8 million visitors a year; 25 percent go in the cave.

69. Mammoth Cave is the longest known cave system in the world, and the south central Kentucky karst region is as well developed as any karst region in the world. Ten or 12 miles of the cave were explored by the native Americans and because of the very stable conditions in the Park, there are artifacts that are remarkably preserved. Karst areas are very vulnerable to contamination through pollution. The karst system in the Park is extremely sensitive because of the global significance of the features that it contains. The Park contains a portion of the Green River which is classified as a wild river and is also designated as a National Scenic River.

70. The NPS has a responsibility under the CAA to review permits for new sources that wish to locate near national parks. Permit applications are sent to the Air Resources Division of the NPS in Denver. The Air Resources Division is a resource to the superintendents and to the director of the NPS and to the DOI Assistant Secretary for USFWS, who is the Federal Land Manager (FLM) for the Park. The initial notification from DAQ to the NPS came in December, 2000.

71. With regard to who has the burden of proof for Class I air protection, if there is no exceedence of Class I increment, the FLM must demonstrate to the state's satisfaction that there

will be an adverse impact on air quality related values. If the increment is exceeded, no permit can be issued unless the NPS certifies that there will not be an adverse impact.[19]

72. The purpose of FLAG, a guidance document for the FLM, is to provide both permit applicants and state permitting authorities a heads-up as to what the needs are of the Air Resources Division with regard to permits which are submitted for NPS review. Donald Shepherd says that the FLAG procedure is an effort by the federal land managers to bring some consistency to the way NPS looks at PSD permit applications. Christine Shaver, chief of the Air Resources Division of the NPS, made a decision that FLAG would not apply to TGC because TGC's modeling protocol had been received by a date that had been established for grandfathering from FLAG (March 1, 2001). In addition, the permit application was received by the date which had been determined in order to be grandfathered (prior to April 1, 2001). Nevertheless, Shaver said that some of the criteria and information in FLAG was taken into account where it helped streamline and inform NPS's review. However, NPS did not hold TGC accountable for providing the information that FLAG would have required.

73. According to Shaver, the Park has severely impaired visibility. It is the worst visibility measured, in some ways, of any of the national parks. She explained that an adverse impact call is quasi-technically based, but is a policy type decision. The policy decision is

[19] Increments are a bookkeeping exercise to keep track of changes in air quality. An increment is a measurement of a concentration difference under the PSD program. The goal of the increment program is not to allow new sources, in cleaned areas, to pollute up to the NAAQS. The PSD program is designed to only allow an increment amount of pollution above a baseline value that is much less than the available concentration space between the current baseline and the NAAQS. Only sources with changes in emissions after the baseline date are increment sources. There are different increments for different criteria pollutants. The increments are expressed in a concentration of air pollution, and the unit is micrograms per cubic meter. For example, for SO_2, the increment for a Class I area for 24 hours is five micrograms per cubic meter. 11-21-03 TE at 16-20 (Scire).

made by the assistant secretary for USFWS and the NPS, for which Shaver's office provides technical information. In the August 22, 2002 letter from USFWS withdrawing the adverse impact, she said her office accepted as a compromise allowing TGC to operate for two years at emission levels that NPS believed would hurt visibility. Shaver said that NPS never accepted DAQ's finding on coal washing. P167 at 58.

74. Shaver said that at the 0.41MMbtu 24 hour SO_2 emission limitation, there were only two days out of a three-year period where the NPS's threshold for concern was exceeded. NPS did model the impacts of the plant against natural conditions and it was well above the thresholds of concern. The endangered species concerns were raised on an independent, parallel track with the USFWS. She said that "certainly Mammoth Cave has severely impaired visibility. It is the worst visibility measured, in some ways, of any of our parks, and much more impaired than the natural condition would be." P167 at 112. "(T)he whole issue of the 24 hour limit and how that affected the visibility analysis and the visibility impacts arose after that notice was published and we continued to have concerns that the public really was not aware of a lot of the debate going on". Id. at 116.

75. Mark DePoy, chief of the Division of Science and Resources Management for the Park, directed three scientists in his division, Bob Carson, Rick Olson and Kurt Helf, to conduct literature searches and prepare briefing papers on how the permit would affect threatened and endangered species. P195, Carson 1, 2 and 3. The papers were given to the superintendent's office and sent to the FWS, to Dianna Tickner, and to DAQ. While these papers were not considered by DAQ in making permit decisions, there were two meetings involving Mammoth Cave scientists, DAQ, and EPA.

76. There are 12 threatened and endangered species that occur in the Park, including the Kentucky cave shrimp, the Indiana bat and the gray bat, and in the Green River there are seven endangered mussel species. Based on the initial modeling data, which showed a potential impact to threatened and endangered species, the Division of Science and Resource Management recommended to the superintendent of the Park, who is the FLM, and to the director of NPS that there was a strong likelihood for adverse impact to both federally listed threatened and endangered species and visibility. Dr. Poulson testified that there are a number of special status species in the Park: Green River has one of the highest diversities of species of freshwater mussels in the world; two species of insect-eating bats; the gray bat and the Indiana bat, both federally listed as endangered; Mammoth Cave shrimp; and two species of cave fish. Dr. Poulson was not involved in public commenting about the permit.

VII. FINDINGS RELATING TO IDEM

77. The TGC facility is approximately 37 miles from the Indiana border. Indiana is in EPA's Region 5. IDEM's motivation for its involvement with the TGC permit was two-fold: the potential impact on air quality in Indiana and the concern for consistency across the country in the issuance of PSD permits. Indiana has not issued any new permits for coal-fired units in the last five years. IDEM's comments on the TGC permit were based on what the federal PSD program requires.

78. On February 7, 2002, Janet McCabe, assistant commissioner of IDEM's Office of Air Quality, sent a letter to John Lyons, DAQ's director, outlining the extensive comments

of Indiana on the TGC draft permit in two attachments to the letter. This letter is included in IDEM #5 to P159.

79. On August 23, 2002, McCabe sent another letter to Lyons regarding Indiana's comments on the revised draft permit for the TGC facility. While noting that the revised draft permit, technical support documents and other documentation did address a number of concerns raised by Indiana, the letter notes that a significant number of substantial technical and policy issues remained. IDEM #5 to P159[20]. The IDEM comments which McCabe believed were not responded to by DAQ were as follows:

> TGC should evaluate using lower sulfur coal;
>
> TGC should evaluate all facilities with lower SO_2 and NO_x limits than the BACT limit TGC proposed, i.e. explain its rationale for why a smaller unit could achieve much better efficiency than the proposed TGC units;
>
> DAQ should include minimum control efficiency for SO_2, not just a limit in pounds per MMbtu;
>
> DAQ should have evaluated a baghouse with carbon injection to control mercury emissions;
>
> The permit did not limit condensable particulate emissions;
>
> DAQ did not explain how lead emissions were determined;
>
> DAQ did not evaluate whether using a mercury CEMS (Continuous Emissions Monitoring System) would be feasible;
>
> DAQ did not explain why quarterly fuel sampling and analysis for HAPs was sufficient; and
>
> DAQ did not do a BACT analysis or place BACT limits on the smaller type units such as the coal handling system and the fly ash handling system.

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[20] The exhibits to P159 are labeled IDEM #1-6 (IDEM #3 & 4 admitted by avowel); IDEM #5 contains three letters.

80. At IDEM's request, DAQ personnel met with IDEM personnel to discuss their concerns.

81. Nisha Sizemore is an environmental engineer who is a technical environmental specialist in the Permits Branch of IDEM. She was charged with reviewing the BACT analysis submitted by TGC and was involved in making comments on the TGC permit. Her prior experience includes performing two BACT analyses for coal-fired power plants (which were CFB plants on which the BACT analyses were not completed because the permits were not pursued to completion) and a MACT analysis for a foundry.

82. On November 12, 2002, IDEM Commissioner Lori Kaplan sent a letter to Jeffrey Holmstead, Administrator of the EPA, stating that Indiana did not intend to appeal the final TGC permit because IDEM had determined that an adequate demonstration had been made that air quality standards would not be jeopardized as a result of emissions from the TGC facility. However, she also stated that IDEM remained concerned that the conditions in the final permit were not consistent with conditions that would have been established in a PSD permit reviewed for a comparable source in Indiana or within any Region 5 state. Commissioner Kaplan went on to state that the final permit and response to comments did not address numerous specific issues raised by IDEM, which were included with the letter as Attachment 3. IDEM #5. The response from EPA was that Region 4, an active participant in the permitting process, believed that the permit met the state's rules implementing the approved PSD program in Kentucky. IDEM #6.

VIII. FINDINGS OF FACT[21] RELATED TO EACH COUNT, ARGUMENTS OF THE PARTIES, AND CONCLUSIONS ON COUNTS 1, 2, 8, 9, 10, 11, 14, 17, AND 18

COUNT 1 – Air Toxics, Risk

COUNT 1 - Findings
Overview

83. The issue in this Count is whether 401 KAR 63:020[22], referred to as Kentucky's air toxics regulation, requires the Cabinet to conduct an ecological risk assessment to determine if the potentially hazardous matter or toxic substances to be emitted from TGS will be harmful to animals and plants, or whether the Cabinet's responsibilities under 401 KAR 63:020 are satisfied by the Cumulative Assessment.

84. DAQ acknowledges it did not perform an ecological risk assessment in its evaluation of the TGC permit. However, the Cabinet and TGC maintain that the Cumulative Assessment, Jt. #11, in which the Cabinet studied the cumulative environmental effects of the

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[21] The Findings of Fact are based on the evidence and the record as a whole. The findings include only those facts I deem material to the ultimate outcome, and do not constitute a summary of all testimony given.

[22] Chapter 63 is the DAQ's chapter on General Standards of Performance. Section 1 of 401 KAR 63:020 addresses the applicability of this regulation. Section 1 provides the regulation applies to each affected facility "which emits or may emit potentially hazardous matter or toxic substances .. provided such emissions are not elsewhere subject to the administrative regulations of the Division for Air Quality." Early in this case, TGC filed a motion for dismissal of Count 1 on the basis that the air emissions from the proposed facility are "unquestionably 'elsewhere subject' to substantial DAQ regulation". The Cabinet disagreed with TGC's argument, Docket #21. I denied the motion to dismiss Count 1. Docket #42. Again, in its post hearing brief, the Cabinet reaffirms its position that 63:020, which is part of Kentucky's EPA-approved State Implementation Plan (40 CFR 52:090(c)), does apply to the TGC permit. The Cabinet explains that 63:020 is risk-based as opposed to technology-based. The Cabinet cites Sierra Club v. EPA, 353 F.3d 976 (D.C. Cir. 2004), where the U.S. Court of Appeals for the D.C. Circuit provides background for the restructuring of Section 112 of the CAA in an effort to reduce HAPs with technology-based standards (by requiring EPA to publish a list containing each HAP for which it intends to establish an emission standard and then either promulgating an emission standard or explaining why the particular HAP is in fact not hazardous). The technology-based regime replaced an earlier risk-based regime that required EPA to regulate at a level that provided an ample margin of safety to protect the public. Mossville Environmental Action Now and Sierra Club v EPA, 370 F.3d 1232, 1236 (D.C. Cir. 2004). The earlier risk-based analysis proved to be more difficult than anticipated. The ineffectiveness of the risk-based approach created a consensus that the program to regulate HAPs should be restructured to provide EPA with authority to regulate with technology-based standards. The emission standards are based on the maximum achievable control technology (MACT) for sources in each category, not on an assessment of the risks posed by HAPs, Sierra Club, *supra*, at 979, 980.

development of new electric generating facilities (including TGS), satisfies its responsibility under 401 KAR 63:020 Section 3. Specifically, they urge that the human risk assessment conducted in the Cumulative Assessment, with safety factors added, was sufficient to determine that there would be no risk to animals and plants.

85. Petitioners urge that DAQ's reliance on the human health assessment in the Cumulative Assessment, in which only the inhalation pathway was studied, runs counter to the well established fact that wildlife are exposed to the toxic and hazardous substances emitted by TGS in a variety of different ways, such as through eating contaminated food and drinking contaminated water, pathways which the Cumulative Assessment ignored.

General Findings

86. 401 KAR 63:020 provides in Section 3 as follows:

> Persons responsible for a source from which hazardous matter or toxic substances may be emitted shall provide the utmost care and consideration, in the handling of these materials, to the potentially harmful effects of the emissions resulting from such activities. **No owner or operator shall allow any affected facility to emit potentially hazardous matter or toxic substances in such quantities or duration as to be harmful to the <u>health and welfare of humans, animals and plants</u>. Evaluation of such facilities as to adequacy of controls and/or procedures and emission potential will be made on an individual basis by the cabinet.** (Emphasis added.)

87. Section 1 provides that 401 KAR 63:020 applies to "<u>each affected facility</u> which emits or may emit potentially hazardous matter or toxic substances…". "Affected facility" includes "an apparatus, building, operation, road, or other entity or series of entities which emits or may emit an air contaminant into the outdoor atmosphere." 401 KAR 63:001, Section 1(1).

88. TGC's permit states that 401 KAR 63:020 applies to Emissions Units 1 and 2 (the PC boilers), and Emission Unit 3 (the Auxiliary Boiler). Jt. #6 at 2 and 15. The applicability of

63:020 is not addressed in the SOB, Jt. #5, which was issued with the draft permit, Jt. #4, or in the later SOB, Jt. #7, which was issued with the final permit, Jt. #6. Neither the permit, SOB, nor the Cumulative Assessment, Jt. #11, states that the Cabinet's obligations under 63:020 were satisfied by the Cumulative Assessment.

89. Petitioners presented the testimony of Dr. Christopher Groves, an expert in hydrogeology and karst systems and the Park, as well as the testimony of Dr. Thomas Poulson, an expert in cave biology, on Count 1. In addition, Dr. Phyllis Fox, a registered environmental assessor, testified on this Count. The Cabinet presented the testimony of Dr. Westerman, branch manager of the Risk Assessment Branch of the Cabinet's Division of Environmental Services, who has 33 years of experience in environmental evaluation, environmental toxicology and risk assessment. In addition, Larry Taylor, an environmental scientist IV with the Cabinet's Department for Environmental Protection, and who was extensively involved with the Cumulative Assessment, testified on this Count.

90. As stated, the Cabinet did not perform an ecological risk assessment in its evaluation of the TGC permit. Dr. Westerman testified that the Risk Assessment Branch, of which he is branch manager, has never been asked to do a "full blown human health risk assessment" or "a full blown ecological risk assessment" for purposes of satisfying 401 KAR 63:020 or for a PSD application. 2-6-04 TE at 51-52. The reason effects on ecological receptors were not evaluated in the Cumulative Assessment, as explained by Dr. Westerman, was that there was not sufficient time because the Governor had given the Cabinet only six months to complete its study. 2-20-04 TE at 91:9-15. The Cabinet urges, however, that as a result of its quantitative evaluation of human health risks which it performed for the Cumulative Assessment that it performed a *qualitative* evaluation of ecological risks.

Facts relating to biomagnification and bioconcentration; and the sensitivity of species at the Park

91. The testimony of Petitioners' experts, which follows, as to the dangers of biomagnification and bioconcentration and as to the sensitivity of certain species at the Park, was not disputed. Moreover, it was not disputed that the karst areas in Mammoth Cave are particularly susceptible to groundwater contamination because water on the surface directly enters the groundwater through sinkholes and other features without the filtering that occurs in non-karst areas. The testimony of Dr. Poulson and Dr. Groves is found at 11-5-04 TE.

92. There are four exposure pathways through which animals can be exposed to toxic substances: 1) breathing air or water, 2) contact with skin, 3) consuming food, and 4) drinking water. Certain toxic substances like mercury bioconcentrate in animals, which means that contaminants are taken up by various exposure pathways faster than they can be excreted or detoxified so that the toxic substance builds up in the animal. Substances can also biomagnify, which means the further up the food chain, the greater the concentration of the toxic substance will be found. Biomagnification can result in a million fold increase in a toxic substance from the bottom of the food chain to the top of the food chain. The dangers of biomagnification and bioconcentration of toxic substances is especially real for species of animals that live a long time.

93. Many of the toxic substances emitted from coal fired power plants such as arsenic, beryllium, cadmium, chromium, lead, manganese, nickel, dioxins and mercury biomagnify and bioconcentrate. These substances are persistent, meaning they will exist in the ambient environment for an extended period of time, thus increasing the chances of animals being exposed to them. Some of the substances, like dioxin, are endocrine disruptors.

Disruption of the endocrine system can have a variety of adverse sublethal effects such as making animals incapable of reproducing or changing the sex of offspring.

94. Dr. Poulson explained the concept of bioconcentration through the food exposure pathway. For things that are rare in the environment, like heavy metals, like lead and mercury and cadmium, organisms do not have mechanisms for dealing with these. Thus, if these substances get into the organism, not much of it gets out. When it accumulates in the body, the longer an organism lives, the higher the concentration would be. The more difficult concept to understand is called bio-magnification where the amounts of toxin concentration get magnified with each step of the food chain. There are two methods, bio-accumulation and bio-magnification, which work together so that the results in terms of concentrating toxins are even greater. Organisms at the top of the food chain and which live a long time are doubly at risk and may overall have concentrations that go up millions, if not billions-fold from the ambient concentration in the environment. With regard to HAPs (arsenic, beryllium, cadmium, chromium, lead, manganese, mercury, nickel and dioxins), they bio-accumulate and bio-magnify.

95. The Park and surrounding area contain numerous mussels, two species of bats, two species of cave fish and a cave shrimp that are all on the Endangered Species Act list. The cave shrimp and cave fish are particularly threatened by pollution because they are long lived and because the geography and geology of the Park and surrounding area results in concentrations of pollutants. Heavy metals adversely affect the ability of cave shrimp to reproduce. The endangered Gray and Indiana Bats are also susceptible to bioaccumulation and biomagnification of toxic substances emitted from TGS. The bats face an added danger because they can forage for distances of up to 100 miles, so they may be exposed to TGS pollution over a broader range. The federally listed mussels are also subject to bioaccumulation because they can

live up to 50 years. In comparison, most humans' risk of exposure is relatively minor because the humans are only in the Park for a short time. More importantly, most humans are not exposed through the food chain, with the exception of people who consume fish from the Green River.

96. Several scientists employed at the Park prepared briefing papers, or literature searches, on the potential impacts of the TGC permit on threatened and endangered species. These papers were developed for the FWS and were also sent to DAQ, and to TGC. (The papers were prepared by Rick Olson – on the ramifications of increased acid deposition; Bobby Carson – on additional ozone levels; and Kurt Helf - on mercury toxicity and contamination. All are found as exhibits to P195.) The papers were not based on actual studies showing that the plants and animals at the Park will be harmed by TGS's emissions.

97. The USFWS, in a letter to the U.S. Army Corps of Engineers recommending denial of a permit for outfall structures on the Green River in support of the power plant, urges that "(b)ased on existing data, the potential for primary and secondary direct, indirect, and cumulative impacts to endangered and threatened species resulting from construction and normal operations of the proposed facility exists and must be evaluated further". P93 at 7. The letter took notice of the Cabinet's Cumulative Assessment and noted that air quality issues at the Park are a significant concern based on the 12 federally listed threatened and endangered species within the Park. Id. at 6. The Corps issued the permit for the outfall structures on April 10, 2003. The permit issued by the Corps is not at issue in this case. Jt. #62.[23]

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[23] See also Interim Report, Appendix 3**,** granting TGC's motion for directed recommendation on Count 7 on the issue of whether DAQ was required by 401 KAR 51:017, Section 18, to coordinate its review with the review of the Corps. I concluded that DAQ was not required to coordinate its review of the TGC air quality permit with the Corps' consideration of a permit for the outfall structures.

The Cumulative Assessment

98. By Executive Order 2001-771 issued June 19, 2001, Governor Patton issued a six-month moratorium on permits for new power plants in order to evaluate the impact of an increase in Kentucky's electric generating capacity. He directed the Cabinet to study the cumulative environmental effects of the development of new electric generating capacity, as well as the resulting impact on existing environmental programs administered by the Cabinet, including compliance with the CAA, the Resource Conservation and Recovery Act, and their state equivalents. Jt. #10.

99. The Cumulative Assessment was issued on December 17, 2001, in response to the Governor's Executive Order. Jt. #11.

100. TGS was one of the proposed power plants selected for evaluation as part of the Cumulative Assessment. 3-3-04 TE at 52 (Taylor); 2-4-04 TE at 52 (Ecton).

101. The Cumulative Assessment concluded that the "proposed plants will not create new environmental problems and will not extensively exacerbate existing conditions." Jt.#11 at 11. The Cumulative Assessment was the most comprehensive evaluation of the health impacts of emissions from power plants in the Commonwealth. 3-3-04 TE at 52 (Taylor); 2-4-04 TE at 52 (Ecton); 4-14-04 TE at 91 (Adams).

102. The Cumulative Assessment is organized as follows: The executive summary gives a general overview of all of the issues associated with power plants. This is followed by conclusions and then recommendations as a result of the study. Next, there is a general overview of the following: a power plant summary (including the 34 existing power plants and 22 proposed constructions or expansions since October 1999), the methodology, types of waste generated and disposal, then the four categories of impacts: air quality impacts, water quality

impacts, land quality impacts, and secondary impacts. There are numerous appendices, labeled A – I: A – U.S. EPA CMAQ (Community Multiscale Air Quality) Modeling Results Power Generating Units in Kentucky; B – Air Toxics Analysis for Proposed and Existing Electricity Generating Units in Kentucky; C – Surface Water Outfall Risk Evaluation; D – Ash Landfill Risk Evaluation; E –Kentucky Power Plants: Ecological Impacts Evaluation; F – Power Plants Impact Study Water Supply Issues; G – Derivation of Human Health Screening Values; H – Summary of the Toxicity of Chemicals Related to Power Plants; and I – Kentucky Fish Advisories.

103. The first step in the air toxics analysis for the Cumulative Assessment was the selection of HAPs to be evaluated. The Cabinet started with a list of 188 pollutants identified in the CAA as the full universe of HAPs.[24] Based on the various forms of fuel being utilized, the Cabinet determined that the existing and proposed power plants in Kentucky, including TGS, have the potential to emit approximately 59 HAPs. From the list of 59 HAPs, the Cabinet used a "concentration toxicity screen" to focus its evaluation on 13 HAPs, which were identified as the contaminants of concern most likely to contribute significantly to human health risks due to high emissions and/or high toxicity. 3/3/04 TE 85 (Taylor).

104. This toxicity screening mechanism is consistent with EPA guidance on how to perform a risk assessment and was used by the EPA in its 1998 study of HAPs, U.S. EPA's Study of Hazardous Air Pollutants from Electric Utility Steam Generating Units – Final Report to Congress, dated February 1998. P107-5. Staff from both DAQ and the Risk Assessment Branch developed Risk Based Screening Values (RBSVs) for the 59 identified HAPs to satisfy the

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[24] Congress listed these HAPs in Section 112 of the CAA as the basis for regulating emissions of these pollutants from all types of industrial sources, not just power plant emissions. 42 U.S.C.A. Section 7412(a)(1), (d).

toxicity prong. They eliminated pollutants that had relatively low emissions and high RBSVs. The process used to develop the RBSVs, is similar to the one EPA Region 9 used to establish its Preliminary Remediation Goals (PRGs). The Cabinet, however, used more conservative exposure factors than Region 9 in developing the RBSVs. This procedure produced the final list of 13 HAPs, which were chosen on the basis of which contaminants are likely to contribute to human health risk.

105. After the concentration toxicity screen identified 13 HAPs for further evaluation, DAQ performed detailed modeling to determine the impact of TGS's emissions for those 13 HAPs. The Cabinet's evaluation was conservative based on the following: 1) the modeling was performed using maximum emission rates from TGC's application or EPA's AP 42 database[25], whichever rate was higher; 2) the maximum emission rates from TGC's February 2001 application were used, whereas emissions dropped from the initial application and the final permit for mercury, H_2SO_4 and NO_x; and 3) the Cabinet assumed that all the proposed power plants would be constructed and operated and all existing power plants would continue to operate.

106. Modeling for the Cumulative Assessment demonstrated that TGS's air quality impacts are less than 1/10 of the conservative screening values in all cases, and less than 1/100 of the screening values for most pollutants, including mercury.

107. In its Study of Hazardous Air Pollutants, P 107.5, EPA stated that for many HAPs, it is believed that inhalation was the dominant exposure pathway but for HAPs that are persistent and/or bioaccumulate, and are toxic by ingestion, the non-inhalation exposure

[25] The AP 42 database is deferred to when an applicant does not have emission factors that are specific to a source. TGC 119. AP 42 was referred to by Dr. Fox as the emission estimating bible.

pathways could be more important. Based on a screening and priorization assessment, the EPA identified four high priority HAPs (radionuclides, mercury, arsenic, dioxins) to assess for non-inhalation exposures. Id. at Pg. ES-4. Multipathway assessments were presented for these four high priority HAPs, with mercury being considered the highest priority for multipathway analysis. Id. at Pg. ES-18. EPA did not evaluate the effects of HAPs on wildlife and particularly endangered species in this study, noting that this was not mandated by Section 112(n)(1)(A) of the CAA. Id. at Pg. ES-29. However, EPA admitted that further evaluation of ecological risks due to HAP emissions would be needed to fully evaluate the impacts of utility HAP emissions. Id.

108. No analysis was done in the Cumulative Assessment of the accumulation of mercury in the environment. In fact, the Cumulative Assessment stated:

> This study was unable to evaluate loading and long-term accumulation of heavy metals such as mercury in the environment. There is a potential for mercury to settle in water bodies and bioaccumulate and affect fish tissue for human consumption. Increase in soil concentrations of heavy metals over time from air deposition could not be evaluated in this study either. Jt. #11 at B-12.

109. The Cumulative Assessment also notes that "(i)t has been widely accepted that excessive Mercury loading into water bodies across the Nation is largely due to air deposition association with coal-fired power plants." Id. at E-15.

110. When Taylor was asked to compare TGS's permitted mercury limit to the amount of mercury emitted by all power plants in Kentucky in the year 2000, he found that TGS's permitted annual emission equals 12% of the total.

Experts' Opinions

111. In this Count, as with others, I am called upon to review and weigh the testimony of various experts, in light of their experience and credentials. The experts testifying on this Count, their background, and the facts supporting their opinions are as follows:

112. Dr. Westerman has either prepared or reviewed over 1,400 risk assessments. 2-20-04 TE at 53:1. He has done extensive research on biomagnification and bioaccumulation impacts of mercury on animals. 2-20-04 TE at 53:25-54:3.

113. Larry Taylor has 18 years of study and experience in environmental evaluation, environmental toxicology and risk assessment.

114. Dr. Poulson's expertise is with the Mammoth Cave ecosystem and the animals that inhabit it. He is not a risk assessor or toxicologist. As seen in Dr. Poulson's CV, he has authored many papers about the Cave's ecosystem. The NPS hired Dr. Poulson during the summers of 1992 through 1994 to work at the Park as a consulting ecologist. Between 1998 and 2003, Dr. Poulson was the lead organizer for the $5.2 million long-term ecological monitoring program at the Park, which involved "(v)irtually everything that could impact the cave, the river outside the cave and the forest, all the plants and animals." He indicated that the program involved pollution that comes from air pollution because "(a)nything that comes in the air can settle on plants, settle in the ground, into the water, get into the food chain and get into the cave because the water in the cave comes from outside the cave."

115. Dr. Fox is a registered environmental assessor, and she estimated she had prepared or reviewed over 100 risk assessments over the past 30 years. 2-9-04 TE at 6:2-4.

Dr. Poulson

116. Dr. Poulson opined that a risk assessment, such as the Cabinet's Cumulative Assessment, which only looked at inhalation and not at the food chain exposure pathway, should

not be given any credibility. 11-5-03 TE at 33. Dr. Poulson explained that for persistent toxic substances that bioaccumulate and biomagnify, such as the arsenic, lead, dioxin and mercury that will be emitted by TGS, the inhalation exposure pathway is relatively minor compared to the other exposure pathways such as eating food containing the toxic substances. Pollutants from TGC, such as sulfates, nitrates and mercury, combine to have a worse effect on animals and the ecosystem than those toxic substances would have individually. Dr. Poulson explained that the Park has some of the highest level of nitrates and sulfates of any national park in the country, Id. at 39 (referring to report of Bob Carson, scientist at the Park, P195, exh. 1).

Dr. Fox

117. Dr. Fox also explained why she believes the human health risk assessment in the Cumulative Assessment does not prove that TGS's pollution will not be harmful to the health and welfare of wildlife. First, humans are not necessarily the most sensitive species. Thus, the fact that the human risk assessment found no unacceptable impacts to humans does not mean that the same is true for wildlife. Second, Dr. Fox explained that the toxicology data is not necessarily obtained from studies performed on the most sensitive species. Thus, the safety factors that are used to account for the differences between humans and the laboratory animals that are the subject of toxicological studies are also needed to account for the differences between laboratory animal species and wildlife species. Dr. Fox explained that the human health assessment only looks at the inhalation exposure pathway and ignores other exposure pathways of critical concern to wildlife such as the dermal and food chain. Finally, Dr. Fox explained that there are significant biochemical differences between humans and certain wildlife species so that one can see toxic responses to certain chemicals, such as selenium, in wildlife that do not appear in humans.

Dr. Westerman

118. Dr. Westerman, stated that there is no way to identify what is the most sensitive species. Although DAQ did not know whether it actually had gotten the most sensitive species, it tried to address the problem by adding safety factors. Without doing the testing on every organism, Dr. Westerman opined that there would be no way to do otherwise. 6-15-04 TE at 19:9-22. Dr. Westerman further explained that the human protective threshold numbers are quite often based on animal studies. It is assumed that humans are more sensitive than animals. Therefore, the risk study begins with information based on animal studies and various safety factors are added to make the threshold more protective than what was considered protective for animals.

119. In response to Dr. Fox's and Dr. Poulson's testimony regarding exposure pathways, Dr. Westerman explained:

> the primary exposure route is going to be, for humans, plants, animals, of an air release is going to be inhalation. It's coming out of the air, so that's going to be the primary exposure factor. Part of the reason some of these other exposure factors, even for animals that are not such a big deal, is that inhalation is, I guess, a very direct route, if you may. Essentially we have nothing between this material going into the bloodstream but a very permeable membrane in the lungs. It's almost as if you took a syringe with a needle and injected the material, when you breath something in. 6-15-04 TE at 21:21 – 22:9.

Dr. Westerman went on to explain that with regard to dermal exposure to animals, for example, even burrowing animals have hair and skin which prevent a lot of material from getting into the organism. 6-15-05 TE at 22:9-17. Also, as to ingestion, Dr. Westerman clarified that because of the digestive tract, "quite a bit less of the percentage of what's actually in the food or the dirt ... will go across and actually get in the bloodstream." Id. at 22:24 – 23:2. In summary, Dr. Westerman testified that "… when you are inhaling this material, then quite often 100 percent of it goes across. So inhalation… is going to be the primary exposure route….” Id. at 23:7-9. Dr. Westerman testified that “Because … the numbers are so much lower than the human numbers, certainly Federal EPA wouldn't even think about wasting their time doing an ecological risk assessment.” 2/6/04 TE 31-32. Tom Adams stated that “(w)e had the information from the Cumulative Assessment which had as detailed of a risk as is done, certainly done in this state or done on the East Coast.” 4-14-04 TE at 91:17-21.

120. Dr. Westerman repeatedly said that the Cumulative Assessment looked at the predominant pathway, and that with the consideration of the safety factors involved and the extremely low level of emissions modeled from TGC, in his expert opinion, these concerns were addressed. 6-15-04 TE at 15-17. Dr. Westerman said safety factors in human health risk assessments usually add a 3,000 fold increase and that is enough to cover lack of ecological risk assessment that covers wildlife.

121. In contrast, PD3, a demonstrative exhibit by Dr. Poulson, and Dr. Poulson's testimony, said biomagnification can increase the risk to some wildlife by a factor of 1,000,000.

122. Dr. Westerman also addressed the issue of concerns about threatened and endangered species at the Park.

> Q: Are you concerned about the threatened and endangered species at Mammoth Cave with regard to emissions from the Thoroughbred plant?
>
> A: Well, not really. It's going to be quite a ways away from there. It's about 100 miles downstream[26]. It's proposed to be located ... northwest of the facility, and so the prevailing wind will not be blowing towards Mammoth Cave. I don't really see a way that it's readily going to be affected by that plant.

2-20-04 TE at 124:4-15.

[26] Dr. Westerman misspoke by indicating that the Park is some 100 miles from TGS. In fact, TGS will be located some 46 miles (74 km) west/northwest of the Park.

123. Dr. Westerman was also asked whether the modeling done for the Cumulative Assessment caused him concerns as to threatened and endangered species at the Park with regard to emissions from TGS. He responded:

> No, actually quite the opposite. It indicated that it wouldn't be a problem. We modeled out to 15 kilometers, and for the most part there was no problem. So I can't see why, if you went another 60, 70 miles away, that it would have an effect suddenly. Id. at 125.

COUNT 1 – Parties' Arguments

Petitioners

124. Petitioners point out that the Cabinet advances for the first time in this litigation the argument that the Cumulative Assessment, which contains an assessment of human health impacts, establishes that there will be no adverse impacts on animals. Petitioners maintain that the post hoc rationalizations of the Cabinet cannot serve as a sufficient predicate for its action. Prior to the litigation, the Cabinet did not advise the public that the Cumulative Assessment satisfied the risk evaluation requirements in 401 KAR 63:020, nor was the Cumulative Assessment a document which was noticed for public comment. Moreover, the Cumulative Assessment does not state that its human health inhalation is sufficient to serve as an evaluation of risks to animals. Indeed, the Cumulative Assessment states that "(e)ffects on ecological receptors were not evaluated." Jt. #11 at B-12.

TGC

125. TGC maintains that 401 KAR 63:020 does not require any specific method of evaluation. In addition to the Cumulative Assessment, which TGC argues is more than adequate, the NPS did not find any adverse impacts on species at the Park even though its scientists expressed concerns about TGS, and in addition, the modeling for TGS demonstrated compliance with the secondary NAAQS[27], which TGC urges are designed to be protective of ecological receptors as well as human health.

The Cabinet

[27] Petitioners point out that TGC's argument that NAAQS are protective of the environment because they are updated every five years is undercut by the fact that EPA is currently in violation of this requirement and is under a

126. The Cabinet points out that it has never interpreted 401 KAR 63:020 to require a *quantitative* ecological risk assessment in all cases. Indeed, the regulation does not require any specific method of evaluation. Thus, the Cabinet contends that its method of evaluation was consistent with 401 KAR 63:020. The Cabinet urges that it chose a rigorous quantitative method for evaluating human health risk and a qualitative approach to the evaluation of plants and animals. The Cabinet points out that although Dr. Poulson gave poignant testimony as to the dangers of biomagnification and bioconcentration and to the sensitivity of certain species at the Park, he is not a risk assessor or toxicologist, and he acknowledged that he has no expertise in modeling or special expertise with regard to mercury. 11-5-03 TE at 86. The Cabinet notes that Dr. Westerman, who has a doctorate in biology specializing in environmental toxicology, is well-qualified to exercise his professional judgment as to potential impacts on plants and animals. The Cabinet points out that even though Petitioners criticize the emphasis on inhalation as the primary route for the air emissions from TGS, Dr. Westerman explained that inhalation is the "primary pathway and big driver" according to EPA studies. 6/15/04 TE 45-46. Compared to inhalation, the other pathways have "very, very low impact". Id. Although Dr. Westerman never said that other exposure pathways are not relevant or important, he explained repeatedly that the Cumulative Assessment looked at the predominant pathway, and that with the consideration of the safety factors involved and the extremely low level of emissions modeled from TGS, in his expert opinion, these concerns were addressed through the Cumulative Assessment. 6-15-04 TE 15-17 (Westerman).

Court order to remedy the situation. American Lung Association, et al v. Whitman, C.A. 03-778 (ESH) (D.D.C.) (Consent Order entered July 3, 2003).

127. The Cabinet urges that it is reasonable to use the human RBSVs as an indicator of the potential impacts on ecological receptors. EPA has considered wildlife to be protected if its PRGs are satisfied, and the Cabinet's RBSVs are more conservative than PRGs. 2/20/04 TE 83, 139-40 (Westerman); 3/2/04 TE 219 (Taylor). Even assuming a potential for bioaccumulation and/or biomagnification, TGS's impacts are so negligible that Dr. Westerman is confident in his opinion:

> We're starting out with a number that has many orders of magnitude lower than an effect level, and you're still looking at an effect level, whether you're looking at bioaccumulation or otherwise. And the fact that we have used so many safety factors and even ended up less than 1/100 of that number as showing up anywhere in the area, I thought that ecological concerns were also addressed by that assessment. 6/15/04 TE 37-38; see also Id. at 44.

128. The Cabinet argues that its interpretation is consistent with the terms of the regulation and is also a practical interpretation of 401 KAR 63:020, which applies to all "affected facilities". Thus, it is not limited to the air permitting context. The Cabinet maintains that if it were required to conduct a quantitative ecological risk assessment for every "affected facility" in Kentucky, it would be an impossible task.

129. With regard to Dr. Fox's testimony that there are significant biochemical differences between humans and certain wildlife species and that toxic responses are found in certain chemicals, such as selenium, in wildlife that do not occur in humans, Dr. Westerman responded that "(p)articularly for some of these chemicals of environmental concern, the mercuries, the dioxins, the cadmiums, the PCBs, it appears that the toxicity is very, very similar across the board. Everything we test, it shows up about the same toxicity… basically all organisms do the same thing." 6-15-04 TE at 27:9-28:9.

130. In reply, Petitioners urge that TGC and the Cabinet have offered no document to support their theory that the study of the risks of inhalation exposure to humans found in the Cumulative Assessment should be accepted as a surrogate for an evaluation of impacts to animals. Petitioners point out that they proved there are sensitive species in the area and that Mammoth Cave biota are particularly vulnerable. Moreover, they proved that numerous government scientists and experts were concerned about mercury effects. See e.g., P8, the Helf report. They note that Kentucky is already under a statewide mercury advisory because of mercury levels in fish tissue. Jt. #11, Appendix I, p 1-4. Even the Cumulative Assessment states "(i)t has been widely accepted that excessive mercury loading into water bodies across the nation is largely due to air deposition associated with coal-fired power plants. Jt. #11, at E-15. Petitioners also point out that the Cumulative Assessment states that the study was unable to evaluate loading and long-term accumulation of heavy metals. Jt. #11 at B-12.

131. Petitioners reiterate Dr. Poulson's impressive credentials with regard to the Park and state that his opinion, based on decades of experience, boils down to the view that if one really wants to figure out whether the pollution from TGS will harm the animals in Mammoth Cave, one needs to look at the animals' exposure to those pollutants, especially persistent bioaccumulative pollutants, in the food chain and in the water. Dr. Poulson's opinion is that looking only at persistent, bioaccumulating pollutants in the ambient air is not useful in evaluating potential damage to wildlife in the Mammoth Cave ecosystem because the food chain and water play a much more dominant role in terms of delivering persistent bioaccumulating pollutants to wildlife in that ecosystem. 11-5-03 TE 33:6-34:1 and 87:15-90:1. Petitioners point out that the RBSVs are human health based and are for the inhalation exposure pathway only. 3-2-04 TE at 216:23-217:11; 218:13-17 (Taylor). Moreover, the Cabinet's decision not to evaluate

46 out of the 59 hazardous air pollutants emitted from power plants in the Cumulative Assessment was based on which contaminants are likely to contribute to human health risk. Hence, no consideration was given to whether wildlife, especially the sensitive, threatened or endangered species in the Mammoth Cave area, are likely to be put at risk by the 46 hazardous air pollutants that were not evaluated.

132. With regard to TGC's argument that ecological receptors will be protected because TGS's emissions will not violate the NAAQSs, Petitioners point out that there are no NAAQS for mercury, dioxin and the other persistent bioaccumulative chemicals. Thus, they urge that this argument is irrelevant. The superintendent at the Park in a letter dated April 27, 2001, to Ms. Andrews stated:

> There are nineteen vegetative species at Mammoth Cave NP that are very sensitive to ground level ozone concentrations. Vegetation and soils can be impacted by air pollution concentrations at or below the NAAQS. In addition, one of the purposes of the PSD program is to protect public health and welfare not withstanding attainment of the NAAQS. TGC22 at p.TB000867.

133. Petitioners also clarify that although the NPS stated that it lacked the ability to demonstrate an adverse impact on endangered species, P167 at 102 (Shaver depo.), the NPS clearly expressed reasons to be concerned.

134. In conclusion, Petitioners urge that they are not claiming that an ecological risk assessment is required in all cases. However, they emphasize that "this case is not all cases". The record is clear that TGS is one of the largest sources of pollution to request a permit in Kentucky in many years; that TGS is located within relatively close proximity to a very sensitive national park; and that numerous USFWS and NPS scientists expressed grave concerns that were never addressed in the permitting process. See e.g. P23, the February, 2002, letter from chief of

the EPA Region 4 Air Planning Branch, at p. 22, stating that "neither the permit application nor KDAQ's preliminary determination and statement of basis contains an assessment (qualitative or quantitative) assessing whether the proposed mercury emissions pose a risk of adverse impact on the ambient environment."

COUNT 1 - Conclusions

135. For the Cabinet to contend during this litigation, for the first time, that its responsibilities under 401 KAR 63:020 Section 3 were satisfied by the Cumulative Assessment amounts to a post hoc rationalization. Only when this issue was raised in this litigation did the Cabinet argue that its responsibilities under 63:020 were fulfilled by the Cumulative Assessment. However, the Cumulative Assessment was performed at the direction of the Governor and makes no reference to 401 KAR 63:020.

136. Our Kentucky Supreme Court recently discussed post-hoc rationalizations in Faust v. Com., 142 S.W. 3d 89 (KY 2004), in which it considered Faust's statutorily-granted reversion rights for employment within the classified service of state government. The Court stated "(w)e now learn from arguments before this Court that the Board felt constrained to give effect to Section 1(2) of 101 KAR 3:050, a regulation which attempted to implement the reversion procedures through application of the layoff statutes, despite the fact that neither KRS 18A.115(4) nor 18A.130(2) mentions layoffs.

> As a general rule, such post-hoc rationalizations are inappropriate, particularly as here, when virtually no basis in the record supports the Personnel Board's order. See Motor Vehicle Manufacturers Ass'n. State Farm Mutual Auto. Ins. Co., 463 U.S. 29, 50, 103 S.Ct. 2856, 2870, 77 L.Ed. 2d 443 (1983) (stating "(i)t is well-established that an agency's action must be upheld, if at all, on the basis articulated by the agency itself"). 142 S.W. 3d at 98.

See also American Textile Mfrs. V. Donovan, 452 U.S. 490, 539 (1981), where the U.S. Supreme Court held that "post hoc rationalizations of the agency or the parties to this litigation cannot serve as a sufficient predicate for agency action."

137. Aside from the issue of post hoc rationalization by the Cabinet, it appears that 63:020 has been largely overlooked by DAQ. Dr. Westerman candidly testified that the Risk Assessment Branch has never been asked to do either a human health risk assessment or an ecological risk assessment for a PSD permit. Moreover, Dr. Westerman never stated that the Cabinet did a *qualitative* assessment of the ecological impacts of TGS, as Cabinet counsel now argue. In fact, he repeatedly explained that in preparation of the Cumulative Assessment "…we didn't look at ecological effects of any of the chemicals…" 2-6-04 TE 47:15-16.

138. As argued by Petitioners, this is not just any case. TGS is one of the largest sources of pollution to request a permit in Kentucky in many years; TGS is located within relatively close proximity to a highly significant cave and karst area, Mammoth Cave National Park; and numerous USFWS and NPS scientists expressed concerns that were not addressed in the permitting process. Mammoth Cave Park scientist Kurt Helf's paper states in its introduction:

> The proposed thoroughbred Generating station (TGC) is a potentially large source of mercury (Hg) deposition on South Central Kentucky Karst (SCKK) ecosystems. Indeed, according to Peabody's own estimates TGS will be the fourth largest Hg emitter in the state of Kentucky (Table 1)[28]. Because prevailing winds tend to blow northeast[29], TGS would likely have the second largest impact in the state, in terms of Hg deposition, on SCKK ecosystems. Currently little data are available that would enable researchers to predict the effects of such a large increase in Hg deposition on SCKK ecosystems.

P195, exh. 3 at 1.

[28] Table 1 shows the largest Hg emitting plants to be: 1 – Paradise Fossil Plant (Muhlenberg); 2- Big Sandy (Lawrence); Ghent (Carroll); and TGS (Muhlenberg). Paradise and TGS are in close proximity.

It is not disputed that the karst geology in the area of the Park is especially vulnerable to pollution from TGS. This is because water on the surface directly enters the groundwater through sinkholes without the filtering that occurs in non-karst areas. 11-5-03 TE at 122:9 (Dr. Groves). An inhalation impact study does not consider concentrations of pollution in water. As Dr. Poulson explained, there are animals in the Park which are long-lived and susceptible to biomagnification and bioaccumulation. This is exactly what the Cumulative Assessment clearly stated it did not study. As stated earlier, P107-5 states that for HAPs that are persistent and/or bioaccumulate, the non-inhalation exposure pathway could be more important than the inhalation pathway. EPA identified four high priority HAPs (radionuclides, mercury, arsenic, dioxins) to assess for non-inhalation exposures. Id. at ES-4.

139. Moreover, certain statements in the Cumulative Assessment stand in stark contrast to Dr. Westerman's reliance on the human health inhalation evaluation as being a sufficient indication that TGS does not pose an unacceptable risk to animals. These statements include the acknowledgement that the Cumulative Assessment did not evaluate loading and long-term accumulation of heavy metals such as mercury in the environment or the increase in soil concentrations of heavy metals over time from air deposition, although it notes the potential for mercury to settle in water bodies and bioaccumulate and affect fish tissue for human consumption. The Cabinet and TGC produced no document supporting Dr. Westerman's opinions that a consideration of the inhalation pathway alone (without considering the food chain exposure pathway) is sufficient to determine that there will be no harmful effects on plants and animals from TGS.

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[29] It appears that Dr. Westerman and Helf may not agree about whether prevailing winds are in the direction of the Park.

140. Respondents urge that 401 KAR 63:020 Section 3 confers discretion on DAQ in choosing a methodology for each individual case, given the breadth of the reach of the regulations to all "affected facilities". They argue that the methodology is left to the professional and technical judgment of the Cabinet as long as it has a rational basis for its methodology. I do not disagree. However, the choice of a methodology would need to be based on the type of facility and other relevant factors, among which would be the location of the facility. I am mindful that the experts at the Cabinet's Risk Assessment Branch were satisfied that the findings and analyses of the Cumulative Assessment were sufficient to comply with 401 KAR 63:020. DAQ's engineering consultant, Tom Adams, came to the same conclusion. 4-14-04 TE at 89-90. They all testified that the methodology documented in the Cumulative Assessment supports the conclusion that other ecological receptors are protected, as is human health. 2-20-04 TE at 92-94 (Westerman). Dr. Westerman also stated that this conclusion includes the potential for biomagnification and bioaccumulation because the modeled values were so far below the screening values. 6-15-04 TE at 37-38, 44-45.

141. In spite of these opinions, I conclude that the Cumulative Assessment cannot be considered adequate when it did not consider the food chain and water which play a much more dominant role in terms of delivering persistent, bioaccumulating pollutants to wildlife in the Park and the South Central Kentucky Karst ecosystem.

142. Where there is already a mercury advisory in Kentucky, where it is widely accepted that mercury loading in the environment comes largely from power plants, where there are vulnerable species and concerns from government scientists and other researchers about the effect of mercury from TGS on those species, and where TGS will contribute an additional 12% of mercury to existing sources, it was incumbent on the Cabinet to specifically evaluate the

effect of that loading on ecological receptors. To determine whether the pollution from TGS will harm the animals in the Park, the animals' exposure to those pollutants must be specifically studied, especially persistent bioaccumulative pollutants, in the food chain and in the water. This is because abiotic contaminants are transferred from the ambient environment into fauna at the greatest rates through the consumption of food and water.

143. Hence, I recommend that the Cabinet evaluate the impact of TGS' potentially hazardous or toxic substances on animals.

COUNT 2 – Public Participation

COUNT 2 – Findings

Overview

144. Count 2 involves Petitioners' contention that the Cabinet failed to make certain information available to the public during the permitting process. There are four areas in which Petitioners argue that the public participation requirements were not met:

Area 1: Public comment periods - making relevant information available;

Area 2: Public notice - providing the correct increment consumption and information about the FLM's finding of potential adverse impact;

Area 3: SOB - explaining the legal and factual basis for the permit conditions; and

Area 4: Public comments - responding to public comments.

145. TGC maintains that the public participation regulations were fulfilled because the process allowed the public a meaningful opportunity to participate.

146. The Cabinet, while acknowledging that there were some very minor, insignificant discrepancies in the public notice, contends that they had no impact on Petitioners' due process rights to be informed about the TGC permitting process.

General Findings

The following facts set forth certain events as they relate to the public participation involved with the permitting process.

147. There are three versions of the permit and an SOB with each:

> *the first SOB, Jt. #3, which was issued with the first draft permit, issued on December 28, 2001, Jt. #2;
>
> *the second SOB, Jt. #5, which was issued on June 19, 2002, in conjunction with the second draft permit, Jt. #4, and the public notice issued on the same date, Jt. #24; and
>
> *the third SOB, Jt. #7, which was released after the public comment period and with the final permit on October 11, 2002, Jt. #6.

148. The first public hearing was held on February 12, 2002, as announced in a public notice published on January 9, 2002.

149. On February 14, 2002, the FLM provided comments on the first draft permit and found that the proposed emissions would have an adverse impact on visibility and could potentially affect federally listed threatened and endangered species at the Park. P167 (Shaver depo.), exh. 28, p 1. This adverse impact finding was based on modeling done at the 0.167 lbs/MMbtu SO_2 rate. P167-28 at NPS 003428. In its February 14^{th} letter, the FLM stated that it had received a summary of a new modeling analysis prepared by consultants retained by the permit applicants which suggests there may be no adverse impact on visibility at the Park. However, the FLM did not have time for a thorough review of the new modeling analysis prior

to the end of the (first) public comment period. For this reason, the FLM stated that based on its review and analysis of DAQ's preliminary determination, "we believe that these proposed emissions would have an adverse impact on visibility and could potentially affect federally listed threatened and endangered species" at the Park. Id.

150. On June 19, 2002, public notice was published announcing the July 25, 2002 second public hearing. Jt. #24; Cab18. The public notice provided the following information regarding this finding of adverse impact and DAQ's response to the finding:

> On February 18, 2002, the Division received notification from the United State (sic) Department of the Interior (DOI), that based on their review and analysis of material received on January 2, 2002, they believed that the proposed emissions from Thoroughbred Generating would have an adverse impact on visibility at Mammoth Cave National Park. Subsequent modeling provided to DOI and the Division demonstrated that there would be no impact greater than 10% on any day over a three year period, and only 2 days greater than 5% over that period. Based on this analysis, the Division does not concur that Thoroughbred Generating would have an adverse impact on Mammoth Cave National Park.

151. The "subsequent modeling" referred to in the June 19 public notice was still based on the 0.167 lbs/MMbtu rate. This is known because the modeling for the short term SO_2 0.41 lbs/MMbtu emission rate was not submitted to DAQ until July 24, 2002, over a month after the public notice was sent out and the day before the public hearing on July 25, 2002. See Jt. #23 and 1-6-04 TE at 127:23-131:1(Handy). At the public hearing, it was announced that the comment period would be extended through August 24, 2002, in order to allow for additional comments on the new short term SO_2 emission rate of 0.41 lbs/MMbtu. Cab18. The extension of the comment period was not published in the newspaper.

152. Also, Jt. #21, TGC's narrative about the ambient air impacts for the 0.41 lbs/MMbtu 24 hour SO_2 limit was not submitted until August 9, 2002, after the public hearing,

and shows that at the 0.167 lbs/MMbtu emission rate there would be no impact on visibility greater than 10% on any day over a three-year period, and only 2 days greater than 5% over that period. Jt. #21 at pg. 2 of 8.

153. However, at the 0.41 lbs/MMbtu rate, the preliminary results of the modeling showed that the days of impacts above 10% would be 2 days in a three-year period, which compares to the public notice that told the public there would be no days over 10%. Jt. #22, page 1. As to days of impacts over 5%, the results showed up to 21 days over a three-year period. Jt. #22, page 2. See also P100-4 at ET000572. These 21 days compare to the only 2 days that the public was told about in the public notice. Jt. #24.

154. In a comparison of the June 19, 2002 public notice, Jt. #24, with the SOB, Jt. #5 at 24, which was issued with this public notice, there are some differences regarding increment consumption. Increment is the additional ambient air pollution above the baseline that the proposed major source of air pollution will cause. 401 KAR 52:100 Section 5(10) and 40 CFR 51.166(q). The numbers highlighted and marked with an asterisk in the following charts show the differences. Jt. #24 vs Jt. #5, p 24, table 6.3. The increment consumption figures in the public notice of June 19, 2002, are for the increment that will be consumed in Muhlenberg County based on a 30-day SO_2 emission rate of 0.167 lbs/MMbtu.

155. The June 19, 2002 public notice listed the following predicted increment consumption:

Pollutant	**Averaging Period**	**Class II PSD Increment** ($\mu g/m^3$)	**Applicant's Class II Increment Consumption** ($\mu g/m^3$)

PM_{10}	Annual 24-hour	17 30	1.69 8.17*
SO_2	Annual 24-hour 3-hour	20 91 512	1.57 20.95* 112.4
NO_x	Annual	25	0.76*

(The above increment consumption numbers listed in the public notice are identical to those contained in a fax from Bryan Handy to Ben Markin, Cab22.)

156. The SOB which was issued with the June 19, 2002, public notice contains the following increment consumption numbers:

Pollutant	**Averaging Period**	**Class II PSD Increment** (µg/m^3)	**Applicant's Class II Increment Consumption** (µg/m^3)
PM_{10}	Annual	17	1.69
	24-hour	30	8.86*
SO_2	Annual	20	1.57
	24-hour	91	27.76*
	3-hour	512	112.40
NO_x	Annual	25	0.697*

157. TGS will also consume increment in at least Christian, Daviess, Ohio and Webster counties. Jt. #7 at 33.

158. The public notice did not report the degree of increment that TGS will consume in the Class I area in the Park, even though TGC's expert, Scire, claimed that TGC would consume 99.6% of the allowable Class I 24-hour SO_2 increment. P100-4 at 2, Table 3 (4.98 µg/m^3 consumed out of available 5 µg/m^3).

159. On August 22, 2002, the FLM sent a letter to DAQ withdrawing its adverse impact finding of February 14, 2002, on the basis that a new modeling analysis from TGS, which was verified by the FLM's staff experts, suggested that there would be no adverse impacts on visibility at the Park. In addition, the August 22, 2002 letter stated:

> KDAQ's revised preliminary determination and draft PSD permit for the TGS facility now includes a 24-hour sulfur dioxide (SO_2) limit of 0.45 lbs/MMbtu, in addition to the 30-day rolling average limit of 0.167

> lbs/MMbtu. We understand that TGS has agreed to lower 24-hour SO_2 limit of 0.41 lbs/MMbtu in order to comply with short-term air quality standards and increments. We conducted an air quality modeling analysis of the 0.41 lbs/MMbtu limit and found **potential adverse impacts on visibility** at Mammoth Cave National Park at that level. We assessed alternative limits and found that at the 0.23 lbs/MMbtu level there would be no adverse impacts on visibility at Mammoth Cave National Park. (emphasis added). Jt. #19.

160. The public was not notified via a public notice of the FLM's August 22, 2002 finding of "potential adverse impacts".

161. None of the SOBs provide documentation or explanation of the following:

a. Elimination of IGCC and CFB from the BACT analysis
b. Feasibility of achieving a NO_x limit of less than 0.08 lbs/MMbtu over a 30-day average
c. Percentage removal for TGS's SCR
d. Ozone modeling done for the Cumulative Assessment
e. Basis for TGC's failure to conduct preconstruction monitoring for ozone
f. Explanation for how the mercury limit is more stringent than the best controlled similar source
g. Explanation for why emissions rates were not established based on use of a baghouse or fabric filter
h. Discussion of SO_2 short term increment and NAAQS consumption determinations based on 24-hour SO_2 emission limit of 0.41 lbs/MMbtu
i. Discussion of whether TGS's hazardous emissions will harm humans or animals.

162. On April 17, 2002, DAQ produced *draft* responses to comments, which were followed on May 14, 2002, with the final version of responses received during the public comment period. Jt. #39 and 43. On October 11, 2002, DAQ produced its final responses to comments. Jt. #63. The final responses to comments were issued with the final SOB and the permit on October 11, 2002.

163. In the third SOB, the 24-hour SO_2 increment consumption in Muhlenberg County was listed as 53.8 $\mu g/m^3$.

COUNT 2 – Parties' Arguments Followed By Conclusions[30] on the Four Areas of Count 2

Area 1 -Public Comment Periods –

Making Relevant Information Available

164. Petitioners urge that certain critical supporting information was not made available during the public comment period as required by 401 KAR 51:017, Section 16; 401 KAR 52:100 Sections 5(11) and 8(1); and 40 CFR 51.166(q)(2).

165. The public comment period begins on the date the public notice is published in the newspaper and ends 30 days after the publication date. 401 KAR 52:100 Section 2(2)(a)(b).

166. The regulations Petitioners rely on are as follows, with relevant portions in bold:

> <u>401 KAR 51:017, Section 16 Public Participation.</u>
>
> The cabinet shall follow the applicable procedures of 401 KAR 52:100 and 40 CFR 51.166(q) in processing applications under this administrative regulation.
>
> <u>401 KAR 52:100 Section 5, Information Included in the Public Notice</u>
>
> Subsection (11), Name, address, and telephone number where interested persons may obtain the following information:
>
> …
>
> (b) **Relevant supporting material, including permit application, permits, compliance plans, and monitoring and compliance certification reports, except for confidential information;**
>
> …
>
> <u>401 KAR 52:100 Section 8, Public Inspection of Documents</u>
>
> Subsection (1), Public Inspection of Documents
>
> (1) **During the public comment period, the cabinet shall make available** for public inspection **all information**, except that which is confidential, contained **in the**:
>
> (a) Permit application;
>
> (b) Draft permit; and

[30] Since this Count has multiple subparts, my conclusions will follow the parties' arguments on each subpart.

(c) **Supporting materials.**

40 CFR 51.166(q)(2) requires that the Cabinet:

(ii) **Make available in at least one location** in each region in which the proposed source would be constructed a copy of all materials the applicant submitted, a copy of the preliminary determination, and **a copy or summary of other materials, if any, considered in making the preliminary determination.** (Emphasis added)

Petitioners

167. In their argument about the public availability of all supporting materials, Petitioners make several specific arguments about material which was not available during the public comment period from June 19, 2002 to July 25, 2002:

* the air modeling for the final SO_2 short-term limit of 0.41 lbs/MMbtu;

* the sulfur content of the design basis coal to be used at TGS; and

* certain standard operating procedures (SOPs) and manufacturer's specifications that will be used to help determine compliance with the permit provisions.

Each of these issues will be discussed separately.

A. Air modeling for the 0.41 lbs/MMbtu SO_2 short term limit

Petitioners

168. Petitioners urge that one of the most important pieces of information not available to the public during the comment period was the modeling for SO_2 increment and NAAQS at the final short term SO_2 emission rate of 0.41 lbs/MMbtu based on a 24-hour averaging time. This modeling was not provided until July 24, 2002, over a month after the final comment period started on June 19, 2002, and only one day prior to the public hearing on July 25, 2002. TGC submitted a narrative about the ambient air impacts for the 0.41 lbs/MMbtu 24 hour SO_2 limit to

the Cabinet on August 9, 2002. Jt. #21. Thus, this information was not made available until after the second, and final, pubic hearing.

Cabinet

169. The Cabinet urges that the 24-hour 0.41 lbs/MMbtu SO_2 limit was never intended to be a BACT limit for SO_2, but instead, the Cabinet decided to add the 24-hour 0.41 lbs/MMbtu SO_2 limit to the permit as an additional safeguard to ensure protection of visibility. Also, the Cabinet points out that the public already had the air dispersion modeling for the prior 24-hour SO_2 limit of 0.45 lbs/MMbtu. Thus, if the public had any comments regarding the air dispersion modeling for the 24-hour SO_2 limit, the public would have raised those concerns based on the modeling for the 0.45 lbs/MMbtu SO_2 limit, which was less protective of human health and the environment than the 0.41 limit.

TGC

170. TGC points out that 401 KAR 52:100, Section 8(1) provides that supporting materials must be made available "during the public comment period", not at the beginning of the public comment period. The second public hearing on the TGC permit was held on July 25, 2002. Thus, the required modeling information, which was submitted on July 24, 2002, was available at the time of the public hearing. DAQ extended the public comment period an additional 30 days after the public hearing to allow for additional comments on this very issue. Cab18 at 2 (public hearing transcript); TGC18 (letter dated July 23, 2002 to IDEM and Valley Watch stating that a final resolution of the 24-hour SO_2 limit issue is expected prior to the July 25 public hearing and also stating that DAQ is extending the public comment period to August 24 so that this additional information can be made available to the public). In addition, TGC submitted an analysis supporting the original short-term limit of 0.45 lbs/MMbtu prior to June

19, 2002, the start of the second public comment period. Jt. #26. Also, this analysis was explained in the Revised Preliminary Determination and SOB, released to the public with the June 19, 2002 Public Notice. Jt. #5 at 23. So, TGC maintains that the public had all the information supporting the less stringent 0.45 lbs/MMbtu rate at the start of the public comment period.

Petitioners' Reply

171. In reply, Petitioners urge that the Cabinet is required to make all supporting materials available during the *entire* public comment period. Although they admit that the 0.41 lbs/MMbtu modeling was on Don Newell's computer at DAQ by 12:55 p.m. on July 24, 2002, Jt. #23, and a preliminary summary of the impacts on visibility at the Park was sent to the Cabinet sometime after 5:40 p.m. on July 25, 2002, Jt. #22, they urge that this does not equate to making the information available to the public as required by the regulations. In addition, the final results of the visibility analysis were not available to the public until after the July 25, 2002, public hearing. They appear to have been received by the Cabinet on August 9, 2002. Jt. #1.

172. Even though DAQ purported to extend the public comment period until August 24, 2002, Petitioners point out that there was no notice in the newspaper explaining that the public comment period was extended and no mailing was sent to all of the interested parties. They urge that when notice is required to be placed in the newspaper, providing notice via another means does not absolve the agency of its duty to abide by the regulation. Moreover, the final information was available no sooner than August 9, 2002. Jt. #21. Thus, even with an informal extension of the public comment period, the public was never given 30 days to evaluate the modeling at the 0.41 lbs/MMbtu rate.

173. In reply to TGC's claim that the Cabinet complied with the spirit of the law by providing the public with the analysis of impacts at the 0.45 lbs/MMbtu emission rate, Petitioners state that the "analysis" at the 0.45 lbs/MMbtu emission rate was not computer modeling but was a simplistic extrapolation based on a methodology that TGC and its consultants created. Jt. #26 and Jt. #5 at 23. Indeed, EPA and the Cabinet rejected this nonmodeling methodology and insisted that TGC submit modeling to support its short term SO_2 emission rate. 1-9-04 TE 16:15-21 (Handy). Thus, Petitioners contend that all that existed during the public comment period was an invalid nonmodeling analysis for the 0.45 lbs/MMbtu emission rate. The modeling analysis submitted after the public comment period began showed that the nonmodeling analysis was incorrect. The modeling analysis showed that at the 0.45 lbs/MMbtu emission rate, TGS would violate the Class I 24 hour SO_2 increment. In Jt. #23 at page 1 of "Summary of Short-Term Limit Run", Table 3, the modeling shows an impact in Year 1992 of 5.3 $\mu g/m^3$ when the allowable increment is only 5 $\mu g/m^3$. Thus, this nonmodeling methodology which was rejected by EPA and the Cabinet actually misled the public into thinking that the 0.45 lb/MMbtu emission rate would not cause TGS to violate the Class I increment, when in reality it would.

174. Petitioners urge that while the public now knows that at the 0.45 lbs/MMbtu emission rate, TGS will violate the Class I increment, the public was never afforded a meaningful opportunity to determine whether the inputs into the 0.41 lbs/MMbtu modeling were correct or to hire their own modeler to re-run the 0.41 lbs/MMbtu modeling with the correct inputs. Not only did the Cabinet fail to make the modeling available, the Cabinet failed to provide the increment consumption figures in the public notice and the SOB which would have alerted the public to this issue early in the process.

Conclusions on air modeling for the 0.41 lbs/MMbtu SO_2 short term limit

175. This argument can be boiled down to the fact that the modeling for the short term SO_2 emission rate of 0.41 lbs/MMbtu was not available until a day before the public hearing and the analysis was not available until August 9; however, the modeling for the less stringent limit of 0.45 lbs/MMbtu was available, although Petitioners urge this was an invalid nonmodeling analysis which showed that at the 0.45 lbs/MMbtu rate TGS would not violate the Class I increment, when in reality it would.

176. In an order of the US EPA's Environmental Appeals Board (EAB), In the Matter of Old Dominion Electric Coop., 3 E.A.D. 779, 1992 WL 92372, denying a request to review a PSD permit, the Environmental Appeals Board was presented with similar arguments. In response to EPA Region 3's comments on the draft permit, the permit applicant tightened its emission limits. The state revised the permit and issued it without soliciting further comment from the public. Petitioners argued that the state should have solicited further comment on the revised modeling. The EAB did not agree:

> (I)t is self-evident that Petitioners are in no position to oppose the decision to tighten the permit's SO_2 emissions. Petitioners are not worse off with the revision than without it. Moreover, there is no reason to believe that tightening the emissions limitation is likely to result in unanticipated adverse environmental consequences in comparison with retention of the previous, less stringent emissions limitation. The revised permit by all accounts is a logical outgrowth of the notice and comment process and all commenters have had a fair and reasonable opportunity to present their views on the permit. P. 12 of 18.

177. Here, Petitioners cannot deny that they are in a better position with the 0.41 emission rate than they were with the less stringent 0.45 short term SO_2 emission rate. Indeed, the harm Petitioners urge they suffered in not having the modeling and analysis at the beginning of the public comment period is that they were denied a meaningful opportunity to determine

whether the inputs into the 0.41 lbs/MMbtu modeling were correct or to hire their own modeler to re-run the 0.41 lbs/MMbtu modeling. However, Petitioners give no reasons why any member of the public who was concerned with the 0.45 limit would not have attended the public hearing on July 25, at which time they would have been advised that the public comment period was being extended through August 24 to receive comments regarding the new limit. Indeed, Don Newell announced at the public hearing the reason for the extension, and John Blair, president of Petitioner Valley Watch, was present and spoke at the public hearing. Cab18 at 2 and 44. There is every reason to think pursuant to the letter dated July 23, 2002, to IDEM and Valley Watch from DAQ Director Lyons, that DAQ did consider the modeling for the 0.41 limit to be "supporting material" which it was required to make available during the public comment period. TGC18. This is the very reason for the extension of the public comment period. The letter does suggest that DAQ believes that "supporting material" should be available for the entire public comment period, as Petitioners urge, because the extension was for an additional 30 days. However, I conclude that the public was not denied an adequate opportunity to review the new modeling and analysis even though another public notice was not published announcing the extension.

B. Sulfur Content of the Design Basis Coal

Petitioners

178. Another piece of information Petitioners urge that the Cabinet did not make available to the public during the comment period was the sulfur content of the design basis coal, which is critical information in assessing the SO2 BACT determination.

Conclusions on sulfur content of the design basis coal

179. I conclude that this argument is refuted by the coal quality data, including the sulfur content of the coal, as provided in the revised application submitted on October 26, 2001, Jt. #57 at Red 36, and in TGC's responses submitted on December 12, 2001, Jt. #56 at Red 42-44, in which TGC provided coal quality data, including the sulfur content of the coal.

C. Manufacturer's Specifications and SOPs

Petitioners

180. Petitioners urge that the Cabinet never provided the public with manufacturer's specifications and/or SOPs although the permit requires that all pollution control equipment, including the SCR, dry ESP, wet FGD, wet ESP, partial enclosures, bin filters, chutes, baghouses and other control equipment, as well as the boiler and coal piles, is to be operated to maintain compliance with permitted emission limits in accordance with manufacturers' specifications and/or standard operating practices. They cite to 401 KAR 50:016, Section 1(1) which incorporates by reference: "Policy Manual of the Division of Air Pollution Control, May 15, 1985", providing that a PSD permit shall not be issued until certain design specifications are submitted. Petitioners cite to a recent US EPA Administrator's Order, In Re: Cargill, Inc., Petition IV-2003-7 (July 16, 2004), in which the applicant was directed to revise certain conditions of the permit to provide a specific citation for the manufacturer's specifications and to make such specifications part of the permit record. Id. at 14.

Cabinet

181. The Cabinet acknowledges that it did not make the manufacturers' specifications and/or SOPs for several emissions units and air pollutant control equipment units available to the public. However, it maintains that it cannot be required to do so based on the Cargill order which was not available prior to the issuance of the permit on October 11, 2002.

TGC

182. TGC states that this claim has not been raised before or during the formal hearing and points out that due to Kentucky's combined (PSD) construction and (Title V) operating permit, the Cabinet must issue one permit that establishes operating parameters before it knows what the appropriate operating ranges should be. Ms. Andrews, assistant director of DAQ, addressed this situation:

> A: In our situation now, since with the merged program you have no operating history of the facility, you're really handicapped in developing actual ranges and acceptable limits for your parametric monitoring.
>
> Q: So how does the division address this problem?
>
> A: We've had to … what's in the permit is fairly generic or general, maintained or controlled equipment within your manufacturer's specifications.
>
> 2/19/04 TE 159:2-13.

Adams explained that once the facility is operational and the SOPs are known, DAQ re-evaluates the monitoring approach to ensure the permit reflects appropriate operating parameters. 4/16/04 TE 47; 4/15/04 TE 90; 4/14/04 TE 109.

183. TGC distinguishes the Cargill order by pointing out that the permit in Cargill was a state operating permit issued by Georgia's Environmental Protection Division pursuant to Title V of the CAA. The emissions unit at the facility was already constructed and had been in operation for almost 22 years prior to the original issuance of the Title V permit. Therefore, appropriate SOPs and manufacturer's specifications had been developed over the course of 22 years and EPA held that such information should have been included in the permitting record.

184. The Cabinet and TGC point out that the Policy Manual at 2-11 states that "not all information may be available in all cases" and that "information requirements should be adjusted

to fit the circumstances of the applicant at the time of the permit application". The Cabinet also urges that Petitioners offered no evidence during the hearing that the absence of any of the items listed in Table 2.1 of the Policy Manual (information to be included in applications for coal-fired power plants) caused DAQ's BACT determination to be insufficient.

185. TGC also points out that the Policy Manual also states at 2-13 that "(t)he source must provide enough information to demonstrate that the proposed control equipment will adequately reflect BACT and applicable ambient air quality standards and PSD increment will not be exceeded." TGC submitted multiple design specifications to DAQ, such as coal design information, Jt. #56 at Red 41-44, and specific design specifications for the control technology. Jt. #44 at Red 58-129. With regard to design specifications for the SCR, information was provided regarding the percentage removal for the entire NO_x control system. Jt. #57 at Red 236.

Petitioners' Reply

186. In reply, Petitioners cite to Minnesota Center for Environmental Advocacy v. Minnesota Pollution Control Agency, 600 N.W. 2d 427, 435 (Minn.. App. 2003), as support for their general position. In that case, the court found that the fact that the public was not given an opportunity to review and submit comments on the Storm Water Pollution Prevention Plan (SWPPP), which is to be developed and submitted to the state agency in its application for a general permit for municipal separate sewer systems water discharges (NPDES-National Pollutant Discharge Element System), was a violation of the public participation requirements.

Conclusions on manufacturer's specifications and SOPs

187. I do not find the Minnesota case persuasive. In the Minnesota case, SWPPPs are referred to as the "core" of the general permit, i.e. they contain the substantive details for storm water control and substantive information on how small municipalities will comply with the

Clean Water Act. In contrast, here, the combined permit initially provides that all equipment is to be controlled in accord with manufacturer's specifications and later DAQ re-evaluates the monitoring approach to ensure the permit reflects appropriate operating parameters. This is not a situation where the manufacturer's specifications and operating parameters were known and not revealed to the public.

188. Petitioners did not raise the Cabinet's alleged failure to comply with the Policy Manual prior to the formal hearing or even during the formal hearing, and for that reason alone, it will not be considered at this point. However, I conclude that with Kentucky's merged program where a combined PSD construction and Title V operating permit are issued, the current practice as explained by Andrews and Adams is not only the only workable practice but is in keeping with the Manual.

Area 2 - Public Notice

189. Petitioners urge that the public notice was missing information and contained incorrect information about how much increment would be consumed by TGS in violation of 401 KAR 52:100 Section 5(10) and 40 CFR 51.166 (q)(2)(iii).

190. Petitioners also argue that the public notice violated 401 KAR 51:017 Section 15(3) by failing to inform the public of the FLM's finding of a potential adverse impact.

191. Each of Petitioners' public notice claims will be discussed separately.

A. Increment information

401 KAR 52:100, Public, affected state, and U.S. EPA review
Section 5, Information Included in Public Notice
Subsection (10) For permits subject to review under 401 KAR 51:017 (PSD), **the degree of increment consumption expected to occur**;

40 CFR 51.166(q)(2)(iii) likewise provides:

> (iii**) Notify the public**, by advertisement in a newspaper of general circulation in each region in which the proposed source would be constructed, of the application, the preliminary determination, **the degree of increment consumption that is expected from the source** or modification, and of the opportunity for comment at a public hearing as well as written public comment. (Emphasis added).

Petitioners

192. Petitioners point out that the public notice of June 19, 2002, Jt. #24, did not provide the following:

> *the degree of Class I increment TGC will consume in the Class I airshed in the Park;
>
> *the Class II SO_2 increment for Christian, Daviess, Ohio and Webster Counties; and
>
> *the SO_2 increment TGC will consume for the 24-hour and 3-hour increments in Muhlenberg County based on the final permitted emission rate of 0.41 lbs/MMbtu over a 24-hour averaging time. [31]

Cabinet

193. The Cabinet acknowledges that a few of the increment consumption numbers listed in the June 19, 2002, public notice Jt. #24 were inconsistent with the increment consumption numbers which went out in the SOB, Jt. #5, which was issued with the June 19, 2002, public notice. The Cabinet urges that the differences are inconsequential, however, as demonstrated by the charts in the Findings and comparisons below, and as demonstrated by a lack of any mention of the increment consumption numbers in the public notice by any of the persons who submitted public comments or who spoke at the July 25, 2002, public hearing. Cab18.

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[31] Petitioners alleged in their initial post hearing brief that the public notice "appears" to have misstated the amount of PM_{10} increment that will be consumed. However, they do not clarify this allegation in their reply brief and stated that they will not further address this issue.

194. The Cabinet makes the following comparisons and points out that even with the errors the increment being consumed is considerably below the allowable increment, and thus, the Cabinet urges the error is insignificant.

*The error in the public notice underreported the 24-hour PM_{10} increment consumption by 2.3%; the allowable 24-hour PM_{10} increment consumption is 30 $\mu g/m^3$.

*The error in the public notice underreported the 24-hour SO_2 increment consumption by 7.4%.[32] The allowable 24-hour SO_2 increment is 91 μg/m^3.

*The error in the public notice over reported TGC's annual NO_x increment consumption by 0.25%; the allowable annual NO_x increment consumption is 25 μg/m^3.

195. The Cabinet contends that Class I increment consumption numbers are not required by 401 KAR 52:100, Section 5(10) and 40 CFR 51.166(q)(2)(iii) because neither regulation requires the inclusion of both the Class II and Class I increment consumption numbers. The Cabinet maintains that the NPS and the FLM are the audience for the Class I increment consumption numbers.

TGC

196. TGC responds, in summary, by urging that the public notice complied with the letter of the law by adequately fulfilling its purpose of giving interested parties a meaningful opportunity for public comment. TGC notes that 401 KAR 52:100 Section 5(10) requires that the public notice include the "degree of increment consumption expected to occur as a result of TGS's emissions." Even assuming that the increment consumption represents only the increment consumed in Muhlenberg County, which TGC maintains is the area of TGS's highest impact, Petitioners offer no authority showing that the decision to provide the worst case increment consumption projections for Muhlenburg County would frustrate the purpose of the public notice.

[32] Petitioners point out in their Reply Brief that the 24-hour SO_2 Class II increment consumption in Muhlenberg County was based on the 0.167 lbs/MMbtu emission rate, not 0.45 lbs/MMbtu rate as the Cabinet states in its brief.

197. TGC notes that the parties agree that the final short term SO_2 limit was not developed until after the second public notice. Because petitioners have not proven that increment consumption based on a short term SO_2 emission rate of 0.41 lbs/MMbtu "is expected to occur" (quoting 401 KAR 52:100 Section 5(10)) on a continual basis (which would violate the 30-day SO_2 limit of 0.167 lbs/MMbtu), TGC urges it was reasonable for DAQ not to include increment numbers based on a 0.41 lbs/MMbtu emission rate.

Petitioners' Reply

198. In reply, Petitioners urge that the Cabinet's failure under 401 KAR 52:100 Section 5(10) to inform the public of the amount of increment TGS will consume is a straightforward issue that requires that a new public notice be issued containing a variety of increment consumption figures which were missing, including the highly controversial Class I SO_2 increment consumption figure for the 24-hour averaging time. Petitioners contend that TGC is incorrect in claiming that the published increment consumption for Muhlenberg County based on the 0.167 lbs/MMbtu emission rate is the "area of TGS's highest impact". They point out that the public notice did not report TGS's consumption of the SO_2 Class I increment, which will be 4.98 $\mu g/m^3$ out of an allowable 5 $\mu g/m^3$ for the 24 hour SO_2 Class I increment in the Park, which TGC's modeling indicated is at 99.6% of the allowable level. Moreover, Petitioners point out that while the public notice, using the 0.167 lbs/MMbtu rate, reports a 24-hour SO_2 Class II increment consumption in Muhlenberg County of 20.95 $\mu g/m^3$, the updated SOB, released after the public comment period, reported a 24-hour SO_2 Class II increment consumption in Muhlenberg County of 53.8 $\mu g/m^3$. Jt. #7 at 32, Table 6.3. Petitioners note that this is more than two and a half times as much increment consumed as the Cabinet reported in the public notice. Hence, the public notice does not report the "worst case" impact.

Conclusions on increment information

199. Any discussion about deficiencies in the public notice begins with what is required by the regulations. If the regulation is not strictly complied with, it must then be decided whether these deficiencies render the public notice insufficient as a matter of law.

200. The regulations require that the public notice shall include “the degree of increment consumption expected to occur”. The regulations do not specify whether “increment” refers to only Class II increment (where the source is located), or to both Class II and Class I if the source will also impact a Class I area. In addition, the regulations do not specify whether the increment consumption is for counties beyond the county where the source is located. When the regulations by their language do not require that Class I increment or counties beyond Muhlenburg County be included, I cannot add these requirements to the regulations. A reasonable interpretation of “increment” as used in the regulation is increment in the county where the facility is located.

201. As already discussed, the final short term SO_2 permitted rate of 0.41 lbs/MMbtu was added after the public notice, and thus was not available at the time the public notice was published. I agree with the Cabinet that any discrepancies in the public notice and the SOB were inconsequential and would not have hindered public participation.

202. The parties cite numerous cases to support their positions on what is required in the public notice. A recent Kentucky Supreme Court case, Knox County v Hammons, Ky., 129 S.W.3d 839, 842-43 (2004), is instructive. Citizens challenged an occupational tax ordinance on the basis that the fiscal court failed to satisfy statutory requirements in publishing the proposed ordinance. Prior to passage, ordinances are required to be published, and the publication may be by summary. KRS 67.077(2). Summary is defined in KRS 67.075(2) as a “concise written

narrative covering the main points of any official statement, certified as to its accuracy by the fiscal court …”. Contrary to the requirements of the regulation, Knox County failed to certify the summary as to its accuracy. The citizens argued that KRS 67.077(2) requires strict compliance, and the failure to publish a summary which was certified by the fiscal court rendered the ordinance invalid. In determining whether strict compliance or substantial compliance was sufficient, the court considered whether this provision of the statute was mandatory or directory. Citing to Skaggs v Fyffe, 266 Ky. 337, 98 S.W. 2d 884, 886 (1936), the court depended “not on form, but on the legislative intent, which is to be ascertained by interpretation from consideration of the entire act, its nature and object, and the consequence of construction one way or the other.” Thus, “if the directions given by the statute to accomplish a given end are violated, but the given end is in fact accomplished, without affecting the real merits of the case, then the statute is to be regarded as directory merely.” In the Knox County case, the court concluded that KRS 67.077(2) was a directory provision because the intent was “to ensure that no county ordinance is passed in secret or without reasonable notice to the public.” 129 S.W. 3d at 843. The court held that the fiscal court’s certification of the summary was not absolutely necessary to accomplish the purpose of KRS 67.077(2) if the summary accurately and sufficiently describes the ordinance. Once the court determined that the provision was directory, substantial compliance would satisfy its provisions. The court then looked at the summary which was published and determined that the summary sufficiently covered the main points of the ordinance and clearly informed the public of its nature. Although the summary did not include the method of collection and enforcement of the tax, the court did not find that these provisions were “main points” of the ordinance. Hence, the court held that the publication substantially complied with KRS 67.077(2).

203. Comparing the public notice here to the situation in Knox County, I conclude that the public notice of June 19, 2002, sufficiently covered "the degree of increment consumption expected to occur". It must be remembered that the purpose of the public notice is to inform the public on the public issue involved and to allow meaningful participation. Conrad v. Lexington-Fayette Urban County Gov't., Ky., 659 S.W. 2d 190, 195 (1983); Merritt v City of Campbellsville, Ky. App., 678 S.W. 2d 788 (1988); Lyon v. County of Warren, Ky., 325 S.W.2d 302 (1959).

B. Informing the public of the Federal Land Manager's finding of a potential adverse impact

204. Petitioners also argue that the failure of the public notice to inform the public of the FLM's finding on August 22, 2002, Jt.#19, that at the 0.41 lbs/MMbtu 24-hr SO_2 limit there is a potential adverse impact on visibility is a violation of 401 KAR 51:017 § 15(3).

> 401 KAR 51:017 Section 15, Sources impacting Class I areas
> Subsection (3), Visibility analysis, provides:
>
> **The cabinet shall consider an analysis performed by the federal land manager**, provided within thirty (30) days of the notice and analysis required by subsection (1) of this section, **that shows that a proposed new major stationary source** or major modification **may have an adverse impact on visibility in a Class I area. If the cabinet finds that analysis does not demonstrate** to the satisfaction of the cabinet **that an adverse impact on visibility will result in the Class I area, the cabinet shall**, **in the public**

> **notice required in 401 KAR 52:100, either explain that decision or give notice as to where the explanation can be explained.** (Emphasis added).

Petitioners

205. Petitioners state that DAQ never provided the public with notice of the NPS finding of "potential adverse impacts" on visibility at the Park at the 0.41 lbs/MMbtu level because the letter of August 22, 2002, Jt. #19, was written almost two months after the public notice (of June 19, 2002) was issued. Petitioners urge that this lack of notice error was compounded by the public not having access to the 0.41 lbs/MMbtu modeling, which NPS relied upon in reaching its "potential adverse impacts" decision. Petitioners point out that NPS technical staff expressed concern "that the public really wasn't aware of a lot of the debate going on." P167 at 116:17-18 (Shaver depo.).

Cabinet

206. The Cabinet urges that when I granted TGC's motion for directed recommendation on Count 6 (Visibility/Mammoth Cave) in my April 12, 2004 Interim Report, Docket #257, I rejected this portion of Petitioners' claim on Count 2. The Cabinet argues that DAQ complied with 401 KAR 51:017 Section 15 when it reported in the June 19, 2002 public notice, Jt. #24, that it disagreed with the FLM'S original visibility determination (of February 14, 2002) based on the revised modeling DAQ received after the modeling that led to the FLM's original visibility objection.

TGC

207. TGC urges that NPS's August 22, 2002, letter simply describes the internal analysis that led to its ultimate determination to withdraw the adverse impact determination. TGC maintains that the public notice contained the required response to NPS's earlier visibility

analysis of February 14, 2002. Moreover, even if the August 22, 2002, letter amounted to an adverse visibility impact, it was not submitted within the 30-day period required by Section 15(3) and DAQ was thus under no obligation to explain any disagreement to the public.

Petitioners' Reply

208. In reply, Petitioners recap the facts with regard to the FLM's letter of August 22, 2002, which are as follows. The June 19, 2002, public notice informed the public of the FLM's February 14, 2002, finding (Jt. #19 and P167, Shaver depo., #28-NPS 003424) that TGC's emissions would have an adverse impact on visibility at the Park. This February 14, 2002, finding was based on modeling done at the 0.167 lbs/MMbtu emission rate. Shaver depo., #28-NPS 003424. However, this modeling had an error in its input files. Id. at NPS 003424. The FLM was aware of the error in the modeling at the time it issued its February 14, 2002, finding of adverse impact and had new information but did not have time to complete its review of the new information before the public comment period ended. Id. Thus, DOI submitted its adverse finding because the agency believed "it is important for KDAQ and the public to be aware of our concerns regarding this facility in the event the new analyses do not withstand technical scrutiny." Id. DOI did not have time to review the new information, Petitioners urge, because the Cabinet had not given DOI the amount of time to review the modeling matter that the regulations required. In an attachment to its February 14, 2002, letter, DOI states:

> … the KDAQ should have provided us with all information relevant to the permit application within 30 days of receipt and at least 60 days prior to public hearing. Furthermore, the KDAQ should have provided the FLM the opportunity to submit a visibility analysis within 30 days of the KDAQ's preliminary determination and before announcing the public hearing. The KDAQ transmitted its preliminary determination and draft permit to the NPS on December 28, 2001. On January 9, 2002, the KDAQ published a public notice announcing a February 12, 2002, hearing on the TGS application. The FLM did not have adequate time to consider the draft permit package or to make an adverse impact determination before the

> public notice was published. To exacerbate matters, we received additional material on February 6, 2002. As a result, the public has not been notified of the NPS's concerns or the reasons why the KDAQ agrees or disagrees. This compromises the public's ability to comment on this important issue, as envisioned by procedural requirements in the federal and state regulations. Id at NPS003431.

Petitioners agree with this attachment that the Cabinet's failure to advise the public of the FLM's finding of potential adverse impacts based on the 0.41 lbs/MMbtu emission rate "compromised the public's ability to comment on this important issue, as envisioned by the procedural requirements in the federal and state regulations." Id. Although TGC argues that 401 KAR 51:017 Section 15(3) does not apply to the DOI's August 22, 2002 finding of potential adverse impacts because DOI did not give the Cabinet its finding within 30 days of the notice and analysis required by subsection (1), Petitioners point out that the Cabinet did not provide DOI with the modeling at the 0.41 lbs/MMbtu rate until at least July 25, 2002. Jt. #22. DOI responded within 30 days of that date. Jt. #19. Petitioners urge that the Cabinet cannot be excused from giving the public notice of the FLM's finding simply because the Cabinet failed to provide the FLM with the necessary information in a timely manner. Such an interpretation, Petitioners contend, would create the perverse incentive for the Cabinet to delay in providing the FLM with information.

Conclusions on informing the public of the Federal Land Manager's finding of a potential adverse impact

209. I agree with the Cabinet's assertion that I rejected this portion of Petitioners' claim on Count 2 when I granted TGC's motion for directed recommendation on Count 6 in my Interim Order, Docket #273. In the Interim Order, I stated:

> In compliance with Section 15(3), the Cabinet advised the public in the public notice of June 19, 2002, Jt. Exh. 24, that it disagreed with the FLM's initial determination that emissions from TGS would have an adverse impact on the Park. While the FLM's August 22, 2002, letter notifies the Cabinet of concerns regarding the 24-hour SO_2 limit, it is not the finding referred to in Section 15(3), which must be provided by the FLM within 30 days of the notice from the Cabinet required by Section 15(1), and in fact had already been provided.

The purpose of Section 15(3) is to give notice to the public if the Cabinet does not agree with an FLM's analysis that a new major stationary source may have an adverse impact on visibility in a Class I area. The June 19 public notice did just this. When the initial finding of adverse impact was withdrawn and the FLM commented on the new short term SO_2 limit and its potential for adverse impact, the Cabinet was not required by Section 15(3) to issue another public notice. The public was notified in the June 19 notice that the FLM had found that emissions from TGS would have an adverse impact on visibility at the Park and that DAQ did not concur.

Area 3 – Statement of Basis

A. Explaining the legal and factual basis for permit conditions

210. Kentucky and federal regulations require that the Cabinet not issue a final Title V operating permit until the U.S. EPA has had an opportunity to review and comment on the permit and has not objected to issuance of the permit within the 45-day period for an objection. 401 KAR 52:100, Section 10(1).

Subsection (2), provides that

> The **cabinet shall provide a statement that sets forth the legal and factual basis for the draft permit conditions**, including references to applicable statutory or regulatory provisions, and shall send the statement to the U.S. EPA and to any other person who requests it. (emphasis added).

211. Before discussing each of the claims Petitioners make, there are two recent EPA Administrator orders, which although not controlling, speak to the issue of judging the adequacy of an SOB.

212. In the recent order of EPA Administrator Michael Leavitt, In the Matter of Los Medanos Energy Center, (EPA May 24, 2004) (69 Fed. Reg. 48862 (Aug. 11, 2004), environmental groups requested that he object to the issuance of the Title V Los Medanos permit. One of the claims of Petitioners was that the permit lacked a SOB. In reviewing this claim, Administrator Leavitt provided the following guidance on the content of an adequate SOB:

> A statement of basis ought to contain a brief description of the origin or basis for each permit condition or exemption. However, it is more than just a short form of the permit. It should highlight elements that EPA and the public would find important to review. Rather than restating the permit, it should list anything that deviates from a straight recitation of requirements. The statement of basis should highlight items such as the permit shield, streamlined conditions, or any monitoring that is required …Thus, it should include a discussion of the decision-making that went into the development of the title V permit and provide the permitting authority, the public, and EPA a record of the applicability and technical issues surrounding the issuance of the permit. Id. at p. 11. See also fn 16.

Administrator Leavitt continues by stating that if the permitting authority fails to provide EPA with an SOB, this does not necessarily demonstrate that the Title V permit is substantively flawed. If the record as a whole supports the terms and conditions of the permit, flaws in the SOB generally will not result in an objection by EPA. However, where flaws in the SOB resulted in, or may have resulted in, deficiencies in the Title V permit, EPA will object to the issuance of the permit. Id. He then reviewed the permit and all supporting documentation to determine whether they provided the factual and legal basis for certain terms and conditions of the permit and found that the "failure to adequately explain its permitting decisions either in the statement of basis or elsewhere in the permit record is such a serious flaw that the adequacy of the permit itself is in question". Id. Thus, he required the permitting authority to reopen the permit and make available to the public an adequate SOB that provides the public and EPA an opportunity to comment on the Title V permit and its terms and conditions as to the issues he identified. Id. at 13.

213. Shortly after the Los Medanos case, Administrator Leavitt was again presented with a case in which the SOB was challenged. In the Matter of Cargill, Inc., Petition IV-2003-7 (EPA July 16, 2004), a challenge to a Title V permit amendment, Petitioners claimed the SOB was inadequate. The Administrator restated the purpose of an SOB and stated when flaws in the SOB would lead to an objection. The Administrator found that the narrative and permit record provided little explanation for the numerical RACT chosen, which may have resulted in a permit flaw. For this reason, EPA granted Petitioners' claim based on the inadequacy of the SOB and permit record on the numerical RACT limit for boiler B001. Id. at p. 7 and 8. In his review of the Cargill case, Administrator Leavitt cites New York Public Interest Research Group, Inc. v Whitman, 321 F.3d 316, 333 n.11 (2d Cir. 2003), and notes that he is required by the CAA to issue a permit objection if a petitioner demonstrates that a permit is not in compliance with the requirements of the Act.

214. Of course, here, the issue is not that DAQ failed to issue a SOB, but whether the SOB was adequate. As stated in the Los Medanos and Cargill cases, if the SOB contains flaws, the record as a whole is then reviewed to see if it supports the terms and conditions of the permit.

215. TGC cites Alaska Dept. of Envtl. Conserv. v. EPA, 124 S.Ct. 983 (2004), a recent U.S. Supreme Court case in which the Alaska Department of Environmental Conservation (ADEC) and operator of zinc mining facility petitioned for review of three enforcement orders entered by EPA pursuant to the CAA, which effectively invalidated a PSD permit issued by ADEC to the operator. TGC cites this case for the court's statement that "(e)ven when an agency explains its decision with 'less than ideal clarity', a reviewing court will not upset the decision on that account 'if the agency's path may reasonably be discerned.'" Id. at 1006. The Court in the Alaska case held that the CAA authorizes EPA to stop construction of a major pollutant emitting facility permitted by a state authority when EPA finds that an authority's BACT determination is unreasonable in light of 42 U.S.C. Section 7479(3)'s prescribed guides, and the Court concluded that EPA properly exercised its statutory authority in this case. In reviewing EPA's action, the Court quoted the familiar default standard of the Administrative Procedure Act, which asks whether the Agency's action is arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law. Under this standard, the Court found that EPA did not act arbitrarily or capriciously in finding that ADEC's BACT decision lacked evidentiary support. Therefore, the Court held that EPA's orders were neither arbitrary nor capricious. Id. at 1009. (See also footnote 60 on p. 260 for a factual history of this case.)

B. The SOB contains no explanation for the elimination of IGCC and CFB from the BACT analysis.

Petitioners

216. Petitioners argue that the SOBs, Jt. #3, 5 and 7, are inadequate because they do not highlight elements that EPA and the public would find important to review and do not provide the permitting authority, the public, and EPA a record of the applicability and technical issues surrounding the issuance of the permit.

217. Specifically, Petitioners cite to the following alleged inadequacies of the SOBs:

*The SOB contains no explanation for the elimination of IGCC (Integrated Gasification Combined Cycle) and CFB (Circulating Fluidized Bed) from the BACT analysis

*The SOB is devoid of any documentation about the technical feasibility of achieving a NO_x limit of less than 0.08 lbs/MMbtu over a 30-day average

*The SOB does not reveal the percentage removal from TGS's SCR or explain why the percentage removal could not be higher

*The SOB does not mention the modeling done for the Cumulative Assessment

*The SOB does not explain the legal and factual basis for TGC's failure to conduct preconstruction monitoring for ozone

*The SOB discussion of the case-by-case MACT standard does not provide any factual explanation for how the mercury limit is more stringent that the best controlled similar source and how the mercury limit represents the maximum degree of emission reductions

*The SOB does not explain why emissions rates were not established based on the use of a baghouse or fabric filter

*The SOB fails to discuss the SO_2 short-term increment (both Class I and Class II) and NAAQS consumption determinations based on the 24-hour SO_2 emission limit of 0.41 lbs/MMbtu

*The SOB does not discuss the evaluation of whether TGC's hazardous emissions will harm humans or animals

Cabinet

218. The Cabinet states that it did not require TGC to do an analysis of IGCC or CFB in its BACT analysis because under existing statutes and regulations it could not require TGC to redesign the proposed facility, which using these technologies would require. Furthermore, Petitioners point to no statutory or regulatory requirement that the Cabinet was required to discuss IGCC or CFB in the SOB.

TGC

219. TGC responds by stating that the operative SOB is Jt. #7 which was issued with the permit on October 11, 2002. EPA was then given 45 days to review the permit, and TGC states that the final permit was issued on December 6, 2002. TGC maintains that DAQ explained its position on both of these issues in its response to public comments, Jt. #63 at 14, which was issued with the SOB, Jt. #7. TGC goes on to state that IGCC would redefine the source and therefore was not required to be considered in the BACT analysis. CFBs were also eliminated because TGC's proposed control technology was as good or better than CFBs and CFBs were not technically feasible for facilities the size of TGS.

Petitioners' Reply

220. In reply, Petitioners first urge that the relevant SOB is Jt. #5, not Jt. #7, as TGC contends. Jt. #5 was issued with the draft permit while Jt. #7 was issued with the final permit. Petitioners point out that contrary to TGC's claim, all parties have been operating under the belief that Jt. #6, issued on October 11, 2002, was the final permit, with Jt. #8, issued on December 6, 2002, being only a slightly revised version of the permit. Jt. #7, Petitioners urge, is the "final determination" required by the PSD regulations rather than the Title V regulations, to be issued with the final permit. See 40 CFR 51.166(q)(2)(vii) & (viii), incorporated into the Kentucky regulations at 401 KAR 51:017, Section 16, Public Participation. Petitioners point out that "obviously" the SOB, which contains an explanation of the legal and factual basis for the draft permit conditions, is to be issued with the draft permit to help the public and EPA understand the draft permit. If, as the Cabinet and TGC maintain, that the legal basis for not considering IGCC and CFB in the BACT analysis is that the definition of BACT does not allow such a consideration, then the SOB was required to state this. Moreover, the Cabinet's response to comments, Jt. #63 at 14 (which were issued on October 11, 2002, and respond to why other

technologies were not selected) cannot cure the failure to provide a legally sufficient SOB that the public should have been able to use to prepare their comments.

Conclusion on explaining the legal and factual basis for permit conditions

221. I agree with Petitioners that the SOB which is at issue is Jt. #5, which was issued on June 19, 2002, in conjunction with issuance of the draft permit, Jt. #4, and at the time the public comment period began. Jt. #7 was the final and third version of the SOB and went out to EPA with the permit which was issued on October 11, 2002. A minor permit revision was issued by DAQ on December 6, 2002. Jt. #8.

222. I am constrained by the requirements of 401 KAR 52:100, Section 10(2) which requires only that the SOB set forth the basis, legally and factually, for the draft permit conditions. The use of IGCC and CFB are not permit conditions, and thus, no explanation is required in the SOB for why these technologies were rejected. Moreover, under the Administrative Orders cited by Petitioners, the SOB (or elsewhere in the permit record) must adequately explain the permit decision. Alternative designs and fuels were discussed in the permit record, e.g. Jt. #44 at Red 18.

C. The SOB is devoid of any documentation about the technical feasibility of achieving a NO_x limit of less than 0.08 lbs/MMbtu over a 30-day average

Cabinet

223. The Cabinet's response, Jt. #7 at 20, is that the SOB clearly states that the choice of NO_x BACT was an SCR/low NO_x burner configuration chosen to be below EPA proposed regulations on ozone and to meet the most stringent NO_x limit in the RACT/BACT/LAER[33]

[33] RACT/BACT/LAER means Reasonably Available Control Technology, Best Available Control Technology, and Lowest Achievable Emissions Rate.

Clearinghouse, a database maintained by EPA, which contains a listing of limits imposed on permitted units.

TGC

224. TGC says that the NO_x emission limit is explained in the permitting record by multiple submittals from TGC. Jt. #33 at Red 53-54; Jt. #17 at Red 107-108.

Conclusion on the failure of the SOB to include documentation about the technical feasibility of achieving a NO_x limit of less than 0.08 lbs/MMbtu over a 30-day average

225. Again, Petitioners are requesting that the SOB explain why TGC was not required to achieve a certain emission limit. As stated, 401 KAR 52:100, Section 10(2) does not require an explanation of terms and conditions which are not in the permit.

D. The SOB does not reveal the percentage removal for TGS's SCR or explain why the percentage removal could not be higher.

Petitioners

226. Petitioners state that the SOB states that SCRs operate at between 60 and 90% efficiency when the permit provides for 55.6% control efficiency. Also, the SOB does not include the boiler outlet NO_x concentration, which is the SCR inlet concentration.

Cabinet

227. The Cabinet states that Petitioners point to no requirement to include the exact NO_x removal percentage or the boiler outlet NO_x concentration in the SOB.

TGC

228. TGC says SCR specific information is not necessary to determine the NO_x emission rate, which was provided in the POC (pollutants of concern) table attached to TGC's application.

Conclusion on the failure of the SOB to reveal the percentage removal for TGS's SCR or explain why the percentage removal could not be higher.

229. I agree with Petitioners that when the SOB, Jt. #5 at 11, in Table 5.2 – Ranking of Control Technologies by Effectiveness, showed 60-90% for SCRs, there should have been an explanation for the permit's 55.6% control efficiency.

E. The SOB does not mention the modeling done for the Cumulative Assessment, even though the Cabinet's position is that the Cumulative Assessment included modeling for compliance with the ozone NAAQS, as required by 401 KAR 51:017 Section 10(1)

Petitioners

230. Petitioners point out that the SOB simply states that the Cabinet does not believe that TGS will cause an ozone problem "due to the construction of Thoroughbred Generating Station based on the level of estimated emissions of nitrogen oxides and volative organic compounds from the proposed facility and the amount of these pollutants currently being emitted….". Jt. #5 at 27; Jt. #7 at 35.

Cabinet

231. The Cabinet responds that there is no requirement for citing the Cumulative Assessment, which is a public document which was published on December 12, 2001, in support of its conclusions on TGS's ozone impacts.

TGC

232. TGC states that this issue was not raised before or during the formal hearing. TGC also states that the issue of TGS's compliance with the relevant ozone NAAQS was previously argued in Count 3. In dismissing Count 3, I recognized that ozone modeling was conducted by EPA on a regional basis, not by an individual facility. Interim Report, Docket

#273 at 7. EPA performed the ozone modeling for the area that included TGS, and the Cabinet included these results in the Cumulative Assessment. The modeling demonstrated that TGS will not contribute to a NAAQS violation.

Petitioners' Reply

233. In reply, Petitioners urge that a review of the permit record would lead the public to conclude that no ozone modeling was ever done. Instead, if the determination of compliance with the ozone NAAQS was based on the Cumulative Assessment, this should have been stated in the SOB. Petitioners cite NRDC v. Hodel, 865 F.2d 288 (D.C. Cir. 1988), a case in which the D.C. Circuit Court of Appeals reviewed a five-year schedule of offshore oil and gas leasing activity proposed by the Secretary of the Interior. The Court at 298 stated that conclusory remarks do not equip a decision maker to make an informed decision.

Conclusion on the failure of the SOB to mention the modeling done for the Cumulative Assessment

234. Petitioners do not refute TGC's claim that this issue was not raised before or during the formal hearing. For this reason, I decline to review this claim.

F. The SOB does not explain the legal and factual basis for TGC's failure to conduct pre-construction monitoring for ozone

Cabinet

235. The Cabinet points out that I already ruled in my Interim Report, Docket #273, p. 7, that Petitioners' claims regarding preconstruction ozone monitoring are without merit.

TGC

236. TGC argues that this issue was not raised before or during the formal hearing, and in addition, TGC urges that this issue was dismissed in Count 3.

Conclusion on the failure of the SOB to explain the legal and factual basis for TGC's failure to conduct pre-construction monitoring for ozone

237. Petitioners do not refute that TGC's assertion that this issue was not raised before or during the formal hearing. Thus, it will not be considered.

G. The SOB discussion of the case-by-case MACT standard does not provide any factual explanation for how the mercury limit in the permit is more stringent than the best controlled similar source and how the mercury limit represents the maximum degree of emission reductions

Petitioners

238. While the SOB contains a reference to "Additional information reviewed" upon which DAQ bases its conclusion that the 80% removal is equal to the best controlled similar source, such a reference does not identify the material relied upon. Jt. #5 at 4.

Cabinet

239. The Cabinet states that the fact that DAQ simply referenced the case-by-case MACT discussion in the permit instead of reproducing it, verbatim, in the SOB, does not make the SOB flawed and is not a reason for revoking or remanding the permit.

TGC

240. TGC says this claim was not raised by Petitioners before or during the formal hearing. Regardless, the SOB contains an entire section devoted to the MACT determination.

Conclusion on the failure of the SOB discussion of the case-by-case MACT standard to provide any factual explanation for how the mercury limit in the permit is more stringent than the best controlled similar source and how the mercury limit represents the maximum degree of emission reductions

241. Petitioners do not refute the assertion that this claim was not raised prior to or during the formal hearing. Thus, it will not be considered.

H. The SOB does not explain why emissions rates were not established based on the use of a baghouse or fabric filter.

Cabinet and TGC

242. The Cabinet and TGC state that the use of a baghouse or fabric filter for mercury was adequately addressed by the Cabinet in its Final Response to Comments, Jt. #63 at 15, which was sent out with the final proposed permit on October 11, 2002, and also at Jt. #17 at 104-105; 146-148, TGC's responses dated September 16, 2002.

Petitioners' reply

243. In reply, Petitioners urge that even in Jt. #7 at 23 the SOB has no explanation of the legal or factual basis for the Cabinet's conclusion that a dry ESP is equivalent to baghouse for control of non-criteria pollutants.

Conclusion on the failure of the SOB to explain why emissions rates were not established based on the use of a baghouse or fabric filter.

244. I agree with Petitioners that the SOB should explain DAQ's reason for concluding that a dry ESP is equivalent to a baghouse or what the "clear technical concerns", Jt. #63 at 15, are that justify the use of ESP controls.

I. The SOB fails to discuss the SO_2 short-term increment (both Class I and Class II) and NAAQS consumption determinations based on the 24-hour SO_2 emission limit of 0.41 lbs/MMbtu

245. The omission of this information in Jt. #5, the SOB Petitioners rely on, is because DAQ did not even have the 0.41 lbs/MMbtu modeling when this SOB was issued on June 19, 2002.

Cabinet

246. The Cabinet states that the final SOB, Jt. #7, contains the 0.41 lbs/MMbtu 24-hour SO_2 limit at pg. 21, 31 and 34. Furthermore, the emissions limit in the final permit is more stringent than the one previously public noticed.

TGC

247. TGC's response is that Jt. #7 discusses the final SO_2 short term limit of 0.41 lbs/MMbtu at 31. ("A block maximum average emission rate over 24 hour period to protect the NAAQS and the Class II PSD increments has been set at 0.41 lbs/MMbtu based on additional modeling."). This SOB clearly states that the tables providing the short-term NAAQS and increment numbers are "based on a 0.41 lbs/MMbtu" emissions limit. Id. at 32-33.

Conclusion on the failure of the SOB to discuss the SO_2 short-term increment (both Class I and Class II) and NAAQS consumption determinations based on the 24-hour SO_2 emission limit of 0.41 lbs/MMbtu

248. As I concluded earlier in this Count, Petitioners were advised of the less stringent 0.45 short term SO_2 emission rate, Jt. #5 at 13, in the public notice of June 19, 2002. The fact that a more stringent rate was later decided upon would not have denied the public from commenting on this issue.

J. The SOB does not discuss the evaluation of whether TGC's hazardous emissions will harm humans or animals

Cabinet

249. The Cabinet responds by stating that Petitioners have put on no evidence to show that it is required to do a risk assessment on the TGC facility. This is a case-by-case determination under 401 KAR 63:020, Kentucky's air toxics regulation.

TGC

250. TGC states that this claim was not raised before or during the formal hearing. Relying on the Cumulative Assessment, DAQ reasonably determined that TGS would not have a harmful effect on humans and animals.

Petitioners' Reply

251. In reply, Petitioners again state that if the Cabinet's obligations under 401 KAR 63:020 were met by the Cumulative Assessment, the SOB was required to so state.

Conclusion on the failure of the SOB to discuss the evaluation of whether TGC's hazardous emissions will harm humans or animals

252. Although Petitioners do not refute that this issue was not raised earlier, my conclusion on Count 1 addresses this claim by finding that 63:020 requires that the Cabinet evaluate the impact of TGS's potentially hazardous or toxic substances on animals. The SOB should discuss this evaluation.

Area 4 - Response to public comments

253. For permits which require public review, the Cabinet is required to prepare a response to the comments received during the comment period.

254. 401 KAR 52:100, Section 2, Public Comment Period, provides:

(1) For permit actions that require public review, **the cabinet shall**:
…

(b) **Prepare a response to the comments received during the comment period.** (Emphasis added).

Petitioners

255. Petitioners maintain that DAQ did not adequately respond to IDEM's comments, all of which were based on federal requirements applicable to Kentucky, not Indiana specific requirements. Also, in responding to public comments about protecting human health, Petitioners urge that DAQ initially stated that it had no authority to regulate human health. Now DAQ's response is that it does have authority, but the Cumulative Assessment fulfilled its obligation.

Cabinet

256. The Cabinet points out that Petitioners fail to identify which of the thousands of public comments DAQ received to which it failed to respond. Also, it urges that Tom Adams addressed each and every comment to which IDEM witness Nisha Sizemore testified.

TGC

257. TGC responds by stating that DAQ responded to each of IDEM's comments; IDEM simply did not like the response. Also, DAQ actually met with IDEM to review their concerns and the meeting was attended by technical staff and management personnel from both departments.

Petitioners' reply

258. In reply, Petitioners urge that DAQ is required to actually provide a written response to all comments, not rely on changes in the permit as its response. Petitioners also point out that DAQ's response to some comments reflects a different position than DAQ took later.

Conclusion on response to public comments

259. There are several cases which speak to the standard of review when an agency's responses to comments are challenged. In Natural Resources Defense Council v. U.S. Environmental Protection Agency, 859 F.2d 156, 188 (D.C. Cir. 1988), the court reasoned that "(t)he APA requirement of agency responsiveness to comments is subject to the common-sense rule that a response be necessary. Failure to respond is not grounds for APA invalidation unless the points raised in the comments were sufficiently central that agency silence would demonstrate the rulemaking to be arbitrary and capricious. (citations omitted) The fundamental purpose of the response requirement is, of course, to show that the agency has indeed considered all significant points articulated by the public; in addition, agency responsiveness aids in the Congressionally sanctioned process of judicial review of agency action. (citation omitted)." In Mt. Diablo Hospital v. Shalala, 3 F.3d 1226, 1233 (9th Cir.1993), the court held that "(t)here is no obligation to make references in the agency explanation to all the specific issues raised in comments. The agency's explanation must simply enable a reviewing court to see what major issues of policy were ventilated by the informal proceedings and why the agency reacted to them the way it did," citing to South Carolina ex rel. Tindal v Block, 717 F.2d 874, 886 (4th Cir. 1983), *cert denied*, 465 U.S. 1080, 104 S.Ct. 1444, 79 L.Ed.2d 764 (1984).

260. In Newport Steel Corp. v. Natural Res. and Envtl. Prot. Cabinet, File No. DAQ-24117-043 (Feb. 18, 2000) at 25-26, 2000 WL 1232396, a case heard by this Office, Newport urged that DAQ's response to comments did not adequately articulate its rationale or reasons for requiring CEMS and did not respond to specific comments Newport made. The Secretary concluded that DAQ reasonably articulated its reasons for requiring CEMS and rejecting other periodic monitoring approaches. "The purpose of these provisions is to alert affected persons to

the reason for the decision, and the information given does fulfill that goal. While detail was not provided, in its response to comments DAQ did state the same reasoning for the decision that it has stated throughout this proceeding." [34]

261. In stating that DAQ did not adequately respond to IDEM's comments, Petitioners cited to P158 at 39:1, which is the deposition of Janet McCabe, assistant commissioner of IDEM's Office of Air Quality. In response to the question whether IDEM believes that DAQ's response to comments (and SOB) inadequately explained the rationale for DAQ's determinations, Ms. McCabe responded:

> To the extent that suggestions that we made were not accepted by Kentucky, at least in some of those instances we felt like they either didn't accept them because they just disagreed with them and they had a rationale for them or for some other reason. And in the technical support document in response to comments, in at least some of those instances, and I'd have to go back and review them all to see if it's all of them, where we continued to have concerns, we felt that their explanation was not adequate. So had they given more explanation – there's a difference between did they explain it enough, did they not explain it enough or do we just disagree with their explanation. And I think there was some of both.

Basically, McCabe seems to be saying that DAQ's explanation to IDEM's comments about technical support documents was not adequate in some instances. This generalization by Ms. McCabe and Petitioners' failure to point to specific comments and specific responses prevent me from determining whether DAQ's responses were inadequate.

262. Next, Petitioners urge that in response to public comments about protecting human health, DAQ initially stated that it had no authority to protect human health. Jt. #63 at 18. Now, however, DAQ states that it does have authority, and the Cumulative Assessment

[34] Petitioners state that this "unpublished administrative determination is not binding precedent". Contrary to Petitioners' assertion, a final order of the Secretary of this Cabinet is binding on a Hearing Officer in this Cabinet unless it can be distinguished factually from the subject case or unless there are legal reasons why the Hearing Officer would urge the Secretary to reconsider the ruling in the prior case.

fulfilled its obligation. The comment to which Petitioners refer, from the Sheet Metal Workers International Association, is:

> "(w)hat are the accumulated projected health effects on the general populace downwind from the proposed site? What are the potential acute health effects? What are the long-term chronic health effects? Who is responsible and liable for health effects caused by this plant?"

DAQ's response was as follows:

> The Natural Resources and Environmental Protection Cabinet has general authority under Kentucky Revised Statutes Chapter 224 to maintain an air quality program. The division is not authorized to establish health standards. TGS, as designed and permitted, will meet all applicable state and federal standards for protection of the environment.

263. I agree that a reference to the Cumulative Assessment, in which the Cabinet conducted a human health risk assessment, and which in this litigation the Cabinet urges constitutes compliance with 401 KAR 63:020, was the appropriate response.

264. In summary on Count 2, with a few exceptions, the Cabinet complied with the public participation requirements during the permitting process.

<u>COUNT 8 - Additional Impacts Analysis, Soils, Vegetation</u>

Count 8 - Findings

Overview

265. Section 14 of 401 KAR 51:017 requires TGC to provide an analysis of any impacts on soils, vegetation and visibility that might result from emissions from its facility, as well as emissions from growth associated with its facility.

266. Petitioners maintain that the Cabinet did not require the type of Additional Impacts Analysis required by Section 14 of TGC's pollution impacts on soils, vegetation and visibility in Class II areas. Moreover, Petitioners urge that TGC did not offer any data in support of its summary conclusions, did not include any impacts from associated growth in its modeling analysis, and did not obtain a list of local types of soils and vegetation and determine their sensitivity to pollutants emitted from the facility. Furthermore, TGC did not do an analysis of its impacts plus background, as EPA's guidance suggests, before comparing that concentration to the screening levels provided in the guidance document.

267. The Cabinet points out that although EPA was initially not satisfied with the Additional Impacts Analysis submitted by TGC, EPA was apparently satisfied with the supplemental analysis submitted by TGC. The Cabinet points out that the area surrounding the facility is post-mining reclamation and partial agriculture, not pristine forest, and for this reason, DAQ was comfortable with the level of detail devoted to Section 14.

268. TGC acknowledges that it did not add background concentrations to its impacts before comparing them to the EPA guidance document screening values. However, TGC urges that these issues were raised and resolved during the permitting process when DAQ responded to a comment by EPA by stating that Section 14 only requires TGS to determine its impact, along with secondary growth, on soils and vegetation. In summary, TGC states that when EPA and DAQ requested a more detailed analysis than the original Additional Impact Analysis submitted, TGC sought guidance on how to perform the analysis, and both DAQ and EPA accepted the additional submittal. TGC maintains that DAQ's acceptance of the analysis was reasonable and had a sound basis in fact.

General Findings

269. The pertinent portions of 401 KAR 51:017 Section 14, Additional Impact Analysis, provide as follows:

> (1) The **owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation** that would occur **as a result of the source** or modification **and general commercial, residential, industrial and other growth associated with the source** or modification. The owner or operator is not required to provide an analysis of the impact on vegetation having no significant commercial or recreational value.
> (2) The **owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth** associated with the source or modification. (emphasis added).

270. TGC provided its initial Additional Impact Analysis in the February, 2001, Permit Application. Jt. #61, Section 7.5, at Red 100-02. The analysis includes four brief sections:

7.5.1 Construction and Growth Impacts
7.5.2 Impact on Soil
7.5.3 Impact on Vegetation
7.5.4 Impact on Visibility

271. The testimony adduced regarding these four sections is as follows:

In the Construction and Growth Impacts section, TGC estimated that it would employ some 1,000 people from the local community where possible during construction, and permanent employees would be about 500. Industrial growth associated with TGC is expected to be fairly minimal because the kinds of industries which supply ongoing materials are already in place as a result of other power plants in the area. 4/22/02 TE at 26, 28. (Tickner). According to Tickner, to evaluate the labor forces which were available, TGC talked to "various local administrative folks, labor unions, universities, community colleges, economic development folks…" 4/22/04 TE at 28 (Tickner). No documentation was made of these conversations. Peabody was also familiar with the mining work force unemployment based on its history of mining operations in the area. Id.

272. In the other three sections, Soil, Vegetation, and Visibility Impacts, TGC used a qualitative approach. This approach considered that the area in the vicinity of TGS is reclaimed surface mined land and partial agriculture, not "a pristine area". In other words, it was not expected that there would be a sensitive species there. 5/4/04 TE (Handy). The significance of the TGC project being in a postmining area is that the vegetation is "rather robust …and is not a sensitive ecosystem development". 4/15/04 TE at 33. (Adams). TGC acknowledges that "(a)ny facility emitting significant amounts of particulates, SO_2, and NO_x has a theoretical potential impact on visibility through atmospheric discoloration and reduction of visual range…" However, because of the rigorous evaluation of visibility impairment in the nearby Class I area, TGC assumed that the visibility in the Class II areas would be similar. 5/4/04 TE at 28 (Handy). TGC determined that there were no visually sensitive areas designated in the area except for the Class I area of the Park. Jt. #57 at Red 100; 1/12/04 TE at 82 (Handy); see also 5/4/04 TE (Handy). TGC concluded that if it could get approval in the Class I area for visibility, then it assumed the rest of the Class II areas would also be similar. Also, TGC would be held to opacity requirements coming out of the stack in the near-field, which people will see in the Class II area near the facility. 5/4/04 TE at 28-29 (Handy).

273. The Cabinet's position is that there are "no resources, no state parks, no culturally significant areas and such that have been identified in this area where a small to moderate decrease in visibility would be of concern." 4/15/02 TE at 35 (Adams). Sensitive Class II areas are supposed to be cultural resources, unspoiled areas and such. 4/15/04 TE at 34 (Adams). Also, "modern power plants aren't having these highly localized effects that one of the old power plants would have." Id. at 36.

274. In its initial analysis, TGC considered only impacts from SO_2 and NO_x. Subsequently, EPA and DAQ asked TGC "to do some other type of screening to insure that some of these pollutants, some of the metals that are in here, nickel, selenium and stuff, to do some type of additional analysis, screening analysis to show they would not cause harm, either." 5/4/04 TE at 18 (Handy). TGC consulted with DAQ and EPA Region 4 to ask for guidance on determining what screening values to use because the Kentucky regulations are silent as to approved screening values. 5/4/04 TE 59-60, 63, 89 (Handy). EPA recommended and provided the screening values found in "A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals", Report EPA 450/2-81-078, Dec. 12 1980 (the "EPA Screening Guidance"). P104-39.

275. The EPA Screening Guidance, P104-39 at 27, provides for steps to be followed in using the guidance document. Specifically, this guidance document provides that the air pollution impacts from TGS are to be added to background levels to get a total ambient concentration before comparing that concentration to the screening levels provided in the guidance document. P104-39 has a diagram, Fig. 5.1 on p. 26, labeled Pollutant Pathways, showing that ambient air concentration is made up of the source and background concentrations.

276. In its October 26, 2001, revised permit application, TGC provided a supplemental Additional Impact Analysis in Section 7.5 to address EPA's concerns for additional analyses. Jt. #57 at Red 96-100. Revisions were made in two sections, the Impact on Soil and Impact on Vegetation sections. No changes were made in the other two sections, Construction and Growth Impacts or the Impact on Visibility sections.

277. TGC acknowledges that it did not follow the step in the EPA guidance document which requires that impacts from TGS are to be added to background levels. Handy stated that

neither EPA nor DAQ directed it to follow all the steps in the EPA Screening Guidance. 5/4/04 TE at 60-62 (Handy). TGC contends that the guidance was to be consulted only for the screening values it contained. Id. at 86-87. Handy said he told EPA and DAQ how TGC intended to use the EPA Screening Guidance. Id. at 20, 60.

278. Table 7.5.2-1 of TGC's supplemental Impact on Soil section provides the metals analysis. Jt. #57 at Red 98. The table "uses the modeling results for the various pollutants" to calculate the deposited concentrations for various metals that were then compared "to a screening value for either soils or plant tissue." 5/4/04 TE at 22 (Handy).

279. Table 7.5.3-1 of TGC's supplemental Impact on Vegetation section addresses impacts on vegetation from SO_2 and NO_x. Jt. #57 at Red 100. This table "looks at SO_2 and NO_x and compares those to the sensitive vegetation numbers that were provided in the … screening analysis document." 5/4/04 TE at 24. (Handy). The sensitive vegetation numbers are the most conservative and should be used as indicated in footnote "d" to Table 3.1 in P104-39, p. 11, "unless it is known that only intermediate or resistant plants will be affected." Section 3.2.2, P104-39, p. 10, states that the values in Table 3.1 "represent the minimum concentrations at which adverse growth effects or tissue injury in exposed vegetation were reported in the literature."

280. In TGC's comparison of the modeled impacts to the sensitive vegetation screening values, the modeled impacts were "well below the screening values". 5/4/04 TE at 27.

281. In response to TGC's supplemental analysis, EPA included the following Comment 8 regarding Vegetation Impacts. Jt. #44, February 28, 2002 Comments, at Red 34:

> The vegetation sensitivity levels used for impact comparison are ambient concentrations. These values were inappropriately compared with modeled incremental Thoroughbred concentration. The cumulative ambient concentrations

from all emission sources should be used for comparison with table 7.5.3-1 vegetation sensitivity levels.

282. TGC responded on March 10, 2002, at Jt. #44 at Red 34 as follows:

As previously indicated in our December 12, 2001 and February 28, 2002 responses, it is not appropriate to use cumulative concentrations for comparison to the sensitivity levels, since the goal is to predict the impacts associated with the facility being proposed. KYDAQ's PSD Regulation 401 KAR 51:017 Section 14(1) states that the applicant shall provide the analysis of the impacts on soil and vegetation as a result of the source, or modification. Additionally, it has been demonstrated that the impacts from the facility will be below the secondary national ambient air quality standards, which were established to ensure there will be no harmful effects on soils and vegetations.

283. On July 18, 2002, EPA Region 4 sent a letter to DAQ responding to its revised SOB and the revised draft permit, dated June 19, 2002, Jt. #4 and 5. The following comment is made with regard to the Additional Impact Analysis:

g. Additional Impact Analysis – PD/SB (preliminary determination/statement of basis) Section 7 results for the Additional Impact Analysis do not reflect the 0.45 lb/MMbtu SO_2 short-term emission rate. Because the target sensitivity levels used for vegetation impact assessment are associated with total concentrations, proper comparison can only be made with cumulative modeled concentrations that include all emission sources. The application incorrectly used only incremental Thoroughbred concentrations. TGC218, p. 3.

284. TGC's response to this letter is found in Jt. #17, Responses and Comments, dated September 16, 2002, at Red 12:

As indicated in the August 9, 2002 letter from Dianna Tickner to Don Newell (Attachment 3), TGC emissions are insignificant in comparison to the current acid deposition rate (i.e. less than 1% of the current deposition rate). Therefore, TGC does not need to perform cumulative modeling for vegetation impacts. Analyses performed with respect to the EPA requested 24-hr SO_2 limit have demonstrated to the satisfaction of NPS and KYDAQ that all NAAQS Class I and Class II increment issues have been addressed.

285. DAQ's final response to public comments, Jt. #63 at 12, states: "…401 KAR 51:017 only requires TGS to determine their impact, along with secondary growth, on soils and vegetation. TGS has performed that required analysis." Adams testified that TGC's analysis was more thorough than in most states. 6/14/04 TE (Adams).

286. In the final SOB, Jt. #7 at 35, DAQ concluded:

> The project lies in an area of mainly post mining use. No significant off-site impacts are expected from the proposed action. Therefore, the potential for adverse impacts to either soils or vegetation is minimal. It is concluded that no adverse impacts will occur to sensitive vegetation, crops or soil systems as a result of operation of the proposed project. …
>
> Additionally, the Commonwealth of Kentucky has not determined any Class II areas in the vicinity of the proposed plant to have visual sensitive criteria established. Therefore, no significant change in visibility is expected from the facility.

287. Though the project lies in an area of mainly post mining use, Petitioners point out that all of the area between the Park and TGS is not reclaimed surface mine. The significant impact area (SIA), as determined for the SO_2 NAAQS modeling, is a circle of some 50 kms. in all directions from the facility. Within the SIA is an area designated by Peabody as a wildlife management area, which has not been undermined, on the opposite side of the road from the plant, which is leased to the Kentucky Fish and Wildlife Service. 12-5-03 TE at 8:17-10:2; P176- location map. No study was done of the vegetation or soils within that area. In addition, there are numerous homes within 10 miles of TGS, in the vicinity of Central City, and areas which are being farmed. P167 (location map showing homes).

288. In rebuttal, Dr. Fox contacted a Kentucky botanist, Dr. Julian Campbell, who confirmed that numerous species of both woody plants and grasses and agricultural crops which are sensitive to SO_2 occur within 30 miles of Central City. Listed as woody plants within 30

miles of Central City are the following: “Eastern white pine, Large-toothed aspen, Green ash, Yellow birch, Lowbush blueberry, Lombardy poplar, Black willow, Oaks, Paper birch, Poplar, Willow, Norway spruce, Virginia pine and Shortleaf pine”. Listed as grasses and agricultural crops within 30 miles of Central City are the following: “Alfalfa, Blue-grass cultivars, Ryegrass, Buckwheat, Red clover, Radish, Pea, Rhubarb, Timothy, Swiss chard, Turnip, Cucumber, Tomato, Potato, Raspberry, Spinach, Cabbaga, Corn, Soybean, Green onion, Carrot, Chili pepper and Peanut.” PR333; 6/2/04 TE at 37-51.. Petitioners equate many of the sensitive species identified in PR333 as being “commercially or recreationally significant”. Section 14 provides that an analysis of the impact on vegetation is not required on vegetation if it has “no significant commercial or recreational value”.

289. Also in rebuttal, Petitioners point out that TGC did not evaluate what ozone damage would occur to vegetation below the eight-hour ozone NAAQS. The EPA guidance document points out that the screening concentration for ozone for an eight-hour average is 0.06 ppm, while the eight-hour ozone NAAQS is 0.08 ppm. P104-39 at 11. A 2001 letter from the NPS states that “(v)egetation and soils can be impacted by air pollution concentrations at or below the NAAQS”. TGC22 at TB000867. Petitioners urge that it is arbitrary for TGC to take a screening value for SO_2 out of the EPA Screening Guidance, but not take a screening value for ozone out of the same document. The Cumulative Assessment, Jt. #11 at 33, notes that some areas may fail to meet the 8-hour ozone standard. These are areas where there are additional emissions associated with power plants. Petitioners suggest that Respondents should have compared the data from the ozone modeling in the Cumulative Assessment to the ozone screening value of 0.06 over an eight hour average in the EPA Screening Guidance.

Count 8 – Parties’ Arguments

Petitioners

290. Petitioners argue that TGC's supplemental soils and vegetation analysis is flawed because the Cabinet did not require TGC to add background concentrations to the modeling results before comparing them to the EPA guidance screening values. They urge that the screening values from the EPA Screening Guidance, P104-39, are a standard to be compared against a source's impact *plus* background[35]. P104-39 at 27. See also 5/4/04 TE 57:20-59:10 (Handy). Failure to consider the pollution which is already in the air results in a predicted concentration that has no relationship to reality.

291. EPA's Region 4 confirmed that the screening values are to be compared against a source's impact plus background. P23 at 15 (Comment 8). See also TGC218 at 3. In contrast, TGC compared its impacts alone, without background concentrations, to the values from the EPA Screening Guidance. Although Handy, TGC's consultant, chose to use the EPA Screening Guidance, he did not use TGC's impact plus background because "(t)hat's all we're required to do. You have to look at the source's impacts on the soils and vegetation as part of the additional impact assessment." Id.

292. Petitioners seek to demonstrate that they proved that TGS's pollution will have an impact to vegetation above the acceptable level in the EPA guidance document, P104-39, which

[35] Petitioners clarify that a cumulative analysis means an analysis of the impacts to TGS and other major sources (as was done for the NAAQS and increment modeling), while background can include pollution transported a long distance but does not necessarily include other major nearby sources because there is no way to know if those other sources were contributing or even operating when the ambient air monitoring data was gathered. In my Interim Report, Docket #273, I state that "I agree with TGC and the Cabinet that there is no reference in Section 14 requiring that the analyses of the impact of emissions be cumulative, i.e., a consideration of the impact over 30 years, for example." My recollection is that when I questioned Cabinet counsel regarding the meaning of cumulative in the context of Section 14, the response was that it meant over a number of years. Thus, this reference in the Interim Report does not speak to the issue at hand as to whether the analysis required by Section 14 is to include TGS's impacts plus background.

TGC and the Cabinet chose to use. 6-2-04 TE at 28:16-29:11 (Fox). In PD190-40[36], a demonstrative exhibit prepared during the testimony of Handy (TGC's expert), it is shown that TGC's computer modeling, P223, predicted that TGS will create SO_2 concentrations of up to 276.2 µg/m^3. The actual ambient air before TGS begins emitting pollution showed a high concentration of 594.19 µg/m^3 and second high concentration[37] of 575.87 µg/m^3. PD190-40, citing PD104-39. (The figures used in PD190-40 are local records from the TVA Paradise facility because PD104-39 at 32 suggests that local records be used.) Thus, Petitioners point out that even using the less conservative concentration value of 575.87 µg/m^3 would result in an impact of 852.07 µg/m^3 when TGS begins emitting pollution. PD190-40. This exceeds the screening value for 3-hr SO_2 of 786 µg/m^3 from Table 3.1 of the EPA guidance document.

293. In response to claims by TGC and the Cabinet that the EPA Screening Guidance does not require the use of the maximum background concentration, Petitioners refer to P104-39, p 32, which states that it is not addressing background concentrations for gaseous criteria pollutants (such as SO_2). "For these gases, it was felt that local records would be likely to provide more timely and complete information". Id. Petitioners point out that the figures used in PD190-40 are local records from the TVA Paradise facility. Petitioners also point out that PD104-39 at 32 discusses background estimates for annual averaging time, whereas PD190-40 addresses SO_2 impacts based on a three-hour averaging time. Dr. Fox testified that when doing a screening risk assessment for short term averaging times, the high value is used because

[36] PD190-40 is entitled Comparison of 1993 3 hr highest calculated background value and TGS's 1986 High-First-High 3 hr predicted impacts to screening value found in P104-39 Table 3.1

[37] High concentration and second high concentration are a modeler's way of saying the highest and second highest number at a particular receptor. 11-17-03 TE at 62 (Scire).

screening risk assessments are supposed to involve conservative assumptions. 6/02/04 TE 22:18-23:12.

294. Although TGC claims that EPA accepted the TGC analysis, the only support for this claim are statements by Ecton that EPA did not object to issuance of the permit. Petitioners urge that the fact that EPA did not formally appeal the permit proves nothing. See e.g. In the Matter of an Air Pollution Control Construction Permit Issued to Wisconsin Electric Power Company for the Elm Road Generating Station, Permit No. 03-RV-166, located in Oak Creek, Wisconsin, Case No.: IH-04-03 (Wisc. Div. of Hearing and Appeals Aug. 3, 2004) at 11, in which the Administrative Law Judge notes the very limited extent to which EPA historically challenges a state permitting decision.

295. Petitioners also point out that the predicted impact values TGC relies on for the one-hour and three-hour SO_2 impacts in Jt. #57 at 100 are incorrect because they are based on an emission rate based on the 0.167 lbs/MMbtu 30-day permit limit rather than the higher 0.41 lbs/MMbtu 24-hour permit limit in the current permit. As stated before in this report, this is known because at the time the permit application, Jt. #57, was submitted, the 0.41 lbs/MMbtu emission rate did not exist.

296. With regard to TGC's argument that compliance with the NAAQS shows there will be no impacts to soils and vegetation, Petitioners point out that Congress has made clear that the PSD program is to protect public health and welfare (including effects on soils, crops, vegetation, animals, wildlife and visibility) "notwithstanding attainment and maintenance of all national ambient air quality standards." 42 U.S.C. Section 7470(1); Section 7602(h). In addition, the NPS stated that "(v)egetation and soils can be impacted by air pollution concentrations at or below the NAAQS." TGC22 at TB000867.

297. Petitioners add that they believe it is arbitrary for TGC to take a screening value for SO_2 out of the EPA Screening Guidance and not take a screening value for ozone out of the same document. Even accepting that ozone modeling is not done on an individual basis, Petitioners point out that the Cumulative Assessment shows that ozone modeling can identify a problem caused by one particular proposed power plant. Petitioners suggest that Respondents should have compared the data from the ozone modeling in the Cumulative Assessment to the ozone screening value of 0.06 over an eight-hour average in the EPA Screening Guidance.

298. Turning now to the analysis required by Section 14 of impairment and associated growth, Petitioners suggest that Ms. Tickner's testimony as to communications she had on this issue is not credible because it came after denial of TGC's motion for directed recommendation on this issue and because Handy, not Tickner, was the consultant preparing the permit. In addition, Petitioners point out that there is no documentation of any such conversations, as recommended by the NSR Manual. Jt. #9 at D.1.

299. Finally, Petitioners point out that TGC failed to perform an analysis of impairment to visibility outside the Class I area. Petitioners argue that TGC's reliance on the fact that Kentucky has not determined any Class II areas in the vicinity of the proposed plant to have visual sensitive criteria is misplaced. Jt. #7 at 35. TGC's reliance is based on a theory that its pollution will stop at its boundary and thus affect only post-mining areas. This is inconsistent, Petitioners urge, with the fact that the significant impact area (SIA) for the Class II modeling for SO_2 was 50 km and the fact that there were also impacts on visibility at the Park, which is over 70 km away. Jt. #5 at 24, Table 6.2. TGC did not conduct an analysis of the visibility impacts closer to TGS such as in Central City or in the nearby wildlife management

area, even though at a distance of over 70 km, TGC's pollution can decrease visibility by over 16%. See P100-4 at 3, Table 4, year 1996.

Respondents

300. Respondents state that Petitioners' sole support for their arguments is language from guidance documents. While pointing out that neither the NSR Manual nor EPA technical guidance are binding on the Cabinet, Respondents urge that TGC's analysis comports with the NSR Manual's suggested approach for an Additional Impacts Analysis, i.e., it considered the "visual quality of the area" (post-mining use with no visually-sensitive areas) and the analysis qualitatively evaluated the possibility of near-field visibility impairment (it conducted an aggressive Class I visibility analysis; there are capacity limits on a well-controlled modern facility). Jt. #9, Chapter D, II D (p D.6). Thus, TGC concludes that the decision that additional computer modeling was not warranted was reasonable.

301. With regard to the screening value for SO_2, Respondents claim that there is no regulatory requirement that the lowest conceivable screening value ever reported in the literature must be used. In fact, there is no regulatory screening value for SO_2 beyond the secondary NAAQS. They urge that ozone modeling, other than that conducted in the Cumulative Assessment, is irrelevant with respect to an additional impacts analysis.

302. TGC and the Cabinet emphasize that the area in the vicinity of TGS is reclaimed surface mine land, and thus, impacts to soils and vegetation are not a concern. However, Handy acknowledged that within the area where TGS's pollution will have impacts, there are non-mined lands including Central City and a wildlife management area. 5/4/04 TE at 34:17-36:20 and 93:14-94:18. In rebuttal, Petitioners introduced evidence that sensitive vegetation is located

near the TGS proposed site. See e.g. PR333; 6/02/04 TE 51:13-23. Respondents objected to this testimony coming in by rebuttal.

303. Respondents claim that TGC's Class II *qualitative* visibility analysis was more than adequate, i.e. since there was no adverse impact to visibility at the Park, this is a good indicator that problems are not perceived in the other areas. DAQ agreed that TGS would not cause an adverse impact on visibility. DAQ did not expect a large visibility impact anywhere from TGS. 4/15/04 TE at 35-36 (Adams). Adams testified that he "discussed with Region 4 what they had expected to see down on this visibility impairment and it's just not a commonly invoked provision of the regulations, partially because experience shows that modern power plants aren't having these highly localized effects that one of the old power plants would have." Id. at 36. In addition, the emissions from TGS are not predicted to cause a violation of secondary NAAQS, which are standards set to protect ecosystem concerns. Id. at 37.

304. In a rebuttal exhibit, the Cabinet introduced the Plum Point Energy permit in Arkansas dated October 31, 2003, to show that in the Soils and Vegetation Analysis, the Arkansas Department of Environmental Quality found that because all pollutants are below the secondary NAAQS levels, Plum Point's emissions are not expected to result in harmful effects to the soils and vegetation in the area. CabR227-1 at p. 7.[38]

Count 8 – Conclusions

Analysis of impacts on soils and vegetation

305. Following TGC's initial analysis, when EPA and DAQ requested that TGC do a screening analysis for soils and vegetation, TGC asked for guidance on determining what

[38] However, I note that CabR 227 at p. 6, shows that Plum Point's emissions are added to background before the comparison to NAAQS.

screening values to use. EPA recommended the screening values in its guidance screening procedure. P104-39. As stated, this guidance document clearly states that air pollution impacts from TGS are to be added to background levels to get a total ambient concentration *before* comparing that concentration to the screening levels provided in the guidance document. In spite of this requirement, TGC and DAQ continue to maintain that Section 14 requires only an analysis of impairment from TGS and other growth, without adding background to the source. They do not explain how the screening values from the EPA guidance document, which are based on the concentration from the source plus background, can be compared to the impact from only TGS. They simply rationalize that because this is not a pristine area, the level of detail in the analysis was good enough. Handy's testimony to the effect that EPA somehow acquiesced to TGC using the guidance document only for the screening values it contains, and not for the steps in the guidance document, is not credible. Indeed, EPA persisted in submitting comments that advised TGC to add background concentrations to its impact before a comparison with screening values. Jt. #44 at Red 34; TGC218 at 3. It is elemental that a PSD applicant cannot demonstrate that its impact will not exceed EPA screening levels by taking screening levels from the EPA guidance document and using them in a manner not recommended by the guidance document. When an EPA guidance document is used, as here, it must be used in accord with the steps prescribed for its use. In addition, it is my conclusion that 401 KAR 51:017, Section 14, requires that TGS's impacts must be added to background before an analysis of the impairment to visibility or an analysis of the air quality impact. To do otherwise ignores the reality that TGS is not the only source impacting the visibility and air quality in the Class II area.

306. Although Adams testified that no sensitive vegetation was identified in the area, 4-14-04 TE at 85; 4-15-04 TE at 33-34, his testimony is challenged by rebuttal evidence adduced by Petitioners showing that many sensitive species are found within 30 miles of Central City. Despite objections to this evidence, it is appropriate evidence to rebut Adams' testimony. Both TGC and DAQ failed to consider that the pollution from TGS will not be limited to the area which Respondents describe as post-mining reclamation. As stated, there is a wildlife area designated by Peabody within the SIA, numerous homes within 10 miles of TGS, and crops grown in the area. In spite of these facts, TGC did not actually investigate whether there were sensitive species within the SIA.

Analysis of construction and growth impacts

307. Although the Construction and Growth Impacts section does not evidence the conversations Ms. Ticker testified occurred, in light of Peabody's previous mining activity in the area, and its familiarity with the area, including the mining work force unemployment, I do not find the Construction and Growth Impacts section to be inadequate.

Analysis of impacts on visibility

308. With regard to the impact on visibility, TGC acknowledges that it did not conduct an analysis of impairment to visibility outside the Class I area. Instead, it relied on the Class I visibility analysis and the fact that there are no "visual sensitive criteria" established in any of the Class II areas in the vicinity of the plant. Section 14, however, specifically requires an analysis of the impairment to visibility in the Class II area, with no exceptions if there are no visual sensitive criteria in the area. I conclude that it is reasonable to conclude that the analysis include the SIA, especially considering the proximity of Central City and the wildlife area to TGS.

309. Based on the above, I conclude that DAQ erred by approving TGC's Additional Impacts Analysis which was not performed in accord with 401 KAR 51:017, Section 14. The specific flaws in the Additional Impacts Analysis are the following: comparison of TGS's impacts alone to screening values in EPA's Screening Guidance, P104-39, instead of comparing impact values from the facility *plus* cumulative ambient concentrations to the screening values; failure to conduct an analysis of impairment to visibility within the Class II SIA of TGS; and failure to consider whether there is vegetation within the SIA which has significant commercial or recreational value.

310. I recommend that on remand, TGC be required to perform and submit an Additional Impacts Analysis in accord with these conclusions.

COUNT 9 – Best Available Control Technology (BACT)

Count 9 - Findings

Overview

311. Since TGS is a new major stationary source, it is required to apply the best available control technology (BACT) for each pollutant subject to regulation under the CAA that it will have the potential to emit in significant amounts. 401 KAR 51:017 Section 9(2). A BACT analysis is performed for each pollutant subject to PSD review. Thus, the emissions of PM/PM_{10}, SO_2, NO_x, CO, VOC, beryllium, H_2SO_4 (sulfuric acid mist) and mercury are subject to BACT review. Jt. #33 at Red 14. BACT is an ongoing consideration during the permitting process until the date the permit is issued, in this case, October 11, 2002.

312. Petitioners contend that DAQ's BACT determinations are not supported by a reasoned analysis, and the TGC permit has emission limits which are not BACT. Specifically, Petitioners allege that the BACT analyses involve numerous errors, including:

* Failure to follow the top-down analysis
* Failure to consider CFB and IGCC
* Rejection of coal washing
* Failure to consider using higher quality coal
* Permit limits for NO_x, SO_2, PM[39] and mercury are not BACT
* No BACT determination for the coal and fly ash handling systems
* No BACT determination for the auxiliary boiler

313. The Cabinet maintains that the law and the relevant evidence support DAQ's decision which was based on what is "achievable for that source", in accord with the definition of BACT. The Cabinet urges that "achievable for that source" means what was achievable for the plant as designed by TGC, i.e. two 750 MW pulverized coal-fired boilers burning western Kentucky coal.

314. TGC also urges that BACT does not require a "redefinition" of the proposed source or the use of unproven technology. It maintains that DAQ's determinations reflect this and the case-by-case nature of BACT determinations, and the record supports DAQ's reasoned justification for its BACT determinations.

Experts' Opinions

315. Petitioners presented: Dr. Phyllis Fox, who was recognized as an expert in the review of air permit applications as they relate to BACT; Bill Powers, who was recognized as an expert in environmental engineering and air pollution control technology; Nisha Sizemore, IDEM engineer, who drafted the comments on the TGC permit; and Don Shepherd,

[39] Petitioners are now in agreement that the PM limit of 0.018 lb/MMbtu is BACT as a result of Revision #2 which clarified that the limit is for combined filterable and condensable PM.

environmental engineer, Air Resources Division, NPS, who has some 26 years experience in making and reviewing BACT determinations.

316. The Cabinet presented Tom Adams, senior environmental engineer, DAQ's Permit Review Branch.

317. TGC presented Bryan Handy, a consultant with KEC who was recognized as an expert on BACT analyses and requirements; Tom Lillestolen, an engineer and director of Global Technology for ALSTOM, who was recognized as an expert in air pollution control equipment, design and evaluation; and Ms. Tickner, project manager for TGS.

318. Dr. Fox and Shepherd are clearly the most experienced witnesses in their personal experience of preparing and reviewing BACT analyses. A summary of the five major witnesses on this Count follows.

Dr. Phyllis Fox

319. In preparing her opinions related to the BACT analysis prepared by TGC, Dr. Fox reviewed all of the discovery production by Respondents, some 50,000 pages of material. She attended and/or reviewed the deposition transcripts of all witnesses who gave testimony on BACT. She also did extensive research on her own to pull together additional information. While she has not personally prepared a BACT analyses for a coal-fired power plant, as emphasized by TGC, she has reviewed quite a few and has prepared and/or reviewed hundreds of BACT analyses on a variety of pollution control systems. Dr. Fox notes that she is not proposing any specific emission limits for TGC, and she has not gone through a formal top-down BACT analysis for TGS. However, she is proposing lower emission limits for TGS.

320. Dr. Fox's opinion regarding the sufficiency of the final BACT determination is that the Cabinet relied on information provided by TGC, which was inadequate. Thus, the

determination made by the Cabinet was inadequate. Although the Cabinet attempted to do some additional research of its own, the Cabinet does not have the resources to do the kind of review that is required for such a large, complex project. It is the applicant who has the obligation to do the research and develop the database or develop the information on which a BACT determination should be based.

321. Upon being asked whether there is a single pollution control train that TGC could have selected that would produce lower emissions limits that were achievable over the long term, Dr. Fox recommends an SCR system that is designed for a larger NO_x reduction efficiency because the current permit limit, based on 55.6%, is a very low NO_x removal efficiency for SCR. This could be followed by a fabric filter baghouse, which would allow TGS to achieve a higher PM limit and would also reduce some of the SO_2 and capture a greater fraction of the mercury. She would couple the fabric filter baghouse with sorbent injection, much like the TULEP and B&W "How Low Can You Go?" paper, to be followed by either a wet FGD and ESP or a circulating dry scrubber. With the circulating dry scrubber, the wet ESP would not be needed because a circulating dry scrubber removes essentially 100% of the SO_3, and the main purpose of the wet FGD is to take out the SO_3. 12-2-03 TE at 169 (Fox). The technologies that were not included in the BACT analyses, but should have been, include: circulating dry scrubber, fabric filter, powdered activated carbon with a baghouse, and an SCR that would achieve 90% NO_x removal.

Don Shepherd

322. Shepherd's testimony was provided via his videotaped deposition and transcript. P160, and P160A and B[40]. Shepherd became involved with the TGC permit application early in 2001. This was the first pulverized coal-fired boiler that he had seen in the NPS' Air Resources Division office. Shepherd testified that the general approach of NPS, Air Resources Division, is to "work out the issues", which he said meant that the NPS would rather come to a mutually acceptable resolution on a permit than deny the permit.

323. His review involved looking at what emission rates and control technologies are being proposed by the applicant and comparing that to his office's knowledge of the state of the art of control technology, as well as what other similar applicants are proposing or being permitted to do. He saw that pollution control technology was evolving and improving over the time that his office was reviewing the TGC application.

324. At the time of permit issuance, his Air Resources Division thought that the control technology that TGC selected was appropriate, but it could be used more effectively. Since issuance, Shepherd has modified his views to believe that the 30-day rolling average limit for SO_2 is appropriate, and even very good, for the kind of coal TGS is burning, but the short-term limit is too high. He thinks the short-term limit should be in the 0.2 lbs/MMbtu range. The NO_x limit could be lower, down to 0.07 lbs/MMbtu, based on a number of power plants which are achieving, or proposed, or permitted at rates lower than TGS.

325. The particulate limit could be lower, probably not higher than 0.10. He thinks that coal washing may have been the best opportunity to reduce SO_2, but it was not adequately

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[40] Exhibit 2 to Shepherd's deposition is a set of tables which he compiled during the time NPS was actively reviewing TGC's application, with the exception of a permit or two issued after TGC's permit. The set of tables ranks power plants by their emission rates for all pollutants. Exhibit 3 to his deposition was generated in January 2003, after the TGC permit was issued, and is organized for sulfur dioxide in a different way, i.e. by ranking power plants according to the increasing sulfur content in the coal. NO_x and PM are ranked solely by emission limits.

tested for feasibility and the economic analysis of coal washing was not adequate. He thought that more analysis should have been conducted on the feasibility of other types of mercury control, such as coal washing which would reduce the sulfur input to the boiler. Another consideration Shepherd mentioned was substitution of a coal with less sulfur. However, because this was a mine mouth plant, he felt such an analysis would be beyond the bounds of a BACT analysis.

326. In sum, he believes that the BACT analysis was not adequate to support the final determinations in the permit.

Tom Adams

327. At the time of the TGC permit, Adams had done two or three engineering reviews of BACT determinations. He described BACT determinations as rather protracted negotiations between the applicant and the agency. He said that although the NSR Manual is a perfectly acceptable way to determine a BACT, it does not touch on multi-pollutant concerns. He believes that all DAQ's BACT determinations are appropriate and the BACT emission limits in the TGC permit represent the best available technology as of October 11, 2002.

Bryan Handy

328. As KEC's project manager for the TGS project, Handy gathered information for the BACT submittals, contacted other regulatory agencies, performed research, and interviewed potential vendors. Handy estimated that he worked on about 10 PSD applications with BACT analyses while he was employed with DAQ and about 10 since his employment with KEC; not all were on coal-fired power plants. Handy is of the opinion that all the BACT determinations reached by DAQ are correct.

Tom Lillestolen

329. Tom Lillestolen is the director of Global Technology at ALSTOM, the technology control vendor which submitted a bid for TGS. He opined that the technology selected and approved for TGS is the best AQC (air quality control) equipment for the TGS plant, and there was no commercially available technology which would achieve lower emission limits as of October 11, 2002.

COUNT 9 – General Findings

Conducting a BACT analysis

330. Kentucky's BACT definition, found in 401 KAR 51:017 Section 1(8), provides in pertinent part:

> **"Best available control technology" means** an **emissions limitation** (including a visible emission standard) **based on the maximum degree of reduction for each pollutant** subject to regulation under 42 USC 7401 to 7671q (Clean Air Act), which would be emitted from a proposed major stationary source or major modification which the cabinet, on a **case-by-case** basis, taking into account **energy, environmental, and economic impacts and other costs,** determines is **achievable for that source** or modification through application of production processes or **available methods, systems, and techniques, including fuel cleaning** or treatment **or innovative fuel combustion techniques** for control of that pollutant. (Emphasis added).

331. Drawing from the definition, there are certain key elements to a BACT analysis:

a. It is a case-by-case analysis.

b. BACT limits must be achievable.

c. Control technology must be available.

d. Candidate BACT limits can be eliminated on the basis of energy, environmental, and economic impacts and other costs.

332. It is generally accepted that a BACT limit is to be determined through a top-down BACT analysis, although a top-down analysis is not required by the CAA. A top-down BACT analysis is the process that EPA developed for implementing the definition of BACT, which was set out in a series of EPA guidance memoranda that go back to the mid 1980s and was finally solidified in the draft October 1990 New Source Review Workshop Manual (NSR Manual) Jt. #9 at B.5. As agreed by the parties, the draft October, 1990, NSR Workshop Manual is not binding on DAQ because it has not been incorporated in the regulations. However, as also

agreed by the parties, it is relevant guidance information and as such, it is appropriate for use by the Cabinet.[41] DAQ does follow a top-down approach in making BACT determinations. 5-3-04 TE 192:23-25 (Andrews).

333. In each of the BACT analyses TGC submitted, it cites to the NSR Manual as being the guide for conducting a BACT analysis and indicates that it followed the draft BACT guidelines. Jt. #61 at Sec. 4; Jt. #57 at Sec. 4; Jt. #33 at Sec. 4. DAQ also notes that TGC submitted a top-down BACT analysis following the NSR Manual. Jt. #3 at 13; Jt. #5 at 10; Jt. #7 at 18.

334. Both Dr. Fox and Shepherd testified that the NSR Manual is "the bible" for doing BACT analyses. Dr. Fox stated that the NSR Manual is used in every state in which she has worked. "(T)he only process I have seen in 20 odd years of doing this in 20 odd states is the top-down BACT process as outlined in the NSR Manual". 6-1-04 TE at 78:1-3 (Fox). Bill Powers also stated that the NSR Manual has been the base template for top-down BACT analyses since the late 1980s.

335. The steps in a top-down BACT analysis, as set out in the NSR Manual, Jt. #9, Chapter B, are as follows:

Step 1 - <u>Identify all control technologies</u>
List is comprehensive (Lowest Achievable Emissions Rate - LAER included).

Step 2 - <u>Eliminate technically infeasible technologies</u>
Clearly document that technical difficulties would preclude the successful use of the control option.

Step 3 - <u>Rank the remaining control technologies by their control effectiveness</u>
Ranking should include:

[41] See Order entered on February 1, 2004, Docket # 249, Order Granting TGC's Motion for a Ruling that the Draft October 1990 NSR Workshop Manual is Not Binding on DAQ, But Denying Request to Exclude Evidence Pertaining to the Manual.

control effectiveness (percent pollutant removed)
expected emission rate (tons per year)
energy impacts (BTU, kWh)
environmental impacts; and
economic impacts

Step 4 - Evaluate the most effective controls and document results
Case-by-case consideration of energy, environmental and economic impacts. If the top technology is selected, it is unnecessary to evaluate the energy, environmental, or economic impacts of the various technologies.

Step 5 - Select BACT
BACT is the most effective option that was not rejected based on cost, energy or environmental reasons.

336. Adams described the sources of information to be considered in a top-down BACT analysis. 4-12-04 TE at 68-69. He finds permit limits are the most reliable information because "regulatory agencies actually have authority to insure and monitor that these limits are being achieved at all times." Id. at 69. The next most important source to Adams are permit applications, even though the emission limits in applications "almost always go down from when an application comes in to when the permit is issued, but … with some of these multi-pollutant concerns, sometimes they get adjusted up or down based on other considerations." Id. Following permit applications, he finds CEMS data the most important as a "good indication of approximately the level a source can meet. Id. at 70-71. Next in importance is vendor information, followed by short-term stack tests. Id. at 74, 77.

337. When asked the most common way to set BACT in the U.S., Dr. Fox agrees that looking at BACT determinations of other agencies is one of the most common. She finds it an acceptable way to set a BACT limit as long as it is not the only method used. "One should additionally consult other sources of information including applications, journal articles, vendor guarantee information, short-term performance tests, experience overseeing." 11-18-04 TE at 41-

44. With regard to TGC's reluctance to use vendor guarantees in its BACT analysis, Fox points out that all vendor guarantees that she relies on in her testimony have been backed up by short-term performance tests, and the NSR Manual specifically identifies short-term performance tests as one of the things that can be relied upon in performing a BACT analysis. She states that because vendors are on the hook financially for the guarantees that they make, they back up their guarantees by performance tests.

338. Don Shepherd opined that the following are appropriate considerations in making a BACT determination: vendor guarantees (although he does not put a lot of stock in vendor guarantees), plant proposals and demonstrations, CEMS results, and findings by other regulatory agencies.

339. The NSR Manual lists the following sources for inclusion in a BACT analysis:

1) EPA's BACT/LAER Clearinghouse (a database maintained by EPA containing a list of limits imposed on permit units);

2) BACT guidelines and determinations made by the South Coast Air Quality Management district or SCAQMD;

3) control technology vendors;

4) federal, state, local new sources review permits and associated inspection/ performance tests;

5) environmental consultants;

6) technical journals, reports and newsletters (e.g. the McIlvaine Newsletters[42] and the referee journals, like the Journal of the Air Pollution Control Association), air pollution control seminars; and

7) EPA's New Source Review bulletin board. Also mentioned are technologies in application outside the U.S. if they have been successfully demonstrated in practice on full scale operations. Jt. #9, the NSR Manual, at B.11.

TGC's BACT Analyses

340. TGC submitted the following BACT analyses and supplemental information. (Issuance of the draft permits and final permit are also listed):

* February 28, 2001 initial application, Jt. #61
* October 26, 2001 revised application, Jt. #57
* December 12, 2001 responses to comments from DAQ, EPA, and NPS, Jt. #56
* December 28, 2001 first draft permit, Jt. #2
* February 28, 2002 response to follow-up comments from EPA Region IV, NPS and others, TGC185
* March 10, 2002 response to EPA comments, Jt. #44
* April 24, 2002 coal washing submittal, Jt. #42
* May 10, 2002 responses to inquiries from DAQ, EPA Region IV and others, Jt. #41,
* May 29, 2002 addendums to the October 26, 2001 application, Jt. #33
* June 19, 2002 second draft permit, Jt. #4
* September 16, 2002 responses and comments on the second draft permit, Jt. #17, and
* October 11, 2002 final permit, Jt. #6

341. TGC's initial BACT analysis is found in its initial application submitted on February 28, 2001, Jt. #61 at Red 27-56. TGC identifies the NSR Manual as a guide to

[42] Dr. Fox described the McIlvaine report as a widely read journal that reports news in the power industry. The McIlvaine report is specifically referenced in the NSR Manual as one of the sources to be considered.

performing a BACT analysis. TGC's BACT analysis was based solely on one source, the RACT/BACT/LAER Clearinghouse. This application proposed the following limits:

SO_2	0.294 lb/MMbtu*[43]
NO_x	0.10 lb/MMbtu*
PM/PM_{10}	0.018 lb/MMbtu
VOC	0.072 lb/MMbtu
CO	0.10 lb/MMbtu*
H_2SO_4	0.306 lb/MMbtu*

Id. at Red 55.

342. The NPS, EPA and DAQ filed comments stating that these proposed limits would not be acceptable because of adverse impact to visibility and other air quality related values at the Park**.** TGC22.

343. In order to address these concerns, TGC took several steps. It had Black & Veatch prepare an evaluation of the effectiveness and risks posed by technologies (P137-61), TGC personnel investigated technologies and traveled to plant sites in the U.S. and Europe. 12-11-03 TE at 111-121(Tickner). TGC states that it "was interested in finding the lowest emissions levels achievable in practice."

344. Based on information compiled, TGC and Black & Veatch prepared a bid specification and requested bids on the air quality control system (AQCS) to meet limits that modeling showed would be needed to address the visibility issues. P177, July 27, 2001. The specification listed certain emission levels for which TGC was seeking a guarantee. 3-16-04 TE (Lillestolen). The requested specification was 0.10 lbs NO_x/MMbtu and a request for alternative bids at 98% and 99% removal efficiency for SO_2. 12-11-03 TE at 132-33; 122-23

[43] Based on a 30 day average

(Tickner). Most bidders offered to meet 0.08 lbs NO_x/MMbtu. No one submitted a bid on the alternate 99% removal of SO_2, and no one bid lower than 0.018 lbs/MMbtu for PM.

345. Only one bidder, ALSTOM, submitted complete commercial terms. 12-11-03 TE at 138 (Tickner). Lillestolen, director of Global Technology at ALSTOM, testified that he is not stating that the limits in the TGC permit are the lowest ALSTOM could guarantee. 3-16-04 TE. Lillestolen is not aware that TGC asked ALSTOM whether it could achieve a lower NO_x, SO_2 or PM limit or asked the "how low can we go" question. With regard to PM, he says ALSTOM is quite aggressive on particulates, so it would struggle very hard to make a more stringent guarantee. Id. at 110. He does not give an opinion as to whether the NO_x, PM or SO_2 emission limits are the best limits achievable by the control technology selected for the TGC plant. Id. at 106. When a customer desires an emission level lower than ALSTOM can readily guarantee, the Global Technology group gets involved in making a technical risk assessment and a determination as to whether ALSTOM could support a guarantee.

346. Lillestolen distinguished between "technically feasible technology", "demonstrated technology" and "commercially available technology". While acknowledging that there was "technically feasible technology" which would achieve lower emission levels for TGC as of October 11, 2002, he was not aware of "demonstrated technology" which could achieve lower emission levels and stated there was no "commercially available technology" which would achieve lower emission levels.

347. Lillestolen is in agreement with the ALSTOM letter in Jt. #44 at Red 99, stating that "(b)ased on this information and taking into consideration the contingencies described, the DRY ESP–WET FGD-WET ESP is the best AQC technology for this specific plant."

348. Based on ALSTOM's bid, TGC revised its permit application and on October 26, 2001, submitted its final complete application and a revision to its BACT analysis. Jt. #57 at Red 26-57. The revised application contained the following proposed BACT limits:

SO_2	0.167 lb/MMbtu
NO_x	0.09 lb/MMbtu
PM/PM_{10}	0.018 lb/MMbtu
VOC	0.0072 lb/MMbtu
CO	0.010 lb/MMbtu
H_2SO_4	0.00497 lb/MMbtu

Jt. #57 at Red 55.

349. Although TGC's consultants indicated a need for a cushion, and thus did not propose 0.08 for NO_x, TGC subsequently acquiesced to DAQ's and EPA's position that the NO_x limit should be 0.08 lbs/MMbtu. Jt. #30; 5-3-04 TE at 217 (Handy). Later, TGC agreed to a short-term SO_2 limit of 0.41 lbs/MMbtu with a commitment to reduce it further based on two years of operational data. TGC maintains that this short-term SO_2 limit is not meant to be a BACT limit. 1-6-04 TE at 86 (Handy).

350. In response to the first draft permit, EPA expressed its concern with the "paucity of information sources referenced" in TGC's BACT analysis and states that the only reference source TGC cites is the RBLC (RACT/BACT/LAER Clearinghouse) database, which "is a starting point, not an ending point". Jt. #44 at 12. EPA continues, "we note that Peabody is considered the world's largest coal company. We would expect from this position that Peabody would have access to a wealth of information about coal-burning power plants that goes well beyond the information in the RBLC". Id. EPA lists examples of references which should have been consulted, including NO_x control levels at the existing coal-fired power plants that have SCR, the SO_2 control levels at coal-fired power plants that have installed FGD, specific technical articles, control methods and emission rates proposed by Peabody for the Prairie State Energy

Campus in Illinois (which is essentially identical to TGS), and permits and permit applications at some ten pulverized coal boiler projects which EPA lists but which is not meant to be inclusive of all new projects in the U.S. and does not include projects in other countries or retrofits of existing PC boilers. In summary, EPA states "the applicant cites only five projects as comparable with the proposed Thoroughbred Generating Station. We believe that this falls far short of being an adequate comparison." Id. at Red 13.

351. On May 29, 2002, TGC submitted Addendums, Jt. #33, to its October 26, 2001, application. The Addendums contained TGC's refined top-down BACT summary at Red 4-79, and again, refer to the NSR Manual as the guide for performing a BACT analysis, at Red 16. Addendum 1 was intended to replace the earlier BACT demonstration in the October 2001 application and to identify additional projects. Addendum 1 contains Table 4.2-1 which is TGC's revised BACT Comparison of New, Proposed, and Permitted Coal Fired Power Plant Emissions Limits. Jt. #33 at Red 21. This table lists 27 power plants in the U.S. in addition to TGS, all of which were either proposed or permitted. The power plants were not limited to PC boilers or to western KY bituminous coal. Eleven of the power plants were Circulating Fluidized Bed (CFB) units; the rest were PC boilers and one plant was SCPC (supercritical pulverized coal). None were Integrated Gasification Combined Cycle (IGCC).

352. TGC evaluated each of the facilities in Table 4.2-1, noting the similarities and differences between TGS and each of the facilities. The facilities were evaluated according to the following categories: MW, unit type, permit or application, date filed, agency, primary fuel, emission limits lb/MMbtu, and equipment. In notes beside each facility, TGC compared each facility to TGS based on the following:

1. Boiler design is not similar

2. No emission limit/emission limit too high for current BACT
3. No BACT analysis/Net out on PSD
4. Primary fuel is not similar
5. Similar boiler design and fuel use
6. No permit yet/not demonstrated

353. TGC eliminated virtually all of the facilities identified, without getting to the step in a top-down BACT analysis where the applicant analyzes cost effectiveness or unacceptable energy or environmental impacts. The plants using CFB were eliminated because the boiler design was not similar and the primary fuel was not similar.

354. Ms. Tickner maintains that TGC's BACT analyses were used to derive the permit limits as opposed the BACT limits being based on the control technology selected (as Petitioners argue). However, a Black & Veatch document dated September 17, 2001, entitled Client Meeting to Discuss Permit Status, at p. 3, bullet 12, states "Develop BACT analysis based on control technology selected." P137-116.

355. In questioning, Ms. Tickner is asked whether TGC left out a lot of information available to the company about lower limits being achieved for SO_2, PM and NO_x, as well as the range of control effectiveness available by SCR and the technical feasibility of coal washing. Ms. Tickner stated that she would not characterize it that way because TGC presented a lot of information on removal rates to the Cabinet.

DAQ's BACT Determinations

356. In doing its BACT determination, DAQ contacted some other states to be aware of what they were doing with respect to BACT determinations. 4-15-04 TE at 8-9 (Adams). Adams also received EPA's "cheat sheet" of power plants and recent permits, although he notes that certain recent permits were not on the EPA sheet. Cab30. DAQ worked closely with Region 4 on BACT issues. 4-12-04 TE at 39 (Adams).

357. Although DAQ and TGC considered clean coal technologies, such as IGCC and CFB, these technologies were not subjected to a BACT analysis. IGCC was rejected because DAQ and TGC believe this would require "redefining" the source and had not been demonstrated at the size of TGS (750MW). Specifically, DAQ does not believe that IGCC is an "innovative fuel combustion technique", which the definition of BACT requires to be considered. CFB was also rejected because it had not been demonstrated at the size of TGS. Alternative fuels were considered, but rejected because DAQ determined it did not have authority to require TGS to change fuels. Jt. #63 at 14-15. The use of coal washing to reduce SO_2 was rejected on the basis of energy, environmental and economic impacts.

358. DAQ determined that BACT for the PC boilers at TGS to be:

SO_2	0.167 lbs/MMbtu
NO_x	0.08 lbs/MMbtu
PM	0.18 lbs/MMbtu
VOC	0.0072 lbs/MMbtu
CO	0.10 lbs/MMbtu
H_2SO_4	0.00497 lbs/MMbtu

Parties' Arguments on the meaning of "Available" and "Achievable for that Source"

359. As stated earlier, there are certain terms in the definition of BACT which are key elements to a BACT analysis. While the parties are in agreement as to the meaning of some of these elements, they strongly disagree on other elements. Since a resolution on these elements will influence whether the BACT analyses were flawed and resulting BACT determinations are arbitrary, they will be discussed at this point.

360. The two elements which are most contentious are the meaning of "available" and "achievable for that source".

Available

Petitioners

361. While not binding on Kentucky, Petitioners cite to several EPA Environmental Appeals Board decisions, in urging that "available" refers to a technology which sufficient data indicate has the realistic potential for application to the regulated pollutant. In re Pennsauken County, 2 E.A.D. 667, 671 (EAB 1988), the Board states that a control technology is "available" when "there are sufficient data indicating (but not necessarily proving)" the technology "will lead to a demonstrable reduction in emissions of regulated pollutants or will otherwise represent BACT." In re Ogden Martin Systems of Onondaga, Inc. et al, 2 E.A.D. 405, 410, note 12, (EAB 1992), the Board states that " '(a)vailable' control options are those which are known to have realistic potential for application to the regulated pollutant." In re Brooklyn Navy Yard Resource Recovery Facility, 3 E.A.D. 867, 874-875 (EAB 1992), the Board states that in determining whether removal of nitrogen-containing materials was BACT for nitrogen oxides emitted from a municipal waste incinerator, the "threshold question is whether there is sufficient indication that a separation program would reduce emissions beyond the levels achieved by the conventional control technologies already included in the permit." In addition to these decisions, Petitioners cite the TULEP proposal (Thoroughbred Ultra Low Emissions Project - an "advanced technology envelope") which TGC made to US DOE in 2001 for one of its two 750 MW units at TGS as an example of an "available" technology. P137-53.

TGC

362. TGC, on the other hand, argues that "available" means a control technology which has been demonstrated in practice, i.e. demonstrated successfully on full-scale operations for a sufficient time to be considered proven. Thus, control technologies which require

government subsidies, as well as theoretical, experimental or developing technologies, are not "available" in TGC's opinion.

Cabinet

363. The Cabinet does not ascribe any particular meaning to the term "available" in its post hearing brief.

Achievable for that source

Petitioners

364. Petitioners argue that "achievable" requires only a reasonable expectation, based on engineering principles, that the BACT limits can be met. Petitioners urge that the regulation uses the word "achievable", not "achieved", to denote the technology forcing nature of the PSD provisions, recognized in Alabama Power Co. v. Costle, 636 F.2d 323 (D.C. Cir. 1980).

TGC

365. TGC, on the other hand, contends that "achievable" in the context of BACT means an emission limit that the source can meet on a continual basis over each averaging period for the lifetime of the facility. TGC points out that an emission limit must be met under all reasonably foreseeable worst-case conditions and must take into account the seriousness of exceeding a BACT limit. TGC points to two EAB decisions which recognize that an agency has discretion to incorporate a reasonable safety factor into a BACT limit. In re Masonite Corp. 5 E.A.D. 551, 560-61 (EAB 1994); In re Three Mountain Power, LLC, 10 E.A.D. 39, 53 (EAB 2001).

Cabinet

366. The Cabinet urges that "achievable" must be read in conjunction with "for that source". "Achievable for that source", the Cabinet contends, is an inquiry into what is

achievable for the pulverized coal-fired boilers TGC proposes. As support for this contention, the Cabinet uses the definition of "source" found in 401 KAR 51:001(160)[44], which is "one (1) or more affected facilities contained within a given contiguous property line …". "Affected facility" in turn "means an apparatus, building, operation, road, or other entity or series of entities which emits or may emit an air contaminant into the outdoor atmosphere." Id. at Section 1(2). In addition, the Cabinet cites to 401 KAR 59:016[45], Section 2(1) which defines "affected facility" to mean "each electric steam generating unit that is capable of combusting more than 250 MMbtu/hr heat input of fossil fuel" and then defines "steam generating unit" as "any furnace, boiler, or other device used for combusting fuel for the purpose of producing steam …" Id. at Section 2(3). Relying on these definitions, the Cabinet urges that it considers TGC's pulverized coal boilers as the "apparatus" and thus the "source" that is to be determined for BACT.

[44] Chapter 51 is entitled Attainment and Maintenance of the National Ambient Air Quality Standards. 401 KAR 51:001, Section 1 is the definitions section for Chapter 51.
[45] Chapter 59 is entitled New Source Standards. Section 59:016 is entitled New Electric Utility Steam Generating Units.

Conclusions on the meaning of available and achievable for that source

367. As I will state throughout this Report, TGC repeatedly stated in its applications and additional submittals that the NSR Manual was the guidance it followed in performing its top-down analyses. During the formal hearing, however, TGC actually moved to exclude evidence pertaining to the Manual and for a ruling that the Manual was not binding on DAQ because it is not incorporated into Kentucky's regulations[46].

368. The U.S. Supreme Court recently stated that "(a)lthough the top-down approach is not mandated by the Act, if a state purports to follow this method, it should do so in a reasoned and justified manner." Alaska v. US EPA, 298 F.3d 814, 822 (9th Cir. 2002). I perceive this to mean that when an applicant purports to follow the NSR Manual and the agency approves this approach, neither the applicant nor the agency can later discredit the Manual by urging that their BACT analyses be adjudged or measured by a different and less stringent standard.

Available

369. In identifying candidate BACT limits, which is the first step in a BACT analysis, an applicant should take a comprehensive look at the world of control technologies. This can only be accomplished by casting a wide net to identify many potential control technologies, without consideration of whether some technologies will be later eliminated. I agree with Dr. Fox's opinion that TGC failed to identify all available technologies and failed to present any clear documentation as to why technologies were eliminated. Available control

[46] In Docket #249, I granted TGC's motion that the NSR Manual is not binding on DAQ (as agreed by all parties), but I denied TGC's motion to exclude evidence pertaining to the Manual.

options are identified in the NSR Manual in Step 1 as those "air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation." B5. The Manual states that the list should include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques, technologies employed outside the U.S., as well as technology transfer and innovative control technologies. Id.

370. "Availability" is also considered in Step 2, which involves evaluating the technical feasibility of the control options identified in Step 1. B.17. A technology which is available and applicable is technically feasible. A technology is described in Step 2 as being "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. Id.

371. The "technology-forcing objective" of the PSD regulations was noted more than 20 years ago in Alabama Power v Costle, supra at 372 (D.C. Cir. 1980) in challenges to the validity of the final PSD regulations promulgated by the EPA.

372. In keeping with the technology-forcing nature of BACT, I agree with the definition Petitioners suggest for the purposes of Step 1, i.e. for purposes of Step 1 "available" control options are those with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. I find TGC's suggested definition of "available" (technologies which have been demonstrated successfully on full-scale operations for a sufficient time to be considered proven) misses the mark. The purpose of BACT is eviscerated by TGC's narrow definition of available, under which there would be no incentive for applicants to consider any technologies which are not already considered to be proven, i.e. successfully demonstrated on full-scale operations.

Achievable for that source

373. With regard to the definition of achievability, I conclude that the Cabinet erred by failing to look to the PSD definitions in defining "that source". See Discussion and Conclusion under IGCC and CFB. "That source" refers to the "major stationary source" earlier in the BACT definition and means the entire plant, not the PC boilers, or equipment, chosen by TGC.

374. The NSR Manual describes "achievability" in Step 4. When a candidate BACT technology is eliminated, on the basis of energy, environmental or economic impacts, that technology is not "achievable". Each technology, beginning with the most stringent, is considered in this manner in determining whether it is achievable. The most stringent technology, which is not eliminated as being not achievable, is selected as BACT. Jt. #9 at B.2.

375. I conclude that a control technology is achievable for TGS when it is not eliminated in Step 4 on the basis of energy, environmental or economic impacts.

A. Clean Coal Technologies - CFB and IGCC as BACT

Overview

376. There are two types of alternative boiler designs that TGC and DAQ did not consider in their BACT analyses: CFB and IGCC. They were eliminated based on differences in boiler type and/or differences in fuel before they went through the top-down BACT process. As stated, TGC's BACT limits are based on the use of PC boilers. In sum, TGC selected PC boilers because it contends they are "the only reliable and proven combustion technology available to meet the designed 1500 MW base load, site limitations and operational requirements of the project." Jt. #33 at Red 10.

377. Petitioners contend that both IGCC and CFB are "innovative fuel combustion techniques", which are required to be considered under the definition of BACT.

378. TGC maintains that DAQ exercised its discretion not to require the use of processes or technology which would redefine the source, and reasonably rejected the use of IGCC and CFB.

379. The Cabinet contends that consideration of IGCC and CFB is discretionary. DAQ does not view IGCC as an "innovative fuel combustion technique", as included in the definition of BACT and required by the NSR Manual to be included in Step 1 of a BACT analysis. Jt. #9 at B.5. Instead, DAQ contends that IGCC would be a redefinition of the source, which it maintains is not required. The Cabinet considered CFB, but determined that TGS's PC boilers would produce emission levels comparable to or better than CFBs. Thus, DAQ rejected both IGCC and CFB.

Findings – Clean Coal Technologies

380. IGCC is a two step system. The first step is to convert coal (or other fuels) to a gas that in the second step is used as the fuel for a combined-cycle plant. 11-10-03 TE at 12-13 (Powers). CFB is a boiler in which the coal is combusted in a fluidized bed.

381. In TGC's initial BACT analysis and final BACT analysis, IGCC was not addressed, although it was present on some draft tables in TGC files. 11-6-03 TE at 82 (Fox). CFB was also not considered in TGC's original BACT analysis, but was included in its modified BACT analysis, although CFB was eliminated because of differences in fuel type and boiler. Id. Early in the permit process, however, KEC prepared two separate applications, as indicated in a letter from Bryan Handy to Peabody in October 2000. See P30, one application for eight 250 MW CFB boilers and the other with three 750 MW pulverized coal boilers.

382. On January 25, 2002, TGC counsel Kevin Finto sent a letter to DAQ's Permit Review Branch, addressing a request by the National Resources Defense Council that DAQ

remand the permit application to TGC to evaluate the availability and feasibility of implementing CFB and IGCC as BACT pursuant to the federal PSD program. The letter provides, in pertinent part:

> "while CFB and IGCC may be proven technologies, they are not suitable alternatives … and neither the law nor EPA precedent authorizes or requires the use of CFB or IGCC as BACT for TGS… TGC followed EPA's recommended 'top-down' BACT review process. TGC evaluated and provided to Kentucky a thorough analysis of all technologies available to control emissions from the proposed TGS.… The lack of CFB in the size range appropriate for the TGC application indicates that CFB technology does not meet the test of "available technology". … IGCC is a relatively new technology with only government-subsidized demonstration plants operating around the world…. A commercially viable coal-fuel IGCC has yet to be built. As with CFB, IGCC is not a commercially available technology in the size proposed for TGC and also fails the test of "available technology".
>
> Furthermore, the CFB and IGCC processes are separate and distinct technologies by which to generate electricity. They are not, in this regard, *control technologies* for the conventional pulverized-coal technology that TGC is proposing to build. This distinction is important, since EPA has made it clear that according to the Clean Air Act and the PSD permit regulations, the control technology selected as the "best available" for a proposed PSD source as a result of BACT review is "not intended to redefine the source".

Jt. #45 at Red 90-93. In the letter, TGC cites as authority the <u>Pennsauken</u> case, <u>In the Matter of Spokane Regional Waste-to-Energy</u>, PSD appeal, No.88-12 at 5, n. 7 (June 9, 1989); and <u>In the Matter of Hawaiian Commercial & Sugar Company Permit</u>, PSD Appeal No. 92-1 at 11 (July 20, 1992).

383. EPA's response to comments regarding alternative designs was that it was in DAQ's "discretion" to require a detailed evaluation of such alternative designs (CFB and IGCC) as part of the BACT evaluation. Jt. #44, at Red 18, EPA's February 26, 2002 comments. Even if DAQ decided not to exercise this discretion, EPA advised as follows:

Regardless of whether you elect to require a detailed evaluation before reaching a final BACT determination, we recommend that you include documentation from the applicant in your files providing a rationale as to why a configuration of pulverized coal boilers burning high-sulfur western Kentucky coal was selected for this project and why other design and fuel alternatives were eliminated. Id.

384. TGC's response to these EPA comments, Jt. #44 at Red 18-19, was as follows:

(e)valuation of fundamentally different alternative designs for the facility is not part of the BACT analysis….*Knauf Fiber Glass,* 8 E.A.D. 121,136 (EAB Feb. 4, 1999) (finding that BACT does not require the applicant to redefine the source; stating that the permitting authority has the discretion to require consideration of alternative processes in the BACT analysis); *In re SEI Birchwood, Inc*., 5 E.A.D. 25, 29 n. 8 (EAB 1994) (stating that the classic example of redefining a source is the substitution of a gas-fired power plant for a coal-fired plant, finding that BACT does not require the consideration of the gas-fired plant, finding that BACT does not require the consideration of the gas-fired unit as part of the BACT determination); NSR Manual at B.13 (EPA generally does not require a source to redefine its basic design).

Even if one were to look at CFB as an alternative technology, it would fail because it is infeasible for this project. Technologies that are infeasible are not considered further in the BACT analysis. CFB technology is not available for units of 750 MW. The largest one constructed commercially today is less than 300 MW. Moreover, we note that the PC technology with add-on controls proposed for TGS will have better performance than 62% of the permitted or proposed CFB technology proposed to date….

For similar reasons, integrated gasification combined cycle ("IGCC") is not appropriate technology. TGS's parent, Peabody Energy, is working with others to develop IGCC technology on a commercial basis. We understand, however, that there are no IGCC plants that truly are operable commercially – all have received Department of Energy subsidies. Moreover, IGCC technology results in some form of sulfur containing commodity product, which must be processed, stored, transported and sold. This is well outside the original design of the utility power plant that TGC has proposed.

385. In its Refined Top-down BACT Summary, included in its Addendums filed on May 29, 2002, Jt. #33, at Red 9 and 10, TGC again states that PC boilers were selected based on reliability, availability and project operational requirements. TGC notes that "(w)hile other power generating techniques utilizing coal as the fuel source exist, none are capable of providing

the generating output within the design and operational requirements of the project…." TGC then presents its evaluation of CFB boiler technology and IGCC boiler technology.

386. TGC states that CFB technology was eliminated because of size restriction on the units; the largest currently operating CFB units are 250 to 300 MW. TGC also notes that comparisons of emissions from CFB and newly refitted or proposed PC boilers indicated that the levels of emissions are similar and in some cases the PC boilers with add on controls result in lower emissions than CFB technology. Id.

387. With regard to IGCC, TGC found that there is also a size limitation on the IGCC units and the high equipment costs prevent IGCC from being commercially viable. TGC states that all current application of the IGCC technology is government subsidized. Also noted was a reliability problem and a low percentage of availability. For these reasons, IGCC was eliminated based on technical feasibility. Id. Ms. Tickner stated that although TGC considered the use of IGCC, it found that IGCC technology was not commercially available and there were a lot of operating problems with it. She acknowledged that TGC provided no actual discreet numbers as required by a BACT cost effectiveness analysis.

388. While DAQ considered CFB and IGCC, DAQ does not believe that the scope of PSD was intended to apply to the selection of technology. Jt. #33 at Red 9-10; Jt. #63 at 14; 4-14-04 TE at 20-22 (Adams); 12-5-03 TE at 144-49 (Tickner); 5-4-04 TE at 135, 235-6 (Handy). Thus, DAQ determined BACT for a pulverized coal combustion process, the process chosen by TGC. DAQ viewed IGCC as a fundamental redefinition of the project, which is not required or appropriate in the BACT review. Id. It also determined that TGS's PC boilers would produce emission levels comparable to or better than CFBs. Id.

Expert opinions on IGCC

Bill Powers[47]

389. Bill Powers, an expert in the field of environmental engineering and air pollution control technology, described IGCC as an "innovative fuel combustion technique" which is available as a viable alternative to the proposed pulverized coal system and should be judged on its merits, technical feasibility and cost effectiveness. He distinguishes the In re SEI Birchwood, Inc. case cited by TGC, supra, which states that the classic example of redefining a source as being the substitution of a gas-fired power plant for a coal-fired plant. Here, TGC is not being asked to plumb in a natural gas line and ignore the fuel that justifies the project. Instead, he states that IGCC and CFB are different processes being considered that can burn Kentucky No. 8 and No. 9 coal from the mine at the site. 11-10-03 TE at 111. Powers cited examples of IGCC technology in commercial use, among the following exhibits.[48]

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[47] Facts supporting Powers' opinions are included in his testimony.

[48] The following are exhibits cited by Powers as examples of IGCC technology:

P118-9 is the PSD/Title V permit, issued on June 7, 2001, for the Kentucky Pioneer gasification combined cycle project in Trapp, KY, showing all emission limits are lower than the emission limits for TGC.

P118-2 is a summary, published in July, 2002, by DOE, of the Wabash River Coal Gasification Repowering Project in IN, the first integrated gasification combined cycle project of size (250MW) in the US. (continued on next page)

P118-20 is a summary of the coal gasification process used at Eastman Chemical Company in Kingsport, TN, a project that became operational in 1983 and underscores that coal gasification is a mature technology.

P118-3 is a 2001 summary of the Tampa Electric IGCC project, which began as a five-year demonstration project and then achieved the goal of becoming a full commercial operation. The summary underscores the need for a spare gasifier at any commercial project. There were four so-called demonstration to commercial projects, two in the US (Tampa and Wabash) and two in Europe (in the Netherlands and in Spain), which demonstrated the commercial viability of the IGCC technology.

P118-4 is a description of the William Alexander IGCC plant in Holland, an overview of the project and experience, dated March, 2002.

P120-7 shows that by letter issued on March 6, 2002, the Georgia Department of Natural Resources was requiring the Longleaf Energy Station application, a coal-fired power plant, to include an analysis of IGCC.

P118-30 is an October 8, 2001, presentation at the Coal Technologies annual conference on the current capacity and sole capacity of gasification around the world and a projection of future growth. The presentation states that the South Africans are the leaders in the amount of synthetic gas produced, with the US being number two and increasing rapidly. China is also rapidly expanding its use of IGCC. Each one of the three South African Sasol plants with a combined cycle power plant could produce about double the power that TGC projects at 1,500 MW.

P118-31 is a paper presented by a representative from Sasol at the Gasification Technologies Conference in October 2001 regarding issues when handling high ash coals.

> At this moment in time, there have been few coal fired power plants built in the United States in the last decade, possibly the last two decades, and we're at a point in time where the – around the country we're gearing up to build more coal fired power plants, and integrated gasification combined cycle is really the technology that allows coal to be burned at a level that is essentially as cleaned as a gas turban combined cycle power plant. 11-10-03 TE at 14 (Powers).

390. In Powers' opinion, IGCC was demonstrated in practice, i.e. put in a full scale application, at the time the TGC permit was issued. He relies on the experience in coal gasification of Eastman in Kingsport, TN (successfully operating for 20 years) and Sasol (South African projects operating for 20 years) and the demonstration projects at Wabash, IN, and Tampa, FL. IGCC was described by Powers as a cleaner technology than pulverized coal

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P118-5 is a document dated May, 2001, entitled Environmental Enterprise, Carbon Sequestration using Texaco Gasification Process presented at the First National Conference on carbon sequestration showing that there are numerous other commercial coal gasification projects around the world.

P118-17 is a presentation made at the 19th Annual Pittsburg Coal Conference on September 23-27, 2002, entitled An Environmental Assessment of IGCC Power Systems, showing historical performance of IGCC.

P118-16, a US DOE report entitled Gasification Markets and Technologies – Present and Future, dated July 2002, is a compilation of interviews with some 22 different companies involved with coal gasification.

technology, more efficient at burning coal (it emits less pollution per ton of coal burned and also has an output of more electricity per that ton of coal).

391. In summary, Powers explained that the Eastman IGCC plant in Tennessee has achieved spectacularly high availability rates on its gasification process because it has a spare gasifier. The gasification unit was on line 98% of the time. Thus, the reliability issue is addressed with a spare gasifier, which adds a nominal additional expense. An IGCC unit in Florida has an availability of 88.7% and 84.2% without a spare gasifier, higher than the 75% claimed by TGC.

392. No rebuttal testimony was offered by the Cabinet or TGC to Powers' testimony.

Parties' Arguments on Clean Coal Technologies

Petitioners

393. Petitioners urge that the plain language of the definition of BACT, 401 KAR 51:017, Section 1(8), as well as the legislative history show that DAQ was required to consider IGCC and CFB under BACT. Petitioners maintain that both IGCC and CFB are "innovative fuel combustion techniques", as that term is used in the definition of BACT.

394. Petitioners urge that the legislative history of the term "innovative fuel combustion techniques" is instructive. When Senator Huddleston of Kentucky added the term "innovative fuel combustion techniques" to the definition of BACT, he included gasification and fluidized bed combustion in the definition of innovative fuel combustion techniques when he stated:

> Mr. HUDDLESTON. Mr. President, the proposed provisions for application of best available control technology to all new major emission sources, although having the admirable intent of achieving consistently clean air through the required use of best controls, if not properly interpreted may deter the use of some of the most effective pollution controls. The definition in the committee bill of

> best available control technology indicates a consideration for various control strategies by including the phrase "through application of production processes and available methods systems, and techniques, including fuel cleaning or treatment. **And I believe it is likely that the concept of BACT is intended to include such technologies as low Btu gasification and fluidized bed combustion.** But, this intention is not explicitly spelled out, and I am concerned that without clarification, the possibility of misinterpretation would remain. It is the purpose of this amendment to leave no doubt that in determining best available control technology, all actions taken by the fuel user are to be taken into account – be they the purchasing or production of fuels which may have been cleaned or up-graded through chemical treatment, **gasification**, or liquefaction; use of combustion systems such as **fluidized bed** combustion which specifically reduce emissions and/or the post-combustion treatment of emissions with cleanup equipment like stack scrubbers. The purpose, as I say, is just to be more explicit, to make sure there is no chance of misinterpretation.

95th Congress, 1st Session (Part 1 of 2) June 10, 1977 Clean Air Act Amendments of 1977 A & P 123 Cong. Record S9421 (emphasis added).

395. Petitioners urge that the above statement makes clear that gasification and fluidized bed combustion are included in the definition of innovative combustion techniques. They argue that DAQ and TGC are trying to rewrite the law to make PSD an equipment oriented program rather than a site oriented program by its narrow reading of "achievable for that source".

396. Petitioners also cite to the testimony of Powers, president of a consulting firm involved in emissions testing, BACT analyses, and control technology, and testimony by Dr. Fox, both of whom testified to the benefits of IGCC and CFB technology.

Cabinet

397. The Cabinet, as discussed earlier in the Count (under the discussion of "achievable for that source"), urges that it is not required to consider or evaluate IGCC and CFB because the BACT definition considers what is "achievable for that source", and here, the source are the PC boilers TGC has proposed to build. As stated earlier, the Cabinet uses the definition

of "source" found in the 401 KAR 51:001 definitions and New Source Standards definitions to conclude that TGC's pulverized coal boilers are the "apparatus" and thus the "source" that is to be determined for BACT.

398. The Cabinet maintains that IGCC is not an innovative fuel combustion technique, but instead would be a redefinition of the project which is not required or appropriate under the PSD regulation. In response to Petitioners' contention that when Senator Huddleston added the term "innovative fuel combustion techniques" to the definition of BACT, he included gasification and fluidized bed combustion in the definition of innovative fuel combustion techniques, the Cabinet argues that Senator Huddleston did not say that coal gasification must be chosen or even considered. Instead, the Cabinet contends that Senator Huddleston believed that BACT should be a decision process with many possible outcomes, so long as the end-of-the-pipe emissions from the source or modification are reduced to acceptable levels for the source.

399. The Cabinet contends that although it is discretionary whether it even considers CFB, it did consider CFB and found that PC boilers "produce emission levels comparable to or better than" fluidized bed BACT determinations. Jt. #63, p 14. Adams testified that CFBs were rejected not because they would redefine the source (as DAQ believed about IGCC), but because of technical concerns. DAQ found there were technical problems with the largest CFB boilers at the time, 300 MMbtus. Thus, they were found to be technically infeasible because of the size considerations. 4-14-04 TE at 202 (Adams).

TGC

400. TGC's position is that IGCC and CFB are "separate and distinct technologies" by which to generate electricity. They are not, in this regard, control technologies for the conventional pulverized-coal technology that TGC is proposing to build. This distinction is

important, since EPA has made it clear that according to the CAA and the PSD permit regulations, the control technology selected as the "best available" for a proposed PSD source as a result of BACT review is "not intended to redefine the source". TGC185 at KEC006498-6501; Jt. #45 at Red 90-93 (both exhibits are a letter from TGC counsel to DAQ's Permit Review Branch, cited in the Findings).

401. TGC concurs with the Cabinet in stating that DAQ considered TGC's analysis of CFB and applied its own knowledge of CFB in determining that CFBs were not technically feasible due to the size.

402. TGC maintains that IGCC is more like a natural gas-fired plant as opposed to a coal-fired plant, 4-13-04 TE at 68 (Adams), and is "innovative technology"[49] at the size proposed for TGS. They urge that it is neither cost effective nor reliable. TGC cites two administrative decisions issued after the TGC permit was issued which determined that IGCC is not yet a mature, reliable or economic technology alternative, In Re Tuscon Elec. Power Co.'s Application for a Hearing Regarding a Fourth Generating Unit Located in Springerville, AZ, Docket No. L00000C-77-0030 et al at 50 (November 1, 2002) ("IGCC is not yet a mature, reliable or economic technology alternative".) and Final Decision of the Public Service Commission of Wisconsin on Application for Certificate of Public Conv. and Necessity for the Elm Road Generating Station, 05-CE-130 at 26 (November 10, 2003) ("IGCC technology, while promising, is still expensive and requires more maturation.") TGC also points out that in P118-16, a US DOE Report on Gasification technologies dated July 2002, in the Executive Summary, iii, states that "(r)eliability, availability, and maintainability (RAM) must increase to reach

[49] "Innovative technologies" are distinguished from "innovative fuel combustion techniques". Innovative technologies not required in Step 1 of the NSR Manual. Jt. #9 at B.12.

acceptable industry thresholds and to eliminate redundancies contributing to high capital and EPA costs."

Petitioners' reply

403. In reply, Petitioners point out that because Kentucky's definition of BACT is at least as stringent as the federal definition, a pronouncement by Congress (Sen. Huddleston's comments) on the definition of BACT is controlling in this proceeding. See 40 CFR Section 51.166(b).[50]

404. In response to the Cabinet's argument that BACT does not require consideration of IGCC and CFB, Petitioners urge "for that source" in the definition of BACT is referring not to the PC boilers TGS has proposed, as the Cabinet contends, but instead is referring to "proposed major stationary source" found earlier in the same sentence. "Major stationary source" is defined in the PSD definitions as a "stationary source", 401 KAR 51:017 Section 1(25)(a), which in turn is defined as a "building, structure, facility, or installation." Id. at Section 1(38). The definition of "building, structure, facility, or installation" is then defined in Section 1(9) as "all of the pollutant emitting activities which belong to the same industrial

[50] All state plans shall use the same definitions as the federal definitions, unless the state specifically demonstrates that a deviation from the federal definition wording is more stringent or at least as stringent as the federal definition. Kentucky's definition is at least as stringent.

grouping, are located on one (1) or more contiguous or adjacent properties, and are under the control of the same person …" Under these definitions, Petitioners argue "that source" in the BACT definition is a facility which engages in the generation, transmission and/or distribution of electric energy for sale, not a pulverized coal boiler or a coal-fired power plant. Petitioners point out that terms in the BACT definition are defined in the PSD regulation definitions found in 401 KAR 51:017. If not defined there, they are defined in 51:001. Thus, because "stationary source" is defined in 51:017, the definition of "source", as cited to by the Cabinet from 51:001, is not applicable, nor is the definition of "affected facility" in 401 KAR 59:016 applicable.

405. Petitioners cite to a recent law review article by an EPA official – Gregory B. Foote, an assistant general counsel with the EPA, who in his individual capacity wrote Considering Alternatives: The Case for Limiting CO2 Emissions From New Power Plants Through New Source Review, 34 ELR 10642 (Aug. 2004). In Section II of the article, entitled "Redefining the Source", he explains why there is no basis in law for excluding consideration of alternatives that would "redefine the source" as proposed by a permit applicant. Id. at 10643. In a review of EAB precedents, Foote demonstrates that "permitting authorities cannot lawfully accept the design or location of a proposed source as a fait accompli. Rather, the proposal is subject to public debate, and permitting authorities must justify on the record of the permit proceeding any decision to reject reasonable alternatives to the proposed source". Id. at 10651. Foote acknowledges that in the Pennsauken case, supra, the Administrator ruled that BACT permit conditions are imposed on the source as the applicant has defined it. The following year, In re Hibbing Taconite Co., 2 E.A.D. at 838, 1988 EPA App. LEXIS 27, involved a permit for modification of a gas-burning boiler to switch to petroleum coke. EPA ruled that the permitting agency had failed to justify its cursory rejection of continued use of gas on economic grounds,

since the mere fact of the plant's prior history showed gas to be a viable alternative. If only these two cases are considered, Foote suggests that one might conclude that EPA believes there is a line beyond which alternatives to a proposed source constitute "redefining" the source, and that as such they are beyond the scope of a PSD proceeding.

406. However, he points out that more recent EAB decisions contravene that reading and make it clear that even if alternatives brought forward by commenters constitute "redefining" the source, they are within the scope of the PSD proceeding. In addition, when the agency rejects a proferred alternative, the rejection is an exercise of discretion which is reviewable to determine whether such discretion was exercised reasonably or whether it was an abuse of discretion. At page 10652 of his article, he cites to the following quote from <u>In re Kendall New Century Development</u>, PSD Appeal No. 03-01, ELR ADMIN. MAT. 41261, 2003 EPA App. LEXIS 3, at 30 n. 14 (EAB Apr. 29, 2003).

> We have previously noted that the Agency's PSD regulations governing permit conditions do not require that a permitting authority consider "redefining the source" as a means of reducing emissions … However, "although it is not EPA's policy to require a source to employ a different design, redefinition of the source is not always prohibited. This is a matter for the permitting authority's discretion". <u>Knauf Fiber Glass</u>, 8 E.A.D. at 136. In order to obtain review of a permit issuer's decision not to conduct a broader BACT analysis that would include redefinition of the source, a petitioner must show a good reason in the circumstances of the case for curtailing the permit issuer's discretion or that the permit issuer abused this discretion.

407. Foote points out that the standard articulated by the EAB in addressing alternatives to the proposed source presumes as an initial matter that the permitting agency must have authority to consider redefining the source in response to criticism articulated by commenters who propose alternatives. It would be illogical and contrary to the CAA statutory language and legislative purposes, to conclude otherwise. He points out that if states disclaim

authority to consider alternatives, they could by the same reasoning reject traditional add-on control devices that exceed some predetermined "disproportionate cost" threshold without providing a case-specific rationale for that decision. The Supreme Court recently found that to be arbitrary and thus unlawful. Alaska Dep't of Envtl. Conservation v. EPA, 124 S. Ct. 983, 1007-09, 34 ELR 20012 (2004). Foote points out that in Kendall, the EAB pointed out that the state cannot abuse its discretion by a complete failure to consider statutorily mandated factors such as alternatives to a proposed source generally. Likewise, he suggests that a court which reviewed the EAB's generally narrow standard for granting review of agency permitting decisions (only in cases of clear error) would use the arbitrary and capricious standard. The court would refuse to uphold the rejection of a proferred alternative to the proposed new source if such rejection, considering the administrative record as a whole, constituted an abuse of discretion or otherwise was arbitrary and capricious.

408. Foote next examines the issue of what would constitute reasonable, as opposed to arbitrary, state consideration of alternatives. EAB precedents show that the degree of discretion the agency has to accept or reject alternatives is a function of the persuasive value of those alternatives. The more obvious and proven the alternatives are, the greater consideration is merited by the agency.

409. Next, following the Foote article, Petitioners offer more support for the conclusion that a "source" under the PSD program is not the particular boiler the applicant is proposing (as the Cabinet maintains) but instead is the facility the applicant is proposing with the combustion technology subject to change based on a BACT analysis. Alabama Power Company v. Costle, supra at 396 ("'facility' and 'installation' defined broadly enough to encompass an entire plant"); Chevron, 467 U.S. at 840 ("EPA regulation promulgated to implement this permit

requirement allows a State to adopt a plantwide definition of the term ‘stationary source’”). Kentucky has adopted the same definition of “building, structure, facility, or installation”. See also the recent Eleventh Circuit decision, Sierra Club v. Leavitt, 368 F. 3d 1300 (11th Cir. 2004)[51], a case in which the Sierra Club attempted to block Oglethorpe Power Corporation from obtaining a Title V/PSD permit for a new power plant in Georgia under Georgia’s SIP which provides a permit cannot be obtained for a new major stationary source if a permittee owns or operates an existing major stationary source that is in violation of the CAA. The issue was whether Oglethorpe could obtain a permit for a new power plant when another power plant Oglethorpe owned was in violation. EPA defended the action by urging that while Oglethorpe owned an interest in some of the boilers at the noncompliant power plant, it did not own the boilers that were noncompliant. Thus, EPA urged that Oglethorpe did not own a noncompliant major stationary source. The Court found that “(a)lthough the EPA Order did not explicitly acknowledge doing so, the agency appears to have determined that the Georgia Rule allows breaking major stationary sources into constituent parts with compliance determined individually. But that interpretation requires

[51] The firm of Hunton and Williams, TGC’s counsel in this case, represented the power plant. Id. at 1300.

giving the term 'major stationary source' its ordinary meaning in its first appearance in the rule and redefining or ignoring it in its second appearance in the very same sentence." Id. at 1306. EPA's approach in giving two different meanings to "major stationary source" in a single regulatory sentence was arbitrary and capricious. The Court thus vacated the EPA order and remanded the case to the agency for further review. Id. at 1309. Petitioners point to Citizens for Clean Air v. U.S. EPA, 959 F.2d 839, 849 (9th Cir. 1992), in urging that the Cabinet's reliance on the NSPS (New Source Performance Standards) programs' regulations to define a term out of the PSD program is in error. The Court in the Citizens case explains that NSPS focuses on the particular apparatus which is a component in a stationary source while the "PSD program covers the whole stationary source, and focuses on where the plant will be located and its potential effect on its environs. The PSD program is therefore site oriented." Petitioners point out that the same distinction made by the court in the Citizens case between the PSD program and the NSPS program was made by an attorney with the firm representing TGC, the Hunton and Williams firm in a brief written in defending a citizen enforcement action against a power plant in Arizona. Grand Canyon Trust v Tuscon Electric Power Company, CV-01-2189-PCT-EHC (D.Az. Dec. 16, 2002). Although this attorney is a lead litigator for the power industry in CAA issues, he recognized that the PSD program is site oriented.

410. Petitioners demonstrate that IGCC is available as a result of the Eastman plant in TN and plants in S. Africa, as neither of these is a DOE demonstration project. Petitioners also distinguish TGC's reliance on P118-16, "An Industry Perspective" on Gasification Markets and Technologies "Present and Future", July 2002, noting that the purpose of the DOE report was "to support future budget requests". Id. at 53. Petitioners point out that the report notes that single gasifier systems have now reached their design performance. Id. at 21. The report continues by

noting that because financial institutions are risk averse, they require major gasification projects to have multiple gasifiers (trains) or sparing to ensure reliability targets are achieved. Id. Despite the cost for spare gasifiers, the report states that IGCC plants are competitive in "niche applications where feedstock costs are low." Id. Powers explained that TGS is a niche market because it is a mine mouth plant, which will not pay the cost of transporting coal. The report concludes that coal based projects are feasible at a coal cost of about $1/MMbtu. Id. at 8. Because TGS is a mine mouth plant, its coal cost would be below the $1/MMbtu level. 11-10-03 TE at 102:12-24 (Powers). Petitioners urge that in a case-by-case analysis, the report is support for IGCC being available and economically feasible for TGS.

411. Petitioners also distinguish the two public utility commission cases on which TGC relies. The Wisconsin decision was recently vacated on appeal. Clean Wisconsin, Inc. v Wisconsin Public Service Commission, Case No. 03CV3478 (Dane Co. Ct. Nov. 29, 2004) at slip op. p 16. Moreover, Petitioners point out that a public utility commission analysis has different standards than a PSD review. The focus of a public utility commission analysis is providing the cheapest cost electricity for customers, while a BACT analysis is not designed to achieve the cheapest cost electricity for customers. In addition, neither the Arizona nor the Wisconsin facilities are mine mouth facilities. Petitioners also point out that whether a technology is mature is not relevant under BACT, contrary to the Arizona Corporation Commission's decision which states that IGCC is not a mature, reliable or economic technology.

412. In conclusion, Petitioners strongly urge that the Cabinet was wrong as a matter of law in believing that it could not consider BACT emission limits achieved through the use of IGCC or CFB boilers because TGC proposed PC boilers.

Conclusions on Clean Coal Technologies

413. The Cabinet erred as a matter of law by concluding that it lacked authority to require TGC to include IGCC and CFB in its BACT analysis. The Cabinet's reliance on the definition of "source" as referring to the PC boilers proposed by TGC is too narrow and is contrary to the PSD program's focus, which is site oriented, not equipment oriented. As argued by Petitioners, "that source" in the BACT definition refers to "major stationary source", which is the entire facility TGC is proposing. Alabama Power, supra at 396.

414. Clearly, the Cabinet had authority to require TGC to do a BACT analysis on both IGCC and CFB. This is clear from the legislative history of the amendment of the BACT definition, which adds the term "innovative fuel combustion technique" to the definition of BACT, with comments by Senator Huddleston indicating that gasification and fluidized bed combustion are included within the term "innovative fuel combustion technique".

415. Indeed, as stated in the Considering Alternatives law review article, it would be contrary to the CAA for a permitting agency not to be able to consider a redefinition of the source in response to commenters who are proposing alternatives. In exercising its discretion to consider IGCC and CFB, it was incumbent on DAQ to consider the persuasive value of those alternatives. I conclude that a remand is appropriate to require DAQ to exercise its discretion to consider IGCC given the considerable evidence adduced as to the viability of IGCC.

416. As with IGCC, it was incumbent on TGC to include CFB in its BACT analysis, rather than excluding CFBs as technically infeasible at 750 MW, the size boiler chosen by TGC. Although DAQ stated that "(e)ven if TGC were to construct 10 smaller (C)FB (fluidized bed) units, instead of two large fired bottom units, the controls being installed produce emission levels comparable to or better than previous FB BACT determinations", Jt. #63 at 14, DAQ did not produce its analysis to support these conclusions. In addition, Jt. #33 at Red 21, TGC's revised

BACT table, shows CFB units with emission limits lower than TGC, i.e. the best emission limit for a CFB for SO_2 is 0.013 lbs/MMbtu (EnviroPower – KMP), which is lower than TGC's permit. The best emission limit for a CFB for NO_x is 0.07 lbs/MMbtu (Calla facility), which is lower than TGC's permit. The best emission limit for a CFB for PM is 0.015 lbs/MMbtu (EnviroPower IL – Benton and EnviroPower – KMP), which is lower than TGC's permit limit. Indeed, the Calla facility, which is a CFB plant, had a lower limit for SO_2, NO_x, PM and PM_{10}. Moreover, PR319 also contains a number of CFB units that are permitted at levels below TGC's permit. Shepherd's NPS chart shows the AES Warrior Run plant, with CFB, with a NO_x limit of 0.07 lbs/MMbtu in 1994. P160-2 at Table 2.b. DAQ's conclusion that the controls being installed at TGC's PC boilers produce emission levels comparable to or better than CFBs is challenged by these exhibits.

417. For the foregoing reasons, I conclude that DAQ erred as a matter of law by concluding that it lacked authority to require TGC to include IGCC and CFB in its BACT analysis. Based on evidence adduced by Petitioners, on remand DAQ should require TGC to include IGCC and CFB in its BACT analysis, and then DAQ should exercise its discretion to accept or reject these analyses.

B. Coal Washing as BACT

Overview

418 DAQ concluded that energy, environmental and economic impacts preclude coal washing as BACT to reduce SO_2 at TGS.

419. TGC and DAQ believe that this was a reasoned decision. Petitioners contend that DAQ's decision was contrary to fact and law.

Findings on Coal Washing

420. TGC did not initially include an analysis of coal washing in its BACT analysis. However, at the request of DAQ and in response to comments from EPA and NPS, TGC provided the following evaluations on coal washing describing the environmental, energy and economic impacts, and including a cost analysis:

a. Jt. #56 at Red 30-31 (December 12, 2001) – In this response to NPS's request to address the BACT option of coal washing, TGC explained that coal washing creates two waste streams – gob (the solids portion of the waste removed in the washing) and slurry (a combination of smaller particles and fine coal that stay in suspension of the washing wastewater). Washing the coal is estimated to create 20% more total waste than burning the coal raw. The gob would be disposed of in a landfill structure and the slurry pumped to dewatering ponds. TGC stated that these impoundment structures create environmental concerns. Coal washing would add as much as $20 to $30 million in capital costs. Thus, TGC concluded that coal washing was undesirable, uneconomical and does not represent BACT. Id. at Red 31. A raw coal versus clean coal analysis was attached at Red 45-48.

b. TGC185 at KEC006418-20 (February 28, 2002) - In response to additional NPS concerns, TGC pointed out that even if TGS washed its coal, it would not achieve sulfur levels claimed by NPS (sulfur content reduced to 1.84%). TGC also states that contrary to NPS comments, in its economic analysis of coal cleaning it did account for impacts to the power plant capital, operating and maintenance costs resulting from the use of raw versus washed coal. However, even with the costs savings, it found the marginal cost for coal washing is $28,117 per ton of SO_2 removed, which in its opinion is not BACT.

c. Jt. #44 at Red 15-18 (March 12, 2002) – In response to EPA comments, TGC responds that there is no onsite location for disposal of coal washing byproducts. Costs associated with offsite disposal are provided. TGC compares the technology selected for control of SO_2 (wet FGD and ESP on unwashed coal) which removes 409,000 tons of SO_2 emissions at an annualized cost of $397 million to coal washing which removes 101,500 tons per year at an annualized cost of $62 million more per year, which TGC maintains is an incremental cost analysis of $69,000 per incremental ton removed. In response to a question about beneficial effects in addition to removal of sulfur, TGC states that coal washing would result in no incremental reduction in particulate emissions, and the effect on metals is not clear.

d. Jt. #38 is a letter from Ms. Tickner dated May 24, 2002 – This letter to DAQ Director Lyons, reviews TGC's position on coal washing. Jt. #38 also includes a report submitted by Dr. Rick Honaker, associate professor in the Department of Mining Engineering at the University of Kentucky, which concludes that coal washing was technically and economically infeasible for the following reasons:

* the quality of coal made it infeasible to achieve the SO_2 removal percentage cited by NPS
* adverse environmental impacts
* significant energy loss
* high incremental costs
* coal washing would not produce significantly greater SO_2 reductions than already achieved
* no environmentally safe locations to impound wastes. Attachment to Jt. #38.

However, in summary, the report states that total sulfur reductions up to nearly 35% can be achieved with relative small effects on the overall cost per clean ton. Sulfur reductions greater than 35% sharply increase the cost of cleaning with minimal additional impact on total sulfur reduction.

e. Jt. #33 at Red 43-48 (May 29, 2002 Addendums) – TGC states that coal washing is not technically feasible due to safety concerns. Energy loss with coal washing can be 30 –

35%, resulting in the need for additional coal to be mined (approx. 25% more), with plant operating costs increased as much as $40 million per year in total cost ($5 to $6/clean ton of coal). TGC reviews the environmental concerns with the waste streams and also states that vendor guarantees on lbSO_2/MMbtu are identical whether raw or washed coal is used. TGC states that coal washing is not a "dominant" technology when compared to the technologies selected (i.e., the wet FGD and ESP provide greater emission control at lower annualized costs). Thus, TGC states that it is appropriate to look at incremental rather than average cost per ton of SO_2 removed. TGC finds the additional cost of coal washing to the wet FGD and ESP technologies has an unacceptable incremental cost of approximately $69,000 per incremental ton removed. "Even if coal washing were feasible for TGS, it would be rejected as BACT since it adds nothing to the ultimate emission control and reduces efficiency, increases environmental risks, and adds significant costs".

f. Jt. #17 at Red 99-101, 134-45 (September 16, 2002) – In response to comments, TGC again states that coal washing would be technically infeasible and would produce unacceptable environmental impacts and safety concerns. Referring to Dr. Honaker's report, TGC states that if coal were washed to the extent suggested by commenters, the coal would have to be crushed entirely (to dust) and over half of the coal would be lost. Thus, coal washing at TGS has unacceptable energy and economic consequences. Dr. Honaker provided an additional report analyzing dry coal washing at Red 134-45, which in summary concludes that dry coal washing removes less SO_2 than wet coal washing at higher capital cost. He also concluded that there are no facilities with TGS's throughput (1,200 tons/hour) that use dry coal washing processes.

421. EPA and NPS filed the following comments during the permitting process which address coal washing:

a. EPA commented on February 26, 2002:

The applicant's analysis of coal washing points out the potential adverse environmental effects resulting from solid and liquid wastes produced by coal washing. While this observation is valid, we note for your attention that coal washing is commonly practiced at many mines and that the generation of waste materials does not mean necessarily that coal washing should be eliminated from further consideration. P23 at p.8, comment 2.c.

The cost data provided for coal washing appears to concentrate on the incremental cost of controlling SO_2 emissions by washing coal. For a complete evaluation of the coal washing option, we recommend that KDAQ obtain or develop an estimate of total cost effectiveness (annualized dollars per ton removed) for coal washing plus FGD. Although the incremental cost effectiveness may be high, the total cost effectiveness may be reasonable. P23 at p.8, comment 2.d.

b. NPS sent an email to DAQ on April 29, 2002:

The email was sent by Dee Morse, but composed by Shepherd, and states, in part:

(w)e still believe that TGS can effectively use coal washing to lower SO_2 emissions from their proposed facility. The limited information provided by TGS has not changed our position on this…

If we compare TGS to the whole range of new boilers proposing to burn coal close to our Class 1 areas, the TGS emission rates fall out as above the median value for SO_2 and equal to the median values for NO_x and PM. However, since BACT is supposed to consider the current state-of-the-art, if we compare TGS to the lowest levels we are seeing proposed or in operation, TGS falls short, as we have repeatedly noted in our comments to KDAQ. TGS's proposed BACT was great back in early 2001, but it has since been eclipsed by its competitors….

We again ask TGS to provide better explanation for the economic feasibility of coal washing, the information they provide has no explanations for their calculations, therefore it is difficult to determine how they arrive at their conclusions that coal washing is economically infeasible. P160, exh. 15.

Shepherd said the questions in this email were never addressed. P160 at 79:17-19.

422. Shepherd again emphasized in his deposition that TGC's analysis of coal washing was insufficient. P160 at 31. "(E)ven though Thoroughbred might be doing a pretty good job of

taking the sulfur out of the flue gas, the question we had is, is there some way that we could reduce the sulfur input to the boiler? And we think that coal washing really deserved a more thorough analysis". Id. at 31 at 10-15. He also believed that coal washing would achieve some 20% reduction in mercury. Id. at 81: 12-19. Shepherd believed that a complete BACT analysis would look at the issue of coal washing in more depth. He cites an EPA report to Congress stating that 77% of eastern bituminous coal is washed. P160 at 16:20-23.

423. DAQ's determination of coal washing is found in the final SOB and in its final response to comments:

> a. In the final SOB, Jt. #7 at 22, the following conclusion is the only statement DAQ makes regarding coal washing:
>
> The applicant also submitted analysis on coal washing as a method of reducing SO_2 emissions. Based on the information provided the Division concurs that the adverse environmental, energy, and economic impacts are unacceptable, therefore coal washing is not considered BACT for this facility.
>
> b. The Cabinet's final response to comments, which were issued with the final SOB, includes the following:
>
> TGS has submitted additional information available prior (to) the second public hearing showing that coal washing has only minor benefit in the reduction of sulfur dioxide, PM and Hazardous Air Pollutants. The Division's review found that the relevant energy, environmental and economic impacts are substantial and preclude washed coal as a viable option.
>
> CATF (Clean Air Task Force) discusses in details the types of coal washing techniques not covered in TGS's application and submittals, contending that the exclusion of "dry washing" and other techniques to remove pyrite and inerts does not meet the requirements of BACT. While the Division agrees that CATF makes valid technical points, the Division's decision to preclude coal washing was made based on the required top-down BACT approach. Jt. #63 at 14.

424. Dr. Fox testified with regard to two documents which show coal washing as being cost effective and as reducing the concentration of many trace metals.

425. P137-12 is a document from TGC's discovery document production entitled Estimated Cost Effectiveness of Coal Cleaning for Sulfur Dioxide Removal. Dr. Fox described this document as a cost-effectiveness analysis for coal cleaning for SO_2 removal. She said the analysis is "done according to the procedure laid out in the OAQPS (EPA Office of Air Quality Planning and Standards) Cost Manual, an EPA cost-estimating bible that is used in doing cost-effectiveness analyses under the top-down BACT process. And what it shows is the cost-effectiveness of the use of coal cleaning for removing sulfur dioxide is $411 per ton of SO_2 removed. That is a very low number. Generally the cutoff for cost-effectiveness is up in the range of $2,000-5,000 a ton. This is very, very low". 11-13-03 TE 137:21-138:6. This document was not provided to DAQ.

426. P137-44 is a fax from Peabody to Bryan Handy at KEC showing an analysis of raw Seam 8 and washed Seam 8 coal. The analysis shows that coal washing reduces the concentration of many of the trace metals. 11-13-03 TE at 137:19-142:1-8. (Fox).

Parties' Arguments on Coal Washing

Petitioners

427. Petitioners incorporate their arguments in opposition to TGC's motion for partial directed recommendation on Count 9, in which they argue that the benefits of coal washing with regard to mercury, PM, and NO_x were not considered; they suggest ways to mitigate adverse environmental impacts of slurry impoundments; and they urge that the cost analysis was flawed. They point out that TGC's own coal washing expert, Dr. Honaker, stated that coal washing could

remove 30 to 34% of the sulfur in the coal before the cost curve started increasing rapidly. P160 at 31:19.

Cabinet

428. The Cabinet states that its decision to preclude coal washing was made based on the required top-down BACT approach. Jt. #63 at 14. DAQ found "the relevant energy, environmental and economic impacts are substantial and preclude washed coal as a viable option." Id. The Cabinet states its serious ongoing environmental concerns following the breach of the 72-acre slurry impoundment at Martin County Coal and also cites TGC15, an article in the Sierra Club newsletter opposing slurry impoundments.

TGC

429. TGC argues that while Petitioners may raise questions about coal washing, they fail to prove that DAQ's determination as to coal washing was arbitrary and capricious. TGC points out that Petitioners offered no expert on coal washing. TGC urges that there are economic, energy and environmental reasons which led to DAQ's reasoned determination that coal washing was not feasible. Coal washing produces an additional waste stream called coal slurry, and the disposal of this coal slurry raises serious environmental concerns. 4-14-04 TE at 25-27 (Adams). TGC concurs with the Cabinet in pointing out that the Sierra Club itself has called for a permanent ban on coal slurry impoundments at or near underground mine works due to their harmful environmental impacts. TGC15.

Petitioners' reply

430. In reply, Petitioners point out in their post hearing reply brief that because coal washing is a control technology which is widely used "the bar is very high for eliminating it as technically infeasible, in the absence of unusual circumstances." Petitioners urge that TGC was not able to provide reasons why coal washing is feasible for other similar facilities, but not TGS.

431. Some 77% of eastern bituminous coal is being washed. P160 at 16:20-23. Peabody washes coal at its Highland mine and Freedom mine, both in Kentucky, and Peabody sells the washed coal. 12-4-03 TE at 116:1-9 and 12-5-03 TE at 126:2-4 (Tickner). Peabody also had a coal washing operation with impoundments in the past at the adjacent Gibraltar Mine. 12-10-03 TE at 173:23-174:13 (Tickner).

432. In rebuttal, Petitioners point out that the revised application for the Cash Creek plant in Kentucky, which was prepared by KEC, shows that coal washing is being proposed as environmentally acceptable and cost-effective. 6-1-04 TE at 241-243 (Fox); PR305 at 4-1.

Petitioners question why coal washing is cost effective for the Cash Creek facility, which will fire washed western Kentucky coal, but not effective for TGS.

433. Although DAQ states that its decision to preclude coal washing was made based on the "required top-down BACT approach", Jt. #63 at 14, Petitioners urge that the Cabinet failed to follow the NSR Manual in rejecting this widely used control technology. Under Step 4, the Manual states that:

> The determination that a control alternative is inappropriate involves a demonstration that circumstances exist at the source which distinguish it from other sources where the control alternative may have been required previously, or that argue against the transfer of technology or application of new technology … In showing unusual circumstances, objective factors dealing with the control technology and its application should be the focus of the consideration. The specifics of the situation will determine to what extent an appropriate demonstration has been made regarding the elimination of the more effective alternative(s) as BACT. **In the absence of unusual circumstance, the presumption is that sources within the same category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same category.** Jt. #9 at B.29. (Emphasis added).

434. Tickner cited land constraints (as an unusual circumstance) stating that there are essentially no locations where it would be environmentally safe to place an impoundment in proximity to the plant site because a large portion of the site has been undermined by prior underground mines, which would render this surface unsuitable. She estimates that 1,000 acres would be needed for a coal washing facility. Adams, however, testified that the land constraints, which TGC relies on, for placement of a slurry impoundment were not a valid reason for precluding coal washing. 4-15-04 TE at 14:22-15:8.

435. Petitioners urge that TGC should have considered placing a slurry impoundment a little farther from the TGS site, and pointed out that TGC included costs for off-site disposal in its own cost analyses. Jt. #44 at 13. TGC acknowledges that there is a wildlife management area,

which is leased to the Kentucky Fish and Wildlife Service, on the opposite side of the road from the plant, which has not been undermined. 12-5-03 TE at 8:17-10:2; P176- location map. The leases indicate that this property exceeds the 1,000 acres Tickner said would be required for a coal washing facility. PR236. 12-5-03 TE at 10:5-8 (Tickner).

436. Both TGC and the Cabinet refer to the Martin County impoundment failure to support their contentions that coal washing has adverse environmental impacts. Petitioners acknowledge that in the December, 2000, newsletter of the Sierra Club in Kentucky, TGC15, the Club called for a permanent ban on coal slurry impoundments at or near underground mine works until the studies of the Martin County failure and of other impoundments is completed. TGC15. However, there are some differences between the Martin County impoundment and the TGC proposal. First, Martin County is in eastern Kentucky with its mountainous terrain, while western Kentucky has a flatter terrain. Thus, in the flatter terrain there is not the same possibility for catastrophic failure. 4-14-04 TE at 26:4-27:8 (Adams). Secondly, the Martin County impoundment was an old impoundment that was not designed with modern geotechnical methods, and it is possible to design an impoundment without the same problems. 12-1-03 TE at 118:14-24 (Fox). An impoundment does not have to be located at or near underground mine works. Moreover, there are alternatives to placing slurry from coal washing in an impoundment – it could be put in lined impoundments or underground mines, two alternatives which were not considered. 11-3-03 TE at 133:6-13 (Bhatt). Also, the slurry waste could be sold or disposed dry or even converted into energy using a CFB or IGCC. 12-10-03 TE at 182:11-15 (Tickner); P137-259 at KEC031051; 12-10-03 TE at 177:21-23 and 224:8-225:16 (Tickner); 6-14-04 TE at 109:4-17 (Adams). TGC did not evaluate these options.

437. Petitioners point to evidence that suggests that TGC decided to eliminate coal washing based on cost and then backed into a justification. 12-05-03 TE at 123:18-126:1; 129:7-24 (Tickner); P137-5 is a document entitled "List of Air Permitting Concerns", which came from TGC files. Para. 5 (d) states "Peabody needs to develop possible technical, environmental and economic restraints related to coal washing. Concentrate on the costs, so it can be eliminated as a control technology." P137-259 p. KEC31049, is an email from Peabody Vice President Jacob Williams, which indicates that the use of PRB coal, a low sulfur western coal, would be cost competitive if the project were required to use coal washing. Petitioners urge that TGC wanted to gain the Kentucky tax credit, for using Kentucky coal, as well as the savings from not using coal washing.

438. Dr. Fox opines that coal washing was not actually considered in the BACT process, as DAQ stated. Instead, she stated that it was eliminated based on a cost analysis which did not conform with the cost-effectiveness type of analysis that is required under the top-down BACT process. 11-03-03 TE at 133:14 –134:6. Dr. Fox states that it is the feasibility of coal washing per se that is the topic of a BACT analysis, and she does not think TGC can argue, given that it has other impoundments at the site, that coal washing is per se infeasible.

439. Petitioners urge that the TGC cost effectiveness analysis is erroneous for four reasons:

(1) <u>It is based only on incremental cost effectiveness</u>. The NSR Manual, Jt. #9 at B.41, and Shepherd, P160 at 133:17-134:2; 17:10-19, advise that both the incremental cost and average cost should be evaluated in order to justify elimination of a control option. Average cost effectiveness is calculated by dividing the annual cost by the tons of pollution removed. Jt. #9 at B.37. Incremental cost effectiveness is calculated by dividing the difference in annual costs

between two dominant control technologies by the difference in the emissions that they reduct. Id. at 41. In its February 2002 comments, EPA suggested that DAQ obtain or develop an estimate of total cost effectiveness (annualized dollars per ton removed) for coal washing plus FGD. EPA commented that "(a)lthough the incremental cost effectiveness may be high, the total cost effectiveness may be reasonable." P23, Comments, pg. 8, 2.d. TGC cites an incremental cost effectiveness value of $69,100 per ton, Jt. #33 at Red 46, Table 4.4.2.5-1, for which Petitioners can find no support in the exhibits cited by TGC. Petitioners point out that the figures in Table 4.4.2.5-1, Jt. #33 at Red 46, do not agree with the figures in Jt.#56, Red 46-48 ($28,111). Petitioners also point out that TGC included average cost effectiveness data, Jt. #33 at Red 46, Table 4.4.2.5-1, showing $432/ton, which was not labeled as such, and which Petitioners urge shows coal washing is cost effective.

(2) <u>It is unsupported</u>. Shepherd found the economic analysis of coal washing provided by TGC was not adequate. While the Honaker report was a good next step in the analysis, Shepherd testified that there was no justification given for the costs being presented ($69,100 per ton). P160 at 15:18-21; 17:10-19; 65:12-18; 80:24-81:8. Therefore, it was difficult to determine how TGC arrived at its calculations.

(3) <u>It contains numerous errors</u>.

a. The incremental cost effectiveness analysis assumed that coal washing would only remove 575 tons of sulfur, compared to wet FGD. 12-11-04 TE at 169:11-17 (Tickner); Jt. #41 at Red 12 (Raw versus Washed Coal Analysis). This is only one-tenth of one percent of the total amount of sulfur that enters the boiler (575/419,860), which Petitioners contend is clearly wrong. Jt. #41 at Red 12. The basis for the 575 cannot be discerned from the record.

b. The costs analysis did not include other pollutants that are removed including ash, HAPs, and additional NO_x. 6-1-04 TE at 105:15 – 107:24, 169:10-13; 6-2-04 TE at 113:17-114:1 (Fox); PR232; 1-5-04 TE at 105:15-106:13 (Tickner); PR323-1; PR232; P138-7A.

c. In addition, the analysis ignored most reduction in costs that would result from washing coal, such as improved combustion efficiency, and decrease in waste from the FGD and ESP systems. 6-1-04 TE at 105:22-106:22 (Fox).

d. TGC would not incur transportation costs for coal because it is a mine-mouth facility, which was not considered in determining whether this cost savings could be applied to the cost of coal washing. 12-5-03 TE at 126:8-127:25 (Tickner).

e. The coal washing analysis was based on a lower amount of sulfur in the coal, 7.45 lb SO_2/MMbtu, than the value used to design the wet FGD and establish the SO_2 BACT limit, 8.5 lb SO_2/MMbtu. Jt. #41 at Red 12; 1-5-04 TE at 104:20-105:4 (Tickner). This would increase cost effectiveness.

f. The coal washing analysis assumed the same SO_2 emission removal efficiency rate would be met for all options, which Petitioners urge does not take into account that coal washing increases SO_2 removal efficiency. Petitioners point out that if coal washing achieves only 35% sulfur removal, as in Dr. Honaker's report, Jt. #38, p 12, the total SO_2 removal efficiency increases from 98% to 98.7%, which would remove 1.5 times more sulfur than using just wet FGD.

g. The coal washing analysis irrationally constrains the analysis by assuming a cost per ton, Jt. #33 at Red 45 – ($5-$6/ton) that its own consultant concluded was not feasible. Jt. #38, Honaker report, p. 12.

(4) It did not demonstrate costs beyond those borne by other facilities. Dr. Honaker concluded for TGC's coal that "(b)ased on an average cleaning cost of $1.90/raw ton, total sulfur reduction up to nearly 35% can be achieved with relative small effects on the overall cost per clean ton." Jt. #38, Honaker Report, at 12. Average cost effectiveness values for conventional coal cleaning calculated in this industry study ranged from $38 to $1,700 per ton. PR 323-1, Table 4, p. 833. The average cost effectiveness to wash TGC's coal is reported as $432 per ton in Jt. #33 at 37, Table 4.4.2.5-1, and as $411 per ton in P137-12 (not submitted to DAQ). These values are well within the range borne by others. Dr. Fox reported that generally anything below $2,000 to $5,000 per ton is considered cost effective. 11-13-03 TE at 137:10-138:6.

440. Next, Petitioners urge that the adverse energy impacts TGC cites are erroneous. Petitioners point out that TGC has not documented any unusual energy impacts, and such impacts are not an adequate justification to eliminate a technology if they are within the normal range for the technology in question. Jt. #9 at B.30. While Dr. Honaker's report claimed that energy loss would be minimal, Jt. #38, p 12, TGC's BACT analysis claims energy loss of 30 to 35%. Jt. #33 at Red 43. While ignoring the increase in energy content of the washed coal, TGC addressed energy loss from coal washing by increasing plant operating costs by $40 million to mine and wash 24% more coal. Jt. #33, p. 36. Also, the coal washing cost analysis did not consider the value of waste coal, but, instead included costs for the disposal and perpetual care of coal refuse. Ms. Tickner acknowledged that Peabody sells coal refuse to at least one recovery plant in Kentucky. 12-10-03 TE at 182:11-15.

441. Finally, Petitioners point out that the benefits of coal washing, such as removing ash, trace metals and NO_x, were not evaluated even though these benefits offset many of the

alleged adverse environmental impacts. 6-1-04 TE at 105:22-107:24; 6-2-04 TE at 185:8-187:12 (Fox).

Conclusions on Coal Washing

442. DAQ states that its decision to preclude coal washing was made on the top-down BACT approach. However, since the record does not reflect that DAQ performed any analysis, this statement appears to reflect that DAQ found that TGC's evaluations of the energy, environmental, and economic impacts of coal washing were adequate and complied with the top-down BACT process. EPA and NPS, however, did not agree that TGC's evaluations were sufficient, as reflected by their comments and Shepherd's deposition, especially in the area of cost-effectiveness and in the failure to demonstrate how the impacts at the TGS facility differ from the many facilities using coal washing.

443. In response to EPA comments, TGC's response is that its cost effectiveness was performed in accord with the NSR Manual, which it maintains provides that cost effectiveness can be conducted on an average or incremental basis, citing to B.41. Although the NSR Manual provides that "cost effectiveness calculations can be conducted on an average or incremental basis", B.36, it also states that"(i)n addition to the average cost effectiveness of a control option, incremental cost effectiveness between control options should also be calculated." B.41. Thus, the NSR Manual clearly recommends that calculations of both average and incremental costs be conducted.

444. TGC states that coal washing is not a "dominant" technology when compared to the technologies selected (i.e., "the wet FGD and ESP provide greater emission control at lower annualized costs"). Thus, TGC states that it is appropriate to look at incremental cost rather than average cost per ton of SO_2 removed. Jt. #44 at Red 16-17. Contrary to TGC's assertions, the

NSR Manual does not state that incremental cost is what is used for non-dominant technologies. Instead, at B.41, the Manual states that "(i)ncremental cost-effectiveness comparisons should focus on annualized cost and emission reduction differences between dominant alternatives."

445. Shepherd clearly explained, at P160, 17:10-19, that in addition to the incremental costs he wanted to know what the total cost of coal washing would be versus the amount of emission reduction which would be achieved. "We would normally look for total cost information. Essentially what that is, is you look at the annual cost of reducing an emission versus the amount of emission that's reduced." Id. at 17:23-18:1. He said he never got the information to do that kind of total cost/benefit calculation.

446. In determining an adverse economic impact, the NSR Manual cautions that "(t)he economic impact portion of the BACT analysis should not focus on inappropriate factors or exclude pertinent factors, as the results may be misleading…. Undue focus on incremental cost effectiveness can give an impression that the cost of a control alternative is unreasonably high, when, in fact the total cost effectiveness, in terms of dollars per total ton removed, is well within the normal range of acceptable BACT costs". Jt. #9 at B.45-46. These cautions were not heeded by TGC, and indeed, it persisted in providing only incremental costs when average costs were also repeatedly requested.

447. In addition to the issue of whether TGC performed only an incremental cost analysis, or performed both an average and incremental cost analysis, however, is whether the analysis it performed is clearly supportable and understandable. Both Shepherd and Dr. Fox, the two witnesses with the most experience in reviewing BACT determinations, pointed out conclusions which were contradictory, or lacked sufficient explanation, as well as favorable

information which was not provided to DAQ. DAQ did not provide any analysis or any explanation of the cost-effectiveness TGC provided, but simply agreed with its conclusions.

448. Numerous Environmental Appeals Board cases have addressed the issue of cost effectiveness.

449. In re Masonite Corp., 5 E.A.D. 551, 566 (EAB 1994), the petitioner challenged whether the Region adequately considered the cost-effectiveness of using the existing RTO (regenerative thermal oxidizer) at the facility in combination with water-borne, low solvent coatings as BACT for the Grain Line instead of assuming an entirely new RTO would have to be built. The Board determined that the Region did not adequately explain how it determined that using the existing RTO would not be cost effective. Thus, the Board found that the rejection of the existing RTO on cost-effectiveness grounds was erroneous because it was based on an incomplete cost-effectiveness analysis.

450. In re: Pennsauken County N.J. Resource Recovery Fac., 2 E.A.D. 667, 672 (1988); 723 F. 2d 1440, the Board determined that the applicant's BACT analysis did not contain the level of detail and analysis necessary to satisfy its burden of showing that thermal de-NO_x technology is technically or economically unachievable for this source. The applicant stated that this technology was unavailable without providing a serious discussion of cost-effectiveness. Although the BACT analysis showed control costs in the range of $1,300 to 1,500 per ton of NO_x removed, and annual costs of removing NO_x using thermal de-NO_x technology, there was no discussion that showed that these costs are unusually high … by obtaining and analyzing operating data and other information from other facilities. The Board, thus, directed the agency to reopen the permit proceeding to allow the applicant to supplement its original BACT analysis.

451. In re: Steel Dynamics, 9 E.A.D. 165, 202-207 (EAB 2000), a review of IDEM's issuance of a PSD permit for construction of a new steel mill, the Board considered the issue of economic feasibility. "In general, a permit issuer will gauge economic impacts by estimating the average and incremental cost-effectiveness of various pollution control options, measured in dollars per tons of pollutant emissions removed." In response to numerous challenges to IDEM's economic analysis and underlying data, the Board states that it has been unable to find any information in the administrative record about SCR costs at other steel mills or other facilities, even though this kind of information is recommended for inclusion in a complete and thorough cost-effectiveness analysis. The Board found that IDEM's decision to reject SCR on economic infeasibility grounds was clearly erroneous because IDEM's cost-effectiveness analysis was incomplete. On remand, IDEM is directed to perform a complete analysis of SCR's cost-effectiveness, including comparisons of costs to other facilities, and submit its findings to public review.

452. I conclude that DAQ's rejection of coal washing was arbitrary and capricious because it was based on TGC's cost-effectiveness analysis which did not include average cost effectiveness and because TGC's analysis is not supportable and understandable. I, thus, recommend that the permit be remanded with directions that TGC provide a cost-effectiveness determination for coal washing that includes consideration of both average and incremental cost effectiveness.

C. Clean Coals -Using a Blend of Lower Sulfur Coal as BACT

Overview

453. Petitioners contend that the SO_2 BACT determination must be based on an analysis which considers cleaner coal. TGC and the Cabinet disagree.

Findings on Using a Blend of Lower Sulfur Coal

454. The current SO_2 BACT limit is based on worst case coal with 8.5 lb SO_2/MMbtu, although the sulfur content will be much lower most of the time.

455. Ms. Tickner explained that there will be two stock piles at the power plant, one with "somewhat lower quality sulfur coal from the 8 and 9 Seams, and then one from higher sulfur that comes from the 8 and 9 Seams…" In general, the goal is to blend the higher 8 and 9 Seam on days when the flow actually coming to[52] the plant is lower sulfur. 12-5-03 TE at 93.

456. When asked whether TGC's BACT analysis considered the option of allowing for a stock pile of lower sulfur coal to blend in order to blend out the high spots above 8.0, Ms. Tickner's response was "no". Id. at 93:19-25; 94:1. She acknowledged that Peabody owns low sulfur coal reserves and that an analysis was done of bringing in low sulfur coal to be burned for a time to make up for a high sulfur episode. Id. at 94. The analysis is found in P98-7, an Alternative Fuel Analysis memorandum by Black & Veatch, which Peabody requested examining five additional fuels for potential use in temporarily reducing SO_2 emission rates following exceedence of the permit limits. When asked whether, in light of this exhibit, Peabody looked at the possibility of burning lower sulfur fuels to reduce average emissions of SO_2, she responded, "We had a report prepared that considered it, yes." Id. at 96:1-5. However, she confirmed that use of lower sulfur coals (lower than 8.5 lbs/MMbtu) was not considered in TGC's BACT analysis. Id. at 96:6-11.

457. The Cabinet points to DAQ's response to a comment that the BACT analysis was incomplete because coal blending was not considered:

> The Division has determined that this project is designed to burn high sulfur eastern coal, and that fuel switching to the extent suggested by OBTC (Owensboro Building and Trade Council) would (be) a fundamental redefining of the source and therefore precluded by PSD regulations. OBTC is correct that the permit does not contain an upper bound on coal sulfur content, but there is an inherent requirement for a source to construct and operate as described in their application and on the same basis under which their BACT analysis was performed…. The Division does find, however, that the powerplant was designed with integral characteristics to burn Kentucky-type coal, with controls and combustion specific to this material. A plant designed to burned (sic) Western or Powder River Basin coal would be a fundamentally different design, consideration of which is precluded under the PSD rules. Jt. #63 at 14-15.

DAQ's response indicates that it was responding to a comment urging "fuel switching", not a change in the blend of the two piles being used or the use of low sulfur reserves.

Parties' Arguments on Using a Blend of Lower Sulfur Coal

Petitioners

458. Petitioners urge that DAQ never evaluated the use of cleaner coal by, for example, adjusting the blend of Seam No. 8 and Seam No. 9 coal, to achieve a lower SO_2 BACT limit. Petitioners point out that EPA has for a long time required that the permit writer examine the inherent cleanliness of the fuel. In re: Inter-Power of New York, 5 EAD 130, 134 (EAB 1994).

Cabinet

459. The Cabinet maintains that TGS is a mine mouth operation burning high sulfur coal and it lacks the authority to require TGS to burn low sulfur coal, which would be a redesigning of the plant.

TGC

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[52] Ms. Tickner at first inadvertently stated that "the goal is to blend the higher 8 and 9 Seam back on days when the flow actually coming from the plant is lower sulfur." She corrected herself and stated that she meant flow coming to the plant. 12-5-03 TE at 93:15-18.

460. TGC agrees with the Cabinet by stating that DAQ has correctly interpreted Kentucky's PSD regulations in determining that it does not have authority to require a source to change its selected fuel.

Petitioners' Reply

461. In reply, Petitioners clarify that they are not seeking to require TGS to use lower sulfur coals in place of Western Kentucky coal. Instead, they urge that TGC's SO_2 BACT analysis must include consideration of coal with a lower sulfur content than the sulfur content that TGC chose in its permit application, which could be achieved by changing the blend of the two coal piles being used, a high sulfur pile and a low sulfur pile or using low sulfur coal reserves Peabody owns. Petitioners point out that <u>In the Matter of: Old Dominion Electric Cooperative</u> , 3 E.A.D. 779, 1992 WL 92372, the Environmental Appeals Board noted that EPA construes the 1990 Amendments as conferring discretion on the permit issuer to consider clean fuels other than those proposed by the permit applicant, and in footnote 39, states that the BACT analysis should include consideration of cleaner forms of the fuel proposed by the source. Petitioners urge that Kentucky's BACT definition includes burning cleaner coal as an available method, system and technique for controlling SO_2.

Conclusion on Using a Blend of Lower Sulfur Coal

462. I do not perceive Petitioners' request to be a redefinition of the source, as the Cabinet contends. Even though I concluded in the discussion of IGCC and CFB that DAQ has discretion to require a redefinition of the source, here, Petitioners seek only to require that TGC's SO_2 BACT analysis consider cleaner Western Kentucky coals which TGC has available. I agree with Petitioners that TGC's interpretation would allow it to choose its SO_2 BACT limit

by the choice of the sulfur content of the coal. This interpretation is contrary to the purpose of BACT.

463. I conclude that DAQ erred by failing to require TGC's SO_2 BACT analysis to include an evaluation of whether there are any economic, environmental or energy reasons why a lower BACT limit cannot be achieved by a blend of cleaner coals using the coal which TGS has available.

D. BACT for NO_x Emissions from PC Boilers

Overview

464. TGC ultimately chose low NO_x burners and Selected Catalytic Reduction (SCR) to control NO_x from the PC boilers. The parties agree that this technology is appropriate for controlling NO_x if a pulverized coal boiler is selected.

465. However, the parties do not agree on what the specific NO_x limit should be. The NO_x BACT limit of 0.08 lb/MMbtu is based on an SCR NO_x reduction efficiency of 55.6%. The reduction efficiency was not evaluated as part of the BACT analysis.

466. Petitioners contend that the NO_x permit limit of 0.08 lbs/MMbtu was a limit which resulted from negotiations between TGC and regulators and that many higher NO_x reduction efficiencies and lower limits were not considered.

467. The Cabinet states that this final limit was not a negotiated limit, no source in Kentucky was at the 0.07 limit at the time the TGC permit was issued, and removal/reduction efficiency is not part of the Kentucky BACT definition.

468. TGC contends that while Petitioners have identified information which they believe should have been considered, they fail to show that this information would have led to a different result. TGC maintains that DAQ had a reasoned basis for its NO_x BACT determination.

Findings - BACT for NO_x

469. With regard to the control technology chosen, low NO_x burners minimize the NO_x levels out of the boilers by lowering the combustion temperatures. The SCR is essentially a big metal frame in the exhaust duct with panes like in a window. Ammonia is injected into the duct and the ammonia combines with the NO_x and reacts in the presence of the catalyst to chemically form nitrogen gas and water. SCR systems, which is a technology which has been in use since

the 1980s, are capable of achieving a wide range of levels of NO_x removal, from 50% up to 93% depending on how the system is designed.

470. With regard to NO_x limits, the permit sets a NO_x BACT limit of 0.08 lb/MMbtu based on a 30-day rolling average. Jt. #8, p.3, Sec. B(2)(f). TGC's 30-day averaging period tends to smooth out or average the peaks and high values.

471. The degree of NO_x reduction on which the BACT limit was based was not disclosed during the permitting process. In fact, the degree of NO_x reduction for the SCR (55.6%) was only discovered in the ALSTOM proposal in confidential documents produced in August 2003, almost a year after the permit was issued. Thus, the range of control (or reduction) efficiencies were not evaluated in the BACT analysis. 12-5-03 TE at 123:8-10 (Tickner). In other words, a listing of specific emission limits proposed for this project and the corresponding "degree of reduction" for each was not provided. This is typically included in a BACT analysis and is required by Step 3 of the NSR Manual. Instead, the record only lists "emission rates per unit of heat input" and does not list "the maximum degree of reduction for each pollutant". The higher the degree of reduction, the lower the emission limit.

472. In the NO_x BACT review in the SOB, Jt. #7, p. 20, the technology is listed and DAQ states that the NO_x emission limit is based on the RBLC. There is no explanation why lower NO_x limits were not selected as BACT. Justification for the NO_x limit achievable by SCR is found in Jt. #17 at Red 107-108, in TGC's responses to comments provided on September 16, 2002, after the public comment period. TGC states that the level of control by the SCR is equal to or better than those of similar units.

> While NO_x limits lower than the proposed 0.08 lb-NO_x/MMbtu are proposed, no units firing similar fuel and of similar design and operation to those proposed at TGS are currently achieving the lower limits on a continuous basis…. Based on

> information obtained from various permitting authorities throughout the United States and recently proposed or permitted coal fired electric utility generating stations, an emission limit of 0.08 lbs/MMbtu based on low NO_x burners in combination with selective catalytic reduction (SCR) is demonstrated BACT for PC boilers. Each of the facilities cited by the commenter is fundamentally different from TGS. Most notably, most are retrofit units for which NO_x limits apply only a few months a year. That factor greatly affects the catalyst life and the economics. Id.

473. Tickner acknowledged that a cost analysis was not submitted for achieving greater levels of NO_x reduction. 12-10-03 TE at 163:13-16.

Expert opinions on BACT for NO_x[53]

Dr. Phyllis Fox

474. PD153-6[54], NO_x Removal, is a demonstrative exhibit Dr. Fox prepared which summarizes various design basis NO_x removal efficiencies. The Y-axis is the vendor design basis NO_x removal percent, and the X-axis is the name of the facility. The percent sulfur in the coal is shown above some of the bars. This exhibit compares the NO_x reduction efficiency of TGC with 29 coal-fired boilers that range from 70% to over 90% and supports Dr. Fox's opinion that the level of NO_x removal proposed for TGC does not represent BACT. Dr. Fox stated that there have been hundreds of SCR systems guaranteed for NO_x removal efficiencies that are quite a bit higher than the 55.6% that the NO_x BACT level of 0.08 represents for this facility. In her opinion, TGC's BACT analysis clearly did not choose the most effective level of control that had been achieved by SCR technology for NO_x. When the most effective level of reduction or removal of a pollutant is not chosen, Dr. Fox would expect to find an explanation for why the

[53] Facts supporting the experts' opinions are included in their testimony.
[54] The evidence supporting each bar on PD153-6 was presented on 11-6-03 TE at 126-153 and 11-12-03 TE at 38-99.

most effective level was not chosen based on chemical and physical characteristics of the flue gas and engineering design criteria.

475. In providing foundation for each of the entries on P153-6, Fox offered P73, ALSTOM Power's SCR Experience List which is a chart with a list of facilities for which ALSTOM has provided SCR systems listing the customer, fuel, name of the plant, size of the plant, NO_x removal efficiency, etc. This is the type of information the NSR Manual refers to as being relevant for a BACT analysis. Many facilities are listed with NOx removal greater than 56%.

476. From her review of the record, Dr. Fox saw that TGC's NO_x limit of 0.08 lbs/MMbtu was a negotiated level, negotiated between Peabody and the agencies, and it was placed in Black & Veatch's bid specification package as a given. P68A is the Black & Veatch bid package which went to vendors. This is what the vendors bid on, and what became the permit limit. She saw no evidence that vendors were ever asked the question "How low can you go?" She found no substantial evidence that an effort was made to determine the lowest achievable emission limits. In sum, Dr. Fox testified that all of the permit limits were specified in a bid package, as opposed to originating from a top-down BACT analysis. P68A.

477. In fact, Burns and McDonnell, one of TGC's partners on this project, prepared the Cash Creek application with a higher NO_x removal efficiency. P137-106, Table 5-4 and p. 5-9; 11-12-03 TE at 79:5-80:5; 6-1-04 TE at 57:22-58:3. In documents produced during discovery, another partner, ALSTOM, the pollution control vendor, identified a high-sulfur, high-ash coal where it was proposing a 90% removal efficiency, i.e. Paradise, Homer City Unit 3. P73.

478. With regard to how TGC's coal quality affects the NO_x BACT analysis, Dr. Fox states that there are a number of constituents in coal that can affect the design of an SCR system,

such as sulfur content, ash content and various chemical constituents, like arsenic. Thus, these parameters are considered in the design of the SCR system and are normally dealt with in a BACT analysis or the cost-effectiveness analysis. The parameters are not used as a basis to screen out technologies. Here, TGC failed to evaluate experience with coals other than western Kentucky's Seams 8 and 9 rather than evaluating them through a top-down BACT process and including design basis in the cost-effectiveness analysis.

479. When asked how much investigation is enough for a top-down BACT analysis, Dr. Fox responded that enough data should be collected to be confident that the lowest emission limits that can be achieved have been identified and by being comprehensive on the sources checked. Dr. Fox says it took her about two days to determine that there were lower candidate NO_x BACT emission limits that had not been considered by TGC.

480. Over much objection, Dr. Fox was asked what she would conclude is more likely than not to result from a proper BACT analysis for NO_x. Considering only permit limits that were available before the TGC permit was issued, the highest would be 0.07 lbs/MMbtu. 12-4-03 TE at 72:11-21. The NO_x BACT level proposed for TGC is at the upper end of the range of the NO_x levels achieved by commercial SCRs. P137-53, p. 32, Fig. 1-12; 12-3-03 TE at 120:14-122:24 (Fox). It should have been at the lower end of the emission range. Id. at 122:10-13.

481. P153-5, entitled Candidate NO_x BACT Limits[55], is a bar graph prepared by Dr. Fox showing the investigations

[55] Beginning from the left side of P153-5, or lowest NO_x emission limit, and going to the right are the following in lbs. NO_x/MMBtu.

.015 - Baldwin, the facility Matt Haber's report relates to regarding the BACT NO_x limit. The Haber Report, P119-2, was prepared by Matt Haber, one of EPA's primary BACT experts, who is located in Region IX. The report is dated April, 2002, and was prepared in litigation between the US and Illinois Power Company regarding modifications that were made at the Baldwin facility without properly securing a permit under the PSD program. Dr. Fox received the report by telephoning Mr. Haber in May, 2002, and asking if he had made any

BACT determinations on coal-fired power plants. Page 50 of the Haber report shows that with the use of SCR, unit 3 can reach an emission level of .015 MMbtu (which is the lowest emission limit listed and the latest in time). (P123-77 is the Supplemental and Rebuttal Report by Matt Haber – October 2002).

.016 – Thoroughbred Ultra Low Emission Project, a proposal (referred to as TULEP) to the US Department of Energy by Babcock and Wilcox and McDermott Technologies, dated April, 2001, for funding to demonstrate on the subject TGC facility an ultra low emission train on one of the two 750 MW PC boilers. P137-53. This specific sequence of pollution control technologies are identified in a Babcock and Wilcox paper called "How Low Can You Go" that in combination are able to achieve much lower emission limits for most all of the pollutants under contention in this case than the limits that are present in TGC's permit. The NO_x limit in the Ultra Low project is .016 lb/MMbtu, which is one-fifth of the limit proposed by TGC as BACT. The TULEP proposal, P137-53 at p. 6, shows that "(a)t least 90% mercury removal will be achieved…."

.016 - Babcock and Wilcox paper entitled "How Low Can We Go", describes a series of pollution control technologies to achieve lower emission limits. The paper examines emission control technologies for eastern bituminous high sulfur fuels, similar to the fuel TGC plans to burn. Dr. Fox pointed out that the state of Georgia rejected an application for a coal fired power plant because it failed to evaluate the emission limits in this paper and concluded that BACT was established by this paper. (P120-7). On cross-examination, TGC pointed out that in TGC-109 it shows that Babcock and Wilcox in June 2002 declined to guarantee 90% mercury removal for WE Energy (Wisconsin Electric) Elm Road facility, even though in August, 2001, Babcock and Wilcox published its paper "How Low Can We Go" saying that mercury could be possible at 90% removal efficiency. Dr. Fox points out that a technology does not have to be demonstrated in practice to be a candidate technology in the top-down analysis.

.036– Amager – a coal fired power plant in Copenhagen, Denmark, which is achieving .036, as reflected by the CEMS data. Dr. Fox discovered this information from catalyst vendors in June or July, 2001.

.03 – Parish, Unit 5, based on the vendor guarantee and subsequent performance test. The Texas Resource and National relied on this level in establishing a LAER limit for coal-fired power plants in nonattainment areas in TX.

.032 - Trimble – vendor guarantee level which was verified in vendor performance tests, which are based on short term tests.

.033 - SIP Dallas/Ft. Worth – Texas Register dated October 12, 2001, determination for the Dallas/Fort Worth nonattainment area. (P28).

.037 - Sweden – basis was 1996 EPA report on European SCR experience. (P161).

.04 – SIP Houston/Galveston determination also reported in Texas Register, October 12, 2001 (P28).

.04 - Boswell – Information based on a study conducted between February 2001 and December 2001, posted several months thereafter on the website.

.04 – Montour, with a reduction of NO_x of 90%, corresponds to 1,000 tons per year, compared to the emissions from TGC, which are in excess of 5,000 tons per year. (See P153-7).

.04 - Harrison, an Allegheny coal-fired power plant in WV, burning high sulfur eastern bituminous coal. (PAR123-178). Dr. Fox testifies that vendor guarantees in conjunction with a short-term performance test is sufficient based on the guidance in the NSR Manual.

.04 - Pleasant Station – the basis for this bar is the vendor guarantee and successful completion of the performance test. (PAR137-354).

.04 - Japan 250MW – based on paper presented at EPA 1995 Joint Symposium. Facility is designed to achieve 80% NO_x removal efficiency and outlet NO_x level can be converted to same units TGC uses, which is roughly .04 lbs/MMbtu.

.042 - Cayuga has a required NO_x reduction of 90%. (P120-18; P123-158).

.05 - Cash Creek – PSD permit application for the Louisville, KY, plant, contains DAQ date stamp of September 14, 2001. P137-106. The Cash Creek permit application is included in TGC's Addendums submitted in May 2002 (Jt. #33, Table 4.2-1). Burns and McDonnell, TGC's own contractor, has proposed a NO_x limit of .05 in the Cash Creek permit application with a 90% NO_x reduction limit. However, there was no top-down BACT analysis in the TGC permitting process that included that limit, no demonstration of technical infeasibility, no demonstration that that limit would not be cost effective, and no demonstration that that limit had unacceptable she did to determine whether there were any lower NO_x emission limits that should have been considered in the TGC BACT analysis. Each of the technologies represented in the chart was available and demonstrated at the time of the TGC permit and, in her opinion, should have been included in a top-down BACT analysis. PD153-5 is based on a 30-day rolling average time. TGC's NO_x emission limit of 0.08 MMbtu is shown on the right side of the chart with some 20 lower NO_x emission limits to the left of TGC. Those with lower NO_x emission limits, ranging from 0.016 to 0.07, represent permit applications, permits, test data, vendor guarantee information, BACT determinations by other agencies, published literature and proposals by vendors. Dr. Fox stated that these documents are the kind of information that is normally relied upon by environmental engineers in the course of preparing air permits or air permit applications.

482. Dr. Fox was not able to find in TGC's submittals all the information relevant to determining the NO_x BACT limit. Most notably, she could not find the boiler outlet NO_x, which in this case was the SCR inlet NO_x level, which is one of the factors that is needed in order to determine what the NO_x concentration is coming out of the SCR system. The ALSTOM boiler is designed to achieve an outlet NO_x level of .18 pounds per MMbtu (this is .18 to enter the SCR). TGC42, a diagram of the pollution control train, shows that the low NO_x burners are the burners inside the boiler. The SCR is after the boiler. For doing a BACT determination, it is important to know what the inlet to the SCR NO_x level is.

483. Six of the bars in Dr. Fox's bar graph, PD153-5, are included in TGC's production of documents. In Dr. Fox's opinion, the list in Table 4.2-1 which TGC submitted

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energy or environmental impacts. TGC noted on Table 4.2-1 that Cash Creek had a "similar boiler design and fuel use" and also noted "no permit yet/not demonstrated".

with its Addendums, Jt. #33, still falls far short of being an adequate comparison because there were many other facilities that TGC did not identify and Dr. Fox found in her research. Also, all of the facilities TGC did identify with lower emission limits were excluded and did not go through a formal top-down BACT analysis.

484. One of the first things Dr. Fox does when doing a BACT analysis is to get from catalyst vendors their experience lists which will show the lowest units they have provided. Over the life of the catalyst, the activity decreases due to interactions between chemicals in the gas stream and the active agents in the catalyst. Thus, a fresh catalyst will achieve a higher NO_x reduction efficiency at the beginning of its life than at the end of its life. However, when a vendor issues a guarantee on a catalyst, the guarantee is at the end of the life of the catalyst. Most catalysts are guaranteed for three years. If a guarantee is 90%, the 90% applies at the end of the three-year period.

485. Dr. Fox was asked if she is aware of any permits anywhere at any time with lower NO_x limits for PC boilers. She responded by listing the Round-up permit with a preliminary determination of 0.07, two Georgia power plants (Bowen and Wonsley) and WYGEN 2.

486. PD153-7, NO_x Emissions vs. NO_x% Removal**,** is a demonstrative exhibit Dr. Fox prepared showing NO_x emissions vs NO_x% removal, with tons per year on the y-axis and percent removal on the x-axis. TGC's permit limit of .08 pounds per MMbtu corresponds to an SCR control efficiency of 56%. The four blue bars to the right of TGC's permit limit represent different levels of NO_x control that have been achieved in practice on other facilities. These different levels are 67%, 80%, 90% and 95%. If that limit is multiplied by the heat rate, which is

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.05 - Somerset – The outlet NO_x of .05 corresponds to a 90% NO_x reduction. P120-19. This plant burns a high sulfur coal. The SCR exceeded expectations. (P120-19, P120-20, P120-21 and P120-22).

7,443 million Btus an hour, and converted into tons, the result is the number shown on the TGC/purple bar, which is a little in excess of 5,000 tons per year, which is based on 56% NO_x control.

487. Had the SCR system at TGC been designed to achieve 80% NO_x control (SCR systems have operated at 80% NO_x control since the ‘80s in Europe and Japan), the emissions would have dropped more than in half. Had the SCR system been specified for 90% control, as many SCR systems have been, including many by ALSTOM, which is the vendor of TGC’s pollution control system, the NO_x emissions would drop by more than a factor of five. Had the SCR system been specified for 95% control that Dr. Fox has seen for SCR systems, TGC’s NO_x emissions would have dropped to about 500 tons per year.

Shepherd on BACT for NO_x

488. Shepherd stated that NPS had seen several permits issued or applications proposed at a NO_x emission limit of 0.07 lbs/MMbtu. P160 at 18. These included Black Hills Power-Wygen 2; Santee Cooper Cross 3 and 4; Bull Mountain-Roundup; Intermountain Power Project, Unit 3 (a CFB project), AES Warrior Run and Kentucky Western Power (withdrawn). Id. at 26. He was of the opinion that the TGC NO_x limit “could be a little bit lower, down to 0.07.” Id. at 101.

Powers on BACT for NO_x

489. Powers agrees with Dr. Fox that an SCR vendor could have provided a higher efficiency NO_x reduction (than 55.6%), if requested. He opined that a 90% reduction of NO_x is achievable with SCR for coal-fired power plants. The facilities he is aware of that have NO_x guarantees lower than TGC are Trimble County, which is guaranteed at 0.032 pounds per MMbtu; Harrison Station and Pleasant Station power plants in WV, guaranteed at 0.04. Also, in

conversations with Haldor Topsoe, the firm which provided the 0.04 MMbtu limits, Powers was told that Haldor Topsoe had experience on Kentucky No. 8 and 9 coal and did not foresee a problem with those coals with use of an SCR. 11-10-03 TE at 118 (Powers). He also talked with Hitachi America about the Trimble County plant, which it guaranteed at 0.032 lbs/MMbtu and guaranteed at 90% reduction with a low NO_x burner, which is the basis for stating that 90% reduction with SCR following a low NO_x burner is not only feasible, but has actually been guaranteed and is in operation. Id. at 122. With regard to how vendor guarantees are different from vendor puffery, Powers said that once a contract is signed, the vendor is contractually obligated to meet the guarantee. Thus, the puffery ends at the point that a contract is signed. He also disagrees that vendor guarantees have to be set higher than the guarantee in order to establish continuous compliance. Instead, the vendor builds a cushion into the guarantee.

Lillestolen

490. Lillestolen stated that in October 2002 there was no commercially available technology which could achieve a lower NO_x emission limit using the type of fuel TGS will use. 3-17-04 TE at 66. He stated that there are legitimate technical reasons for the design provided by ALSTOM. He explained that the characteristics of the coal, such as the sulfur and ash content, affect the operation of the SCR. 3-16 and 3-17-04 TE. The sulfur content of the coal has a bearing on the quantity of catalyst used, with the SCR converting NO_x to nitrogen and oxygen and also converting SO_2 to SO_3 resulting in the formation of sulfuric acid (H_2SO_4). Lillestolen said this is an example of the multi-pollutant interaction which must be addressed as part of the BACT analysis. By adding more ammonia to the SCR in an attempt to reduce NO_x emissions, this also causes problems with high-sulfur coals, such as fouling and clogging of the preheater located downstream of the SCR. Popcorn ash, which is large particulate matter, can also result from high ash, high sulfur coals, which can block the SCR.

Parties' Arguments on BACT for NO_x

Petitioners

491. Petitioners contend that TGC's 0.08 lbs/MMbtu NO_x limit does not represent BACT, but instead was the result of negotiations between regulators, and ignores overwhelming evidence that a lower limit should be BACT. Petitioners point out that TGC's revised BACT Table 4.2-1, in Jt. #33 at Red 21, includes three PC boilers with NO_x emission limits lower than TGC's. One of these was the Cash Creek application, at 0.05 lbs/MMbtu, which TGC notes had similar boiler design and fuel use, but was apparently eliminated because the facility was not yet permitted/not demonstrated. TGC's engineer, Burns and McDonnell, was also used by Cash

Creek. Petitioners point to other facilities with lower limits which are included in Dr. Fox's demonstrative exhibits.

492. Petitioners urge that TGC was well aware of the improvements in NO_x control, as seen in P37, a document from TGC's files entitled "Latest SCR Technologies and Experience on Coal-Fired Boilers". Although TGC rebuffed the viability of NO_x emission limits at coal fired power plants being retrofitted with SCR to comply with the NO_x SIP call, EPA stated that plants being retrofitted with SCR to comply with the NO_x SIP call could be considered in the BACT analysis, as could projects in other countries. Jt. #44 at Red 12-13. Petitioners point to PRD341-1, a rebuttal document showing nine units designed and guaranteed before TGC's permit was issued, operating for the whole ozone season below 0.07 lb/MMbtu.

493. With regard to the removal efficiency, Petitioners note that in its application TGC acknowledged that the control efficiency of SCRs is from a minimum of 60% up to 90%. Shepherd stated that the NPS had seen NO_x removal efficiencies as high as 90% for coal fired boilers. P160 at 19. In a 1996 study an EPA researcher found SCR NO_x removal efficiency in coal fired units ranging from 54 to 94%, with the efficiency depending on the NO_x reductions the plant wants to achieve. P161 at 12/17. In response to TGC's argument that its NO_x removal efficiency is low because its inlet NO_x level is low, Petitioners point to PR 301 at p 6, an ALSTOM paper showing Eastern Kentucky Power Cooperative's Spurlock plant achieved 82% for one unit and 83% for another with low inlet NO_x. In response to TGC's claim that a high removal efficiency is not possible on its high sulfur coal, Petitioners point to a Babcock & Wilcox paper explaining that a 95% removal efficiency is achievable on high sulfur eastern bituminous coal. P25 at 1. Petitioners also note that none of the SCRs on ALSTOM's experience list for coal are at less than 70% removal efficiency. P73.

494. TGC contends that the 0.08 lbs/MMbtu on a 30-day rolling average is the lowest rate achievable continuously under worst-case conditions for the life of the plant. Id. at 107-108. TGC points out that this NO_x limit will apply at all times, including startup, shutdown and malfunction.

495. TGC's design expert, Lillestolen, explained significant constraints which are imposed by the characteristics of TGC's fuel, such as the high sulfur and high ash content. 3-16-04 TE. Lillestolen enumerated a number of problems (such as ammonia slip and popcorn ash) which constrain the designer of the SCR. Id.

496. TGC cites to other permits issued in the same time frame as the TGC permit, with which its NO_x limit is consistent. 4-12-04 TE at 87-88 (Adams); CabR 28; CabR30, PR235, P120-53, TGCR224, TGCR225 and TGCR229. Although TGC notes that a few permits were issued in late 2002 with NO_x limits of 0.07 lbs/MMbtu, it urges that this does not mean that DAQ's determination was arbitrary and capricious. Moreover, TGC urges that it is appropriate for its BACT limit to include a safety factor. 4-14-04 TE at 197-99 (Adams).

497. TGC maintains that a 90% SCR removal efficiency is not BACT. TGC points out that Dr. Fox's testimony in this regard is based on retrofit units on which it is easier to achieve lower emissions based on their operating experience and knowing how the equipment will operate. 4-13-04 TE at 37-38, 95 (Adams). In addition, it points out that most of these retrofit facilities are attempting to lower their NO_x emissions in response to the NO_x SIP call, which went into effect in May 2004, and requires a group of facilities in certain states to reduce their combined NO_x emissions by a specified amount. 2-19-04 TE at 144-45 (Andrews). If a certain plant cannot meet its "quota" of NO_x reductions, it can buy NO_x credits from other facilities that

have emissions below their allotment. Thus, no single plant is required to meet a designated NO_x target continuously. 4-13-04 TE at 41-42 (Adams). Also, a retrofit facility is required to meet its NO_x target only during the five months of ozone season, not year-round. Id. at 44-45.

498. TGC maintains that the evidence offered by Petitioners (from CEMS data, short-term stack tests or vendor information) does not support a lower limit. TGC points out that a single season of CEMS data only shows the emission rates when the catalyst is relatively new. Indeed, TGC states that the CEMS data available to DAQ prior to issuance of TGC's permit indicates that the retrofit facilities were not achieving significantly less than 0.08 on a 30-day rolling average. TGC201; TGCD153-012; TGCD153-013, TGCR340, TGC219, PR230-8, PD153-16. The 2001 and 2002 CEMS data supports the NO_x limit in TGC's permit. 4-13-04 TE at 88-89 (Adams).

499. TGC asserts that Petitioners' reliance on stack test or performance test data to assert lower NO_x limits are achievable does not demonstrate what is achievable over the life of the facility because such data provides only short-term results. Id. at 91-92. Actual operating experience shows these facilities are not continuously achieving the levels claimed by Petitioners. TGC201, TGCD153-012, TGCD153-013, TGCR340, TGC219; 6-2-04 TE at 181 (Fox); 4-13-04 TE at 85-87 (Adams); PRD 230-8; PD 153-16.

500. Because proposals to the Department of Energy (DOE) are for technologies that are not demonstrated in practice, TGC contends that it was not required to consider these proposals. 4-13-04 TE at 122 (Adams).

501. At p. 178-182 of its post hearing brief, TGC provides a chart identifying facilities cited by Petitioners and indicating for each why TGC believes a lower emission rate for NO_x to satisfy BACT is not compelled, based on the following factors:

*Different fuel
*Retrofit
*Cap/trade no permit limit
*Short-term test data only
*Limited data/ozone only
*Pre-permit CEMS data does not support lower limit
*Vendor promotion or design only

502. TGC urges that the Cash Creek application, P137-106, with a 0.05 lb/MMbtu NO_x limit does not mandate a lower NO_x limit for TGS because the application was deemed incomplete by DAQ and was withdrawn by the applicant. Thus, DAQ did not rely on the Cash Creek application in the TGC BACT review. 4-13-04 TE at 71-72 (Adams). Id. Adams described the application as "speculation from Burns & McDonnell on a tentative project." 4-22-04 TE at 163 (Adams).

Cabinet

503. The Cabinet briefly points out that no source in Kentucky was at a NO_x emission limit of 0.07 at the time of the TGC permit. 4-12-04 TE at 89:20-24 (Adams). Wyoming's Black Hills (P120-034, WYGEN 2) is a smaller operation using Western coal, which was issued with a limit of 0.07 several weeks before the TGC permit. This would not have made a substantive difference in the TGC permit. 4-13-04 TE at 21:8; 27-29 (Adams). Georgia Power's Bowen plant was issued a limit of 0.07 for a retrofit based on the ozone season. Adams' compiled several pages of his notes and comments regarding the facilities cited by Dr. Fox. CabD21.

Petitioners' Reply

504. In reply**,** Petitioners urge that there were many higher NO_x reduction facilities and lower limits that were not considered.

505. Petitioners maintain that the NO_x BACT limit was not based on a reasoned analysis because the maximum degree of NO_x reduction was not disclosed or considered in the BACT analysis, although Kentucky's BACT definition states that BACT "means an emission limit … based on the maximum degree of reduction for each pollutant". Petitioners point out that DAQ now is requiring a listing of specific emission limits proposed for a project and the corresponding "degree of reduction" for each from permit applicants as required by Step 3 of the NSR Manual. PR237, p. 3, items 8 and 11 and table B-1; PR324, p. 2, item 3.

506. In addition, Petitioners maintain that the NO_x BACT limit was not based on a reasoned analysis because the technical feasibility of meeting a lower NO_x limit was not documented in the permitting record.

507. Next, Petitioners point to evidence which demonstrates that TGC's coal quality is not a design constraint but instead is a design parameter for which other engineering firms, catalyst vendors, consultants and plant operators have identified SCR design solutions. PR261; PR339; P213; P214; TGC203. This was confirmed by Powers, an engineer with design experience, who polled SCR vendors on available NO_x emission guarantees for TGS's coal. 11-10-03 TE at 118:13-21; 125:21-24; 118:4-8. In a 1997 report by EPA on the performance of SCR on coal-fired boilers, EPA indicates that proper design can mitigate mechanical and chemical impacts on the catalyst. P178 at 32. Moreover, Petitioners note that although TGC's sulfur content and ash content are high, they are well within the range of sulfur contents of bituminous coals used by the existing fleet of power plants.

508. Petitioners point out specific SCR design solutions for the coal quality problems TGC cites. The solutions include 1) use of a catalyst with a low SO_2 oxidation rate and high resistance to fly ash erosion; 2) use of an edge-hardened catalyst surface coating to minimize

deactivation by fly ash; 3) soot blowing to prevent fly ash accumulation on the caralyst surface; 4) periodically raising the catalyst temperature to reverse any SO_3 impacts, etc., as demonstrated by design engineering firms and catalyst vendors. PR261, P120-041, P213, P214 and TGC203. Petitioners also discuss the design solutions to the creation of sulfuric acid mist and point out that this is the type of issue that should have been addressed in the BACT analysis, as with ammonia slip (PR334, p 53, PR325, p 4, Eq. 4 and p 4) and popcorn ash (P163, p 20-21; PR261, p 18-19).

509. Ironically, TGC's BACT analysis did not address the impact of coal quality on the achievable NO_x limit. Only after the close of public comment did TGC include the response that there are "no units firing similar fuel", without any further explanations. Jt. #17 at Red 108.

510. Petitioners respond to TGC's statement in its post hearing brief, at p. 172, that the combined technology of low NO_x burners and SCR remove roughly 88% of the NO_x. Petitioners point out that because the record does not contain the uncontrolled NO_x level, which is required to calculate the total NO_x control efficiency, there is no basis for TGC's conclusion.

511. Petitioners urge that the record is replete with evidence that a higher NO_x reduction efficiency than 55.6% is achievable for TGC as shown by PD153-6, NO_x Removal, Dr. Fox's exhibit summarizing various design basis NO_x removal efficiencies. Also, on rebuttal, Petitioners adduced evidence comparing TGC's NO_x reduction with that of 53 coal fired boilers equipped with SCR systems designed, guaranteed, and/or operating at 85% to 90% NO_x control before the TGC permit was issued. PR341-2. Dr. Fox, on rebuttal, cited other plants permitted or operating with greater than 55.6% NO_x reduction, including Spurlock (82 to 83%), Homer City (90%),Enel Produzione Spa (80%) and Allegheny's Pleasants and Harrison Stations (95%), 6-1-04 TE at 93-94. The two charts prepared by Shepherd and attached to his deposition, P160-2

and P160-3, show three facilities permitted prior to TGC with higher NO_x efficiencies, Wygen 2 – 85%, Roundup – 80% and Santee Cooper Cross – 90%.

Petitioners urge that lower limits are achievable

512. TGC's document production included a summary of NO_x emission limits for the third quarter of 2002, which listed several facilities that had achieved NO_x emissions limits lower than 0.08 lb/MMbtu – two units at the Ray D. Nixon facility in Colorado that achieved 0.038 and 0.042 lb/MMbtu, the Mountainview facility in WV achieving 0.04 lb/MMbtu, the High Wagner facility in MD achieving 0.07 lb/MMbtu and the Spurlock facility in KY achieving 0.07 lb/MMbtu. P137-157. The ALSTOM SCR experience list indicates that ALSTOM had guaranteed SCR systems at 90% control on high sulfur coals (Paradise, Homer City Unit 3), compared to TGC's at 55.6%. P73.

513. Petitioners cite to multiple exhibits which show that lower NO_x limits are achievable:

* An EPA report dated 1997 showing one coal-fired plant operated at 0.04 during variable load and at 0.07 during maximum load. P161, handwritten p. 7.

* CEMS data available before TGC's permit was issued shows that Plant Bowen in GA achieved a lower NO_x limit than 0.08 lb/MMbtu before October 2002. TGC 219, 720 hour plot, BOWN2ALL to QTR2 02. Also, Mountaineer CEMS data was available prior to October 2002. P137-258, PR230-8.

* CEMS data for some SCR units on PR 341-2 designed and/or started up prior to October 2002 demonstrate these higher NO_x efficiencies allowed these plants to achieve lower NO_x limits than proposed for TGC, ranging from 0.052 to 0.069 lb/MMbtu. PRD 341-1. Petitioners' response to TGC's objection of this evidence (because it postdates the permit) is that TGC also objects to vendor data and technical literature (although it predates the permit), and the post permit CEMS data shows that the vendor and technical information was reliable.[56]

* Dr. Fox's bar graph, PD153-5, compares TGC's 0.08 NO_x limit with other similar coal-fired boilers, ranging from 0.015 lb/MMbtu to 0.07 lb/MMbtu.

[56] Petitioners urge that it would be unfair if they are limited to the strict rebuttal standard observed in the hearing for post-permit documentation (i.e., post permit evidence was not allowed in Petitioners' case in chief because TGC had the benefit of an October 2002 BACT date), but TGC and the Cabinet are permitted to rely on post hoc rationalizations and post permit evidence to support the determination.

* A Peabody document reported NO_x emissions from “commercial SCR’s” range from 0.03 to 0.093 lb/MMbtu. P137-53, p. 32, Fig. 1-12; 12-3-03 TE at 120:12-122:24.

Petitioners’ response to relevance of information

514. Petitioners respond as follows to TGC’s contention that many of the types of information they cite for support are not relevant:

PRB Limits

515. While TGC suggests that lower NO_x BACT determinations for PRB coals are not relevant because it is easier to meet a lower NO_x limit using PRB coals, Dr. Fox explained that PRB coals present SCR design problems and SCR vendors prefer to design for a high sulfur, high ash coal like TGS’s. 6-1-04 TE at 169:21-170:13.

Retrofit experience

516. A retrofit unit is an existing unit that is modified after it has been constructed to include an SCR. For a new unit, on the other hand, the SCR is designed and constructed at the same time as the boiler and pollution control train, allowing the total system to be optimized.

517. EPA Region 4 stated, in a letter to DAQ dated February 26, 2002, that retrofit experience was specifically relevant to TGS. In the letter, EPA Region 4 listed examples of the types of information and reference sources which should be consulted prior to issuance of the TGC permit, and included retrofits among the examples listed, by stating:

> a. The nitrogen oxides (NO_x) control levels achieved (or expected to be achieved) at the many existing coal-fired power plants that have installed (or are planning to install) selective catalytic reduction (SCR) controls for NO_x SIP call purposes or other purposes. Jt. #44 at Red 12.

Petitioners also cite to the opinions of Powers, Lillestolen, Haber, Fox and Chicanowicz on retrofits. Powers stated that there is not a great deal of difference between a retrofit plant and a new plant meeting low NO_x limits. 11-10-03 TE at 184:3-13. When asked whether a retrofit SCR would be expected to perform better than an SCR on a new facility, Lillestolen responded that it depends on what the customer asks for. Thus, he did not confirm TGC's position that lower NO_x limits are easier for a retrofit. 3-17-04 TE at 32:12-33:16. Haber, a BACT expert in Region 9 (P119-002, p. 3-4), prepared a BACT analysis for the Baldwin facility in Illinois in April, 2002. Because he concluded that it was *more* difficult for a retrofit unit to meet a low NO_x limit, he increased his BACT determination from 0.015 lb/MMbtu to 0.02 lb/MMbtu to adjust for Baldwin Unit 3 being an existing unit. Id. at 50. Dr. Fox explained why a retrofit can represent a worst-case design situation for SCR and why a new plant is relatively easy to design for and should be able to meet better limits than a retrofit. 12-3-03 TE at 157:21-159:7. Chicanowicz, TGC's witness, in a white paper prepared for industry associations, drew similar conclusions. P123-13A, p. 8.

518. TGC claims that CEMS operating data for retrofit units is not relevant because they only operate five months of the year, during the ozone season and are not required to meet any specific permit limits. However, Petitioners point out that CEMS data is relied on by reasonably prudent environmental engineers. The EPA technical report to support the NO_x New Source Performance Standards relied on 90 days of CEMS data for each of two units to set a national NO_x standard that applies to all steam electric generating units >250,000 MMbtu/hr fired on all coals. P224, Sec. 3.6.2.4, p 3-177, et seq. Dr. Fox stated that the ozone season experience represents a worst case compared to a new plant operating SCR on a continuous basis. 12-2-03 TE at 156:13-157:15.

519. TGC claims that a single season of CEMS data shows only what emission rates are possible when the catalyst is relatively new, thus arguing that this does not indicate what

emissions are achievable over the life of the facility. However, Petitioners point out that an SCR catalyst is designed for the end of the catalyst life, with uniform performance over the life of the catalyst. P120-18, p. 3. Petitioners note that some of the CEMS data presented are not from a single season when the catalyst is relatively new, i.e. data for two years for Bowen Unit 2 and Mountaineer show no degradation in performance with NO_x limits lower than 0.08 lb/MMbtu. Some of this CEMS data was available before the final permit was issued.

520. Next, Petitioners urge that TGC injected the margin of safety issue to offset an unfavorable record. However, Petitioners point out that a safety factor is encompassed in the 30 day average because it allows TGC to average out peaks or exceedances. 6-2-04 TE at 129:25-130:12 (Fox); P23, Comments, p. 9. Although TGC cites Masonite, supra, as authority for including a margin of safety, Petitioners point out that the Board in Masonite set out certain limited conditions under which an agency has discretion to base an emission limitation on a control efficiency lower than the optimal level. However, none of these conditions apply to TGC or are documented in TGC's permit record. Masonite at 560-561. Petitioners also point out that SCR has been applied to hundreds of coal-fired boilers, many burning high sulfur fuels, and NO_x control efficiency can be maintained at a constant level by monitoring inlet NO_x and adjusting ammonia injection.

521. In the Three Mountain Power case, supra, another case cited by TGC, the advocated lower CO limit had only been achieved on distinguishable sources, and the CO limit was based on a 3-hour average not a 30-day average, as with TGC. Also, Petitioners urge that TGC's reliance on the Steel Dynamics case, supra, is misplaced because a safety factor was allowed because Indiana was setting the most stringent level ever. While Dr. Fox did testify that

a safety factor could be incorporated if there is a basis for one, TGC's 30-day average incorporates a safety factor by averaging out the peaks. 6-2-04 TE.

Petitioners urge the NO_x limit is not consistent with other contemporaneous permits

522. Petitioners claim that it is irrelevant that TGC can point to other permits issued before and after its permit that contain the same or higher limits because BACT is determined by examining the lowest, not the highest, rates. 6-16-04 TE at 10:8-11:11 (Fox); P160 at 26 (Shepherd).

523. Petitioners point out that the 0.08 NO_x level appeared in TGC's solicitation for bids even before the final permit application was submitted and almost a year before the public comment period ended. P68A, TGC's AQCS Bid Package by B&V, July 27, 2001 at pg. 32; 11-14-03 TE 55:24; TE 57:15-24 (Dr. Fox). Thus, Petitioners contend that vendors simply bid on the 0.08 level rather than going through a top-down analysis to determine what the best available control technology actually was. They urge that the 0.08 NO_x level was negotiated among Peabody and the commenting agencies and was specified by Black & Veatch in the bid package for vendors to bid on.

524. Petitioners point to EPA notes from a May 14, 2002, meeting which indicate that the NO_x BACT limit was negotiated in exchange for dropping other issues raised by EPA and NPS. PR247 and 249; 6-1-04 TE at 109-115. Petitioners urge that when negotiation results in a limit that is not consistent with BACT, it is contrary to law and fact. In the recent <u>Alaska</u> case, supra, the applicant negotiated an alternative approach to NO_x control with the agency, which did not satisfy BACT. The U.S. Supreme Court remanded the decision.

525. Much of the disagreement over the NO_x limit revolves around what sources of information should be included in a BACT analysis. Petitioners identified the following sources

of data which they urge indicate that TGC's NO_x emission limit is not BACT – vendor guarantees, vendor literature, performance tests, CEMS data, draft permits, final permits, PSD applications, regulations published by other states, letters written by EPA and other state permitting authorities, BACT determinations by the EPA, foreign experience, industry newsletters, EPA technical reports and papers published in conference proceedings, among others.

Conclusions on BACT for NO_x

526. Petitioners have demonstrated that there were many facilities with higher NO_x reduction and lower emission limits that were not considered in TGC's BACT analysis. TGC has attempted to deflect the barrage of exhibits adduced by Petitioners by discounting the type of information and urging that the poor quality of its coal prevents a lower emission limit. TGC did not cite to the poor quality of its coal in its BACT analyses, however, and Fox and Shepherd, and even TGC witness Lillestolen, explained that the quality of the coal is a design parameter.

527. While acknowledging a few permits which were issued in late 2002 with NO_x limits of 0.07, TGC also urges that its NO_x limit is consistent with other permits issued in the same time frame. The Cabinet states that there were no permits in Kentucky with a NO_x emission limit of 0.07 at the time the TGC permit was issued. Both of these arguments demonstrate either a lack of understanding of the requirements of BACT or a willingness to say one thing publicly and do another. A BACT limit is not based on a limit which is in accord with other permit limits, or on permit limits in Kentucky.

528. TGC also disparages the types of data Petitioners rely on as showing lower limits and higher efficiencies. However, neither EPA nor Fox and Shepherd, the experts with the most BACT experience, agree with TGC's arguments that much of the information adduced by

Petitioners need not be analyzed. With regard to each of the types of information, i.e. retrofit plants, CEMS data, PRB coal, Petitioners have explored why this information is relevant. Indeed, in a top-down BACT analysis, following the NSR Manual, as TGC repeatedly cited to as its guidance for a BACT analysis, a comprehensive search is made. Not only did TGC fail to list facilities identified in countless sources which were achieving lower emission limits and higher reduction efficiencies, documents from its files show that it was aware of lower limits which were not disclosed to DAQ. Moreover, all of the facilities TGC did identify with lower emission limits in its revised BACT analysis, Table 4.2-1, Jt. #33, at Red 21, were excluded and did not go through a formal top-down BACT analysis. Thus, the technical feasibility of meeting a lower NO_x limit was not documented in the permitting record, nor did TGC perform any cost-effectiveness analysis for NO_x.

529. In addition, contrary to the Cabinet's assertions, Kentucky's BACT definition, 401 KAR 51:017 Section 1(8), states that BACT "means an emissions limitation … based on the maximum degree of reduction…" Thus, it was incumbent on TGC to disclose the degree of reduction and on DAQ to consider this measure of efficiency in determining the BACT emission limit for the PC boilers.

530. DAQ does not explain in the SOB, Jt. #7 at 20, why lower NO_x limits were not selected, and justifications provided by TGC following the close of public comment, Jt. #17 at 107-108, are conclusory.

531. Based on the foregoing, DAQ's determination to issue the permit with a NO_x limit of 0.08 lb/MMbtu was contrary to fact and law, and the permit should be remanded for a new NO_x BACT determination.

E. BACT for PM or PM_{10}

532. Revision #2 includes an amendment providing that the reference in Section D.1 on p. 35 of 50 is clarified to state that the regulated particulate matter pollutant is "PM/PM_{10} (filterable and condensable)".

533. Petitioners agree that this is an appropriate BACT limit at the time the permit was issued. Thus, this issue is moot.

F. BACT for SO_2

Overview

534. The permit sets two SO_2 limits: (1) 0.167 lb/MMbtu based on a 30-day rolling average, and (2) 0.41 lbs/MMbtu based on a 24-hour average. Jt. #8, pg 3, Sec. B(2)(c) and (d). The 30-day limit corresponds to 98% SO_2 reduction; the 24-hour limit corresponds to 95.2% SO_2 reduction. The technology for achieving these limits are the wet flue-gas desulfurization system (FGD) and wet electrostatic precipitator (WESP). Jt. #7, p. 21-22; Jt. #57 at Red 44-45.

535. Petitioners maintain that the Cabinet did not make an SO_2 BACT determination, but instead reviewed the proposed control technologies in conjunction with information available in the US EPA's RACT/BACT/LAER Clearinghouse database and other similar sources. Petitioners urge that the BACT determination is not satisfied by a technology review because a BACT analysis requires that an emission limit be selected based on the maximum degree of reduction that is achievable.

536. TGC and the Cabinet maintain that DAQ evaluated the information submitted by TGC, conferred with EPA and NPS, and made a reasoned determination of BACT for SO_2 in accordance with the requirements of 401 KAR 51:017. Contrary to Petitioners' assertions,

Respondents urge that technology capable of continuously achieving 99% reduction of SO_2 was not commercially available.

Findings - BACT for SO_2

537. In its original February, 2001, application, TGC proposed an SO_2 limit of 0.294 lb/MMbtu as BACT, on a 30-day average. Jt. #61 at Red 55.

538. In April, 2001, DAQ received a letter from the superintendent of the Park indicating that based on its review of the TGS air quality analysis it found that the proposed emissions would adversely impact visibility at the Park. TGC22. To address these concerns, Peabody visited plants in both the U.S. and Europe to look at pollution control technologies and determine what was achievable and what could be guaranteed commercially. TGC considered a number of different technologies including the following: wet FGD with limestone; wet FGD with magnesium enhanced lime (MEL); WESP; spray dry absorber; circulating dry scrubber (CDS); and emerging wet ammonia scrubbing technology. Jt. #61 at Red 36-44. In its evaluations, TGC concluded that CDS, which was capable of greater than 95% control, had not been used on units the size of TGS. It also concluded that CDS and MEL were no more effective at removing SO_2 than the combination of wet FGD and WESP.

539. TGC determined that wet FGD (wet flue gas desulfurization system) with limestone injection and WESP is capable of continuously achieving 98% reduction of SO_2 emission based on TGC's design-basis coal, resulting in TGC's proposal of a limit based on 98% reduction or 0.167 lb/MMbtu on a 30-day average. Jt. #7, p 21-22. Prior to TGS, experience with scaling up a WESP for use in a large coal fired power plant was limited. 3-16-04 TE at 30-31 (Lillestolen).

540. The complete Air Quality Control System (AQCS) Bid Package, P177, sent out by Black & Veatch, Peabody's engineer for the project, includes a letter dated July 27, 2001, entitled Letter of Invitation for Bids. The letter states that the bidder is to submit (as a minimum) a base bid of either Configuration 1 or Configuration 2 or both. These configurations are reflected on P137-362. Configuration 1 and 2 show 98% SO_2 and SO_3 removal. The letter, P177, also states that in addition to one of the above base bid system configurations please consider an optional system bid for the design of installing a semi-dry lime flue gas desulfurization system dedusting equipment in series with a wet flue gas desulfurization system. The optional system referred to is Option 1 on P137-362 at TB004617, with 99% SO_2 and SO_3 removal.

541. P180 is Black & Veatch's AQCS Bid Evaluation. It states that the AQCS invitation for bids was sent to eight bidders. AQCS proposals were received from ALSTOM and Lurgi. The Lurgi bid was for 98% removal for SO_2[57]. TGC decided to choose ALSTOM and not Lurgi because certain final information was never received from Lurgi.

542. Although TGC contends that it sought 99% removal from vendors, no vendors guaranteed 99% SO_2 removal, which TGC urges means that technology capable of continuously achieving 99% reduction of SO_2 was not commercially available. For this

[57] P137-92 is a summary dated July 30, 2001, of the Lurgi AQCS technology presentation. Lurgi was a vendor for the circulating dry scrubber. Paragraph 6 on p. 2 indicates that SO2 removal of greater than 99% is possible but may not be guaranteed.

reason, Ms. Tickner said that TGC committed to the 98% removal emission limit which it believed would perform over the long term.

543. TGC's top-down BACT analysis did not evaluate 99% SO_2 control. Jt. #33, Sec. 4.4.2; Jt. #57, Sec. 4.2; Jt. #61, Sec. 4.2; Jt. #7, pg 17-23. A higher control efficiency necessarily leads to a lower emission rate. Ms. Tickner stated that TGC did not include in its BACT analysis an evaluation of the feasibility of obtaining 99% removal because it did not get a guarantee for 99%. A guarantee would have demonstrated to Ms. Tickner that a technology was commercially available.

544. Ms. Tickner acknowledges that TGC developed its SO_2 removal targets based on looking at visibility impacts, but she states that was not the only criteria used. Ms. Tickner is asked whether the achievability of emission reductions in P137-76, entitled "CALPUFF Iterations on Emission Rates To Drop Visual Impact Below 10 Percent" (which included 99% removal of SO_2), was evaluated in the BACT analysis. She thinks they were included in some perspective in that TGC indicated in its BACT analysis that 98% was the highest achievable SO_2.

545. P137-5 is a "List of Air Permitting Concerns", which was produced from TGC files during discovery. When asked whether it indicates that the technology was selected and the limits and the BACT analysis was developed to justify those limits, Ms. Tickner responded: "I don't know if justify the limits is the right word, but, yes the BACT analysis was done on the technology selected petition." 12-5-03 TE at 130:11.

546. In May 2002, EPA raised concerns about the protection of the short-term SO_2 NAAQS and PSD increment by a BACT limit with a 30-day rolling average compliance period. In response, TGC submitted additional modeling in support of a short-term 24-hour block average SO_2 limit of 0.41 lbs/MMbtu. Jt. #22 and 23. Respondents state that this short-term limit

was never intended to be a BACT limit. Jt. #7 at 21-22; Jt. #17 at Red 22-31. To address concerns raised by the NPS regarding visibility at the Park, the permit contains a provision for adjusting the short-term limit downward based on actual operations data, as follows:

> The permittee shall perform an optimization study to re-examine the 0.41 lb-SO_2/MMbtu 24-hour emission limit for emission units 1 and 2 after the initial compliance demonstration and two years of commercial operation of unit 1. The results of that study will be used to revise the 24-hour SO_2 limit with a target emission rate of 0.23 lb-SO_2/MMbtu…..
> Jt.#8 at Section D; Jt. #7 at 34.

Expert Opinions on BACT for SO_2

Dr. Phyllis Fox

547. PD153-9, is a demonstrative exhibit prepared by Dr. Fox entitled Candidate SO_2 BACT Limits, showing that a reduction from 98% removal to 99% removal efficiency results in SO_2 reductions being reduced from 11,000 tons/year down to 5,000.

548. Dr. Fox opined that technologies which were not evaluated and could achieve greater than 98% are a dry scrubber and a jet bubbling reactor. An ALSTOM publication entitled "FGD Technologies, Achieving SO_2 Compliance at the Lowest Life Cycle Cost", illustrates a number of ways to improve the performance of a wet FGD system.

549. Dr. Fox cited a number of exhibits showing technologies which result in lower SO_2 emissions than TGC's permit limits.[58]

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[58] P123-156 is Lurgi's response to a request for Budget Quotation Prepared by Black & Veatch for a sulfur removal process for the TGC facility. Lurgi's circulating dry scrubber has some distinctive advantages over the wet scrubber selected for the TGC plant because it not only removes sulfur dioxide, but removes all of the sulfur trioxide, obviating the need for the downstream WESP.
P137-87 is a monthly progress report from Black & Veatch covering the period May 3 through July 13, 2001. The report indicates that there are three options presented in the air quality control system specification for particulate, SO_2, and SO_3 removal. The first option offers a CDS/Baghouse combination for 98/99 percent removal of each specie. Secondly, a baghouse or ESP/wet limestone FGD/wet ESP combination is offered for 98%/98% removal of each specie. Lastly, is a CDS/baghouse/wet FGD combination for 99%/99% removal for each specie. Each specie refers to SO_2 and SO_3. It states that the final selection will be based on permit requirements and the evaluation of the equipment bids.

P137-62 is a presentation by Babcock & Wilcox entitled B & W Wet FGD Technology which summarizes some of the high SO_2 removal performance data for plants that B & W have supplied. Plants D & E, and E in particular, indicate a percent of SO_2 removal greater than what the TGC permit is based on. TGC did not review the option of meeting the higher percent removals presented in this presentation.

P137-19 is a summary of an EPRI DOE SCS Demonstration Project for the Chiyoda, CT-121 process, which is a jet bubbling reactor SO_2 scrubbing process, which is licensed by Black & Veatch in the US (as announced in August, 2001). It is a demonstration at Georgia Power's Plant Yates. CT-121 at Plant Yates exhibited excellent availability, maintained greater than 97% limestone utilization, and demonstrated the ability to exceed 98% SO_2 removal efficiency with high sulfur coals while at maximum boiler loads. The fuels they tested ranged from 1.5 to 4.3% sulfur. Another notable thing about this technology is it has the ability to simultaneously remove PM_{10}. When operating at a removal efficiency of 99.3%, the CT-121 achieved PM_{10} outlet loading of 0.010, which is lower than the .018 proposed for this project. When operating at a removal efficiency of 98.5%, it achieved a .005 pounds per MMbtu particulate emissions rate. When operating at 98%, it achieved 0.006 pounds per MMbtu. This particular wet FGD scrubbing system has the dual benefit of removing not only SO_2 but also particulate matter.

P123-164 is a paper describing the commercial experience using the CT-121 FGD system at a 700-MW electric power plant in Japan. The inlet SO_2 concentration can be varied or the load of the power plant varied without any effect on the ability of the CT-121 to maintain a stable 99% removal efficiency.

P137-137 is a letter from a German company, WULFF, dated September 27, 2001, which in part is responsive to Black & Veatch's bid specification package for the sulfur removal train for the TGC project. It states that for the extreme high SO_3 removal rate, several measurements have shown more than 99%.

P137-30 is a paper presented by WULFF, at the Pittsburgh Coal Conference in September, 2000, entitled "Dry Flue Gas Scrubbing in Heat and Power Stations, Operating Experience with Medium and Large-Sized Units". In summary, it concludes from the favorable design and operating reference to date that the GRAF, WULFF, RCFB technology can be employed beneficially and without risk in medium and large size flue gas scrubbing plants of single-train design serving units with inlet raw sulphur gas flow rates as great as approximately two million cubic meters an hour and for gaseous pollutant removal efficiencies up to 99%.

P137-362 is a chart from TGC's files that summarizes five emission control options that were being evaluated to reduce visibility impacts to address comments by the NPS. The highest control efficiency that was evaluated has a pollution control train consisting of SCR, lime injection, CDS (circulating dry scrubber), baghouse, and a wet FGD. That particular pollution control train was capable of reducing SO_2 by 99%, and no days with visibility impacts over 10%. The reduction from 98% removal efficiency to an emission rate corresponding to 99% removal efficiency would cut emissions in half. The second page of P137-362 comes from the Black & Veatch bid specification package. It shows the option of SCR, lime injection, circulating dry scrubber, baghouse, wet FDG with a 99% SO_2/SO_3 control. The fact that this schematic was included shows that Black & Veatch considered it to be feasible.

P137-53 is the proposal where McDermott Technology, a subsidiary of Babcock & Wilcox, partners with TGC to propose an ultra-low emissions facility called the Thoroughbred Ultra Low Emissions Project. This demonstration will achieve 99.5% SO_2 removal.

P120-14 (admitted by avowel only) shows the results of test results conducted from February, 2001, to December, 2001, labeled Field Performance, Minnesota Power's Boswell Energy Center, showing a sulfur dioxide removal of 99.98%, using the Pahlman process.

P166, is an independent test report available by Interpoll Laboratories, entitled Results of the November 8, 2001, Air Emissions Monitoring, EnviroScrub Technologies, Mobile Demonstration Pilot Scrubber Ducts at Minnesota Power's Boswell Energy Center in Cohasset, MN. It found a 99.824% removal efficiency for SO_2.

P25, the Babcock & Wilcox "How Low Can We Go?" article supports Dr. Fox's opinion that SO_2 reductions greater than 98% should have been evaluated as part of the BACT analysis for TGC. It states that an advanced plant can be designed to achieve 99.5% SO_2 removal with high-sulfur coals. The coal sulfur concentration considered in this analysis is 4%. TGC's sulfur content is roughly 4.4%, so this analysis is based on a coal which is similar to TGC's coal. Dr. Fox adds that this is the level the Georgia Department of Natural Resources stated was BACT for purposes of evaluating the Longleaf application and in fact the Department rejected an application for a coal-fired power plant because the BACT analysis did not review that level. (P120-7, March 6, 2002).

550. Shepherd opined that taking TGS's coal into consideration, its 30-day rolling average looks very good. However, on a 24-hour basis, he said TGC's limit is too high. There are other boilers achieving a higher level of control on coal with less sulfur. He, thus, expected that TGC could do as well as the Conemaugh and the Harrison boilers he mentioned. P160 at 86 and 101. Shepherd also opined that all limits – including the 24-hour limit – should meet BACT.

Handy and Lillestolen

551. TGC maintains that the control technologies chosen, wet FGD with limestone injection and WESP, are the top technologies for TGS. Handy and Lillestolen stated that TGS is one of the first coal-fired power plants to use a WESP along with the wet FGD to control SO_2 emissions.

Parties' Arguments on BACT for SO_2

Petitioners

552. Petitioners urge that TGC's SO_2 30-day limit of 0.167 is not BACT, and that TGC was aware that 99% was the maximum degree of reduction, but did not provide DAQ with evaluations of 99% control. Petitioners offer the following as support for this contention:

* A consent degree requiring the retrofit installation of FGD at three older coal-fired units, which are required to meet a 30 day limit of 0.150 and a 24 hour limit of 0.25 limit. TGC200, p. 15, para 53 and 55, p. 16, para. 57;

* Black & Veatch's report for engineering work at TGC showing a CDS/Baghouse/Wet FGD combination of 99/99 removal of SO_2 and SO_3, P137-87 at 2 (TB007371);

* ALSTOM had provided SO_2 removal systems which performed at greater than the 98% TGS's 30 day limit is based on, P123-165;

* Babcock & Wilcox achieved SO_2 removal above 98% using the wet FGD device planned for TGS, P137-62 at TB006436;

* WULFF also stated it had installed FGD systems which perform at greater than 99% removal, P137-137 at TB005307;

* P137-7 shows that 99% removal was achievable with a CDS and wet FGD system, at TB001872;

*MEL FGD was in use prior to the TGC permit – 6-1-04 TE at 213-223 (Fox);

*Petitioners also cite to additives and a jet bubbling reactor as feasible technologies for achieving control greater than 98%. 11-13-03 TE at 80; 6-1-04 TE at 211; 12-3-03 TE at 89 (Fox): P123-164.

553. With regard to the 24-hour limit, which represents a level of control of slightly less than 95%, Petitioners point out that Shepherd's chart showed 29 facilities with limits of below 0.41 for a 24-hour averaging period. P160-2 at Table 2.a. They also point to Shepherd's testimony that a 24-hour limit should be approximately 25 to 30% higher than a 30 day limit for SO_2. With a 30% increase, TGC's 24-hour SO_2 limit would be 0.22 lbs/MMbtu. P160 at 36, 46.

Cabinet

554. Respondents' arguments on SO_2 control are relatively brief. The Cabinet states that the 30 day rolling average of .167 lbs/MMbtu is the BACT limit; the 24-hour limit is not a BACT limit, and the two limits together protect visibility and guard against NAAQS violation. The Cabinet also comments that the control train is appropriate for eastern power plants.

TGC

555. TGC urges that the evidence supports the following contentions: 1) it selected the top control technology; 2) 0.167 SO_2/MMbtu is BACT; 3) 99% reduction is neither continuously achievable nor commercially available; and 4) the short term SO_2 limit is not intended to be a BACT limit.

Petitioners' Reply

556. Petitioners urge that the SO_2 emission rates were selected by TGC based on visibility and then put out to bid. A vendor was selected (ALSTOM), and the BACT analysis was then revised to conclude that the technology that ALSTOM proposed was BACT. The use of this process is supported by P137-116, meeting notes between Black & Veatch and client TGC. The meeting notes, at TB7589 note 12, state: "(d)evelop BACT analysis based on control technology selected."

557. Petitioners contend that the process used by TGC in selecting its SO_2 limits is inconsistent with the definition of BACT, which requires that the BACT emission limit be based on the "maximum degree of reduction". Petitioners contend that a four step process was followed by TGC in selecting the SO_2 limits:

> (1) run air models to determine maximum SO_2 emission rate that addresses NPS visibility issues at the Park;

(2) adjust mine plan to achieve desired sulfur content;

(3) request vendor bids for the SO_2 emission rate selected in step #1 and coal sulfur in step #2;

(4) adjust the BACT analysis to agree with the technology selected in step #3.

558. Petitioners urge that while several technologies that were able to achieve 99% plus SO_2 removal were evaluated by TGC, they were not selected as BACT because a higher SO_2 control efficiency was not required to resolve the visibility issues. Petitioners point out that the record contains no support for eliminating the top SO_2 control technologies, and they urge that testimony in the formal hearing which addresses some of the eliminated top technologies are *post hoc* rationalizations and were not before the Cabinet at the time the permit was issued.

559. TGC presented a cataloguing and description of control technologies. In the BACT analyses in the February, 2001, application (Jt. #57, pg 4-12, Table 4.2-1) as well as the October, 2001, application (Jt. #61 pg 4-11, Table 4.2-1), the same control efficiency of 90%+ is assigned to all SO_2 emission control options. For some of the SO_2 control options, the control efficiency is revised to 95+% in the May 2002 Addendums. Jt. #33, pg 30, Table 4.4.2-1. Petitioners urge that by assigning the same removal efficiency to all of the potential scrubbing technologies, it appears as if they are all comparable, when they are not. 12-3-03 TE at 85:10-15 (Dr. Fox).

TechnologiesPetitioners urge should be included in the BACT analysis

560. Petitioners cite to the following technologies which they urge should have been included in the BACT analysis as the top technologies regardless of vendor guarantees and should have been eliminated as technically infeasible only based on documentation that physical, chemical and engineering principles would preclude successful use.

a. *Bubbling jet reactor* – This technology can achieve greater than 98% SO_2 control and thus would have resulted in lower SO_2 emission limits. 6-1-04 TE 211:21-212:1 (Fox). Petitioners adduced evidence showing that the Chiyoda CT-121 jet bubbling reactor is able to maintain 99% SO_2 control over the long term. 12-3-03 at 89:13-15 (Fox). The operating history, P123-164 at pg. 6, shows continuous performance above 99%.

Although TGC claims to have solicited the vendor of the CT-121, this is not reflected by the record. The only vendors who offered this process at the time of the Black & Veatch solicitation, July 27, 2001, were Chiyoda and BWE, and the bidder lists in P177 indicate that the request for proposal did not go to these vendors. Although Black & Veatch became a licensee of the CT-121, as announced in a press release on August 29, 2001, it was not a licensee when the bid package was released. PR312. The Shinko-Kobe facility discussed in P123-164 is not clearly distinguishable from TGS, as TGC claims. Although Shinko-Kobe burns coal with about 1% sulfur, which is much lower than TGC's coal, it is more difficult and costly to remove the same high percentage of sulfur from a low sulfur coal than a high sulfur coal. As explained earlier in this Report, a higher SO_2 efficiency likely could be achieved on a higher sulfur coal because the design SO_2 removal efficiency *increases* and the cost per ton of SO_2 removed *decreases* as the sulfur content of the coal increases. Jt. #33, p. 35 ("The removal efficiency of the control equipment is lower for more dilute washed streams."); 1-5-04 TE at 113:20-23;

117:14-118:13 (Tickner – "It's my understanding as the quality of the coal gets worse, it's easier to get a higher removal efficiency."). The experience reported in P123-164 at p 15 is relevant to high sulfur fuels, i.e. as high as 6 lb/MMbtu or more (TGS's design sulfur content is 8.5 lb/MMbtu) and at a plant with an inlet concentration of 7,000 ppm SO_2 (TGS's inlet SO_2 concentration is 3,249 ppm).

b. CDS/wet FGD combination - The BACT analysis did not consider combinations of technologies, with one exception, and did not evaluate Circulating Dry Scrubber (CDS) plus wet FGD as the top technology at 99% control in the BACT analysis. 12-5-03 at 80:2-13 (Tickner). P137-7, the Air Quality Control System Performance Matrix apparently prepared by Black & Veatch, was not submitted to the Cabinet (12-5-03 TE 34:2-5 – Tickner), although it documents a higher SO_2 removal efficiency and a lower SO_2 emission limit than the BACT permit limits. This matrix shows that a circulating dry scrubber plus a wet FGD can achieve greater than 99% SO_2 control with an "expected" removal of 99% and an SO_2 emission limit of 0.1 lbMMbtu. The removal efficiency for the upper end of the moderate risk range is 99%. P137-7; 12-5-03 TE at 24:5-26:19; 29:10-33:2 (Tickner). This risk level is consistent with that selected for SO_2 and SO_3.

c. *Furnace lime injection plus CDS and/or wet FGD* - A Black & Veatch June 2001 report, "Emission Control Evaluation", concluded a number of controls could be used to "achieve greater performance" than what was then (June 2001) proposed. P137-61, p. 2. One of these was injecting a calcium-based sorbent, typically lime or limestone, into either the boiler or the ducting of the air pollution control system. Id. at 3-5. The Black & Veatch analysis indicates that sorbent injection could achieve 30 to 75% SO_2 removal, beyond that achieved by the wet FGD. Id. at 5. This would increase the total SO_2 removal from 98% up to 99.5%.

In a subsequent July 2001 analysis, entitled “scrubber options per unit numbers”, Black & Veatch evaluated lime injection into the boiler in combination with various other SO_2 control methods. P137-93. Option 6 is lime injection coupled with a CDS, fabric filter or ESP and wet FGD (“double scrub”). Black & Veatch concluded “double scrub” would achieve 99% SO_2 control. Id. The risk column indicates that the performance risk is low to medium, which is lower than the risk level for the pollution control train that was selected. P137-7. P137-93, note 3, indicates that the “pollutant levels are equipment guarantee levels”. The Black & Veatch bid package for the steam generator and SCR included lime injection into the boiler. P137-87, p. TB7371.

The February 2001 BACT analysis briefly discusses injecting a sorbent into the ducting but did not mention injecting lime into the boiler and did not evaluate sorbent injection in combination with other SO_2 controls. Jt. #61, p. 4-16 to 4-17. The October 2001 BACT analysis eliminated the section on sorbent injection, without an explanation of why it was being eliminated from consideration. Jt. #57, Sec. 4.2; Jt. #61, Sec. 4.2.

d. Additives - Various chemicals can be added to wet FGD systems to increase SO_2 removal, including organic acids like adipic, dibasic and formic acids. P137-51, p. 3-3; 12-12-03 TE at 90:20-92:14 (Tickner); 3-16-04 TE at 63:15-71:1 (Lillestolen). Babcock & Wilcox, in response to the Black & Veatch bid package, proposed to increase the SO_2 removal beyond 98% using “acid addition”. P137-151. Handy did not directly answer questions on whether additives were included in the BACT analysis, claiming they were always part of the project. 5-10-04 TE at 87-6 – 88:23 (Handy). The BACT analyses and SOB do not mention additives. Jt. #33, Sec. 4.4.2; Jt. #57, Sec. 4.2; Jt. #61, Sec. 4.2; Jt. #7, p. 17-23. The record suggests that these additives were not part of the project. Black & Veatch asked vendors if they were willing to guarantee their SO_2 control level without the use of dibasic acid. P137-64, item 4. ALSTOM responded that its "limestone FGD system is designed to meet the guaranteed sulfur dioxide emission without the use of dibasic acid." P180, p. TB6977.

e. <u>WESP is not an SO_2 control technology</u>

Although TGC claims in its post hearing brief that WESP is an SO_2 control technology and claims that wet FGD and WESP are the top technologies for SO_2 control, WESP was required in the control system only because TGC chose a wet FGD instead of a CDS. The wet FGD creates sulfuric acid mist that must be eliminated with downstream equipment. P137-151, p. 8-2 to 8-3. TGC42, a demonstrative showing the control system train, does not show WESP as an SO_2 control.

Petitioners urge that 99% control efficiency was feasible

561. Petitioners maintain that 99% control can be achieved over the life of this facility and has been achieved. As explained earlier, the higher sulfur content of TGS's coal makes it easier to achieve a higher degree of SO_2 reduction. Several sources were identified by Petitioners that are or have been continuously meeting 99% SO_2 control, including the Shinko-Kobe Power Plant, P123-164, and Mitchell 3, an Allegheny plant in PA, which operated at 99% under a consent decree in 1984 and 85. 6-1-04 TE at 220:15-25 (Fox).

562. Lillestolen admitted that ALSTOM was not asked to guarantee higher than 98% SO_2 removal. 3-16-04 TE at 165:4-7. A 99% control efficiency would result in an SO_2 emission rate of 0.085 lb/MMbtu, two times lower than TGC's 24-hour SO_2 emission limit of 0.167 lb/MMbtu.

563. The BACT analysis did not disclose that CDS and MEL (magnesium enhanced lime) are capable of achieving 99% SO_2 control. These technologies were eliminated in Step 2

of the BACT analysis (technically infeasible) without providing any rationale or identifying any energy, environmental or economic impacts and other costs.

564. TGC selected the technology bid by ALSTOM without explaining why other, more efficient technologies were not BACT. It appears that the SO_2 control technology proposed by ALSTOM determined the outcome of the BACT analysis. In meeting notes taken September 17, 2001, between Peabody, Mirant and Black & Veatch, it is stated: "Develop BACT analysis based on control technology selected. Will not know until after selection is made …" and also Item F: "FGD and Acid Gas controls and emission limits – Information will be available once vendor bids are provided." P137-116, p TB7589. The record suggests that TGC selected wet FGD because it was the cheapest technology. P137-51, p 1-2 and Table 1-3, p 1-6. P137-145 at KEC31426 shows that wet FGD costs $146 per ton of SO_2 removed while CDS costs $164 per ton. This cost effectiveness analysis, prepared by Black & Veatch based on vendor quotes and EPA guidance, was sent to Handy, but was not disclosed to the Cabinet or included in the BACT analysis. 12-10-03 TE at 162:4-163:5 (Tickner).

565. TGC and the Cabinet evaluated CDS, CFB, and other controls as though they were capable of achieving the same SO_2 control efficiency as all other SO_2 control technologies, 90+% or 95+%. Thus, they never distinguished the upper end of the removal efficiency range for the various SO_2 control technologies. Jt. #33, Sec. 4.4.2; Jt. #61, Sec. 4.2; Jt. #57, Sec. 4.2; Jt. #7, p. 19-22, Table 5.2.

566. Tickner acknowledged that the BACT analysis did not evaluate CDS as capable of achieving 99% SO_2 control, 12-5-03 TE 78:4-6, and also that TGC did not reveal to the Cabinet that it had evaluated CDS for 99% SO_2 removal. Id. at 111:24-112:1. In a report Black & Veatch prepared, dated March, 2001, which evaluated three SO_2 control options for TGC –

wet FGD, MEL and CDS, reported one of the advantages of CDS "in this application", compared to the other two technologies, was its "High SO_2 removal." P137-51, p. 5-11.

567. Lillestolen admitted he was aware that MEL had been used to achieve 99% SO_2 control. 3-17-04 TE at 34:18-35:1. Dr. Fox, referring to PR306 at 2478, confirmed that EPA argued that the MEL process achieved 99% SO_2 control in the Longview case, based on units that had been guaranteed before the TGC permit was issued.

568. In rebuttal, Petitioners introduced a letter of deficiency the Cabinet issued in January, 2004, in the Cash Creek PSD application stating "U.S. EPA recently determined that 99% SO_2 removal was possible and practical using MEL scrubbers. This level of control would reduce emissions by half from those in the application." PR237, p. 3. The vendor of the MEL process has filed comments in other proceedings, stating that the MEL process has achieved 99% control on similar coals. 6-1-04 TE at 212:20-220:14 (Fox). Referring to PR231, a paper presented by the vendor of the MEL FGD process, Dr. Fox stated that on p. 2 of PR231 there is a list of facilities with commercial scale FGD systems, many of which significantly predate the TGC permit. 6-1-04 TE at 212:20-213:3 (Dr. Fox). See also PR306, p. 2478; PR317, which post date the permit.

569. TGC's BACT analysis, at Jt. #57, at Red 38-39, suggests that the use of MEL is "often site specific" and high removal efficiencies are not always attainable. However, the BACT analysis did not identify the so-called site specific factors or indicate whether they are relevant to TGC.

570. Although TGC claims that CDS was eliminated because it had not been used on units the size of TGS, the BACT analyses in Jt. #57 and 61 do not state that CDS was technically infeasible for TGS on the basis of size. 12-5-04 TE at 77:19 –78:3 (Tickner). Further, Black &

Veatch prepared a report in March 2001 for TGC which evaluated CDS on an 850 MW gross (750MW net) boilers, P137-51 p 7-1 to 7-4, and concluded that it was technically and economically feasible. The advantages it found over the wet FGD system included the following: higher SO_2 removal, smaller space requirements, carbon steel construction, dry reagent handling, dry waste products, simple process control, lower sulfuric acid mist, absence of visible plume, and lower mercury emissions. Id. at 5-1 and Sec. 8.0. TGC did not disclose these advantages in its BACT analysis. The wet FGD was selected because it was the cheapest, P137-51, p. 1-2, even though it had disadvantages which were not disclosed in the BACT analysis. These include elevated sulfuric acid mist and a plume that is highly visible and persistent in all weather conditions and which can extend for several miles before dissipating. Id., p. 1-2, 8-1, 8-2.

571. The Black & Veatch analysis addressed the size constraint by specifying a two-train system, P137-51, p. 6-10, and found that CDS was more cost effective than wet FGD, when a WESP was included. P137-51, p. 1-2 to 1-3. This information was not submitted to the Cabinet, and TGC did not disclose to the Cabinet that it had evaluated using a CDS for 99% removal of SO_2. 12-5-03 TE at 111:23-112:4 (Tickner).

572. TGC claims it requested bids for both 98 and 99% SO_2 removal, but no vendors were willing to guarantee 99% removal. Thus, TGC concludes that technology capable of continuously achieving 99% reduction of SO_2 was not commercially available. Petitioners, however, point out three problems with this argument: 1) ALSTOM was not asked to guarantee a higher SO_2 removal efficiency than 98%. 3-16-04 TE at 165:4-7 (Lillestolen); 2) a vendor guarantee is not required to establish that a technology is feasible and available for purposes of BACT. Jt. #9, at B.20. (Petitioners point out that TGC does not have a vendor guarantee for

80% mercury removal, but concluded that it constitutes both BACT and MACT for mercury); and 3) Black & Veatch evaluated six SO_2 control options to address visibility concerns. P137-93. These included an option designed to achieve 99% control of both SO_2 and SO_3, using furnace lime injection, CDS and a wet FGD. A note to this table suggests that equipment guarantees were available at this level. Note 3 states "(t)he pollutant levels are equipment guarantee levels."

573. Ms. Tickner's testimony, which TGC relies on for its claim that no vendor would guarantee 99% control, is in contradiction to the Black & Veatch air quality control system bid package and other supporting information. P177. The letter of invitation dated July 27, 2001, accompanying the Black & Veatch AQCS bid package only required bids on either SO_2 Configurations 1 or 2. Id. at p. 1-2. These two configurations only require 98% SO_2 removal. Id. at p 727 of 761. See also P137-362. The 99% SO_2 option is the Option 1 Configuration, the third listed option. See P177, p. 727 of 761. The letter of invitation does not mention this option specifically, although it does describe the technology in this option: "In addition to one of the above base bid system configurations please consider an optional system bid for the design by installing a semi-dry lime flue gas desulfurization system and dedusting equipment in series with a wet flue gas desulfurization system." P177, 7-27-01 B&V letter, p. 2. Black & Veatch's evaluation of the bids, P180, supports Petitioners' contention that only 98% SO_2 control was requested. 12-5-03 TE at 106:21-25 (Tickner). Black & Veatch did not request bids for 99% control; instead, the 99% control configuration was optional and "was available for them to bid on…" 12-5-03 TE at 27:12 – 29:3 (Tickner).

574. Petitioners point out that the visibility concerns were addressed by controlling SO_2 by 98%. Thus, the 99% control issue is a factor which should have been considered for BACT, but was not. The higher control efficiency would result in a more expensive SO_2 control

system, which would be a disincentive to bidders. In addition, proposals are expensive and time consuming, and there was less than two months between the letter of invitation for bids and the date proposals were due. P177, 7-24-01 letter. Proposals were due about the same time under a separate solicitation for the steam generating unit and SCR system. TGC29. ALSTOM wrote Black & Veatch that it "will be pleased to provide alternatives to our initial bid, but we are unable to provide the option pricing requested by today due to the limited time available." P180 at TB006972. Thus, Petitioners suggest that it is unrealistic that any firm would provide proposals on multiple alternatives, especially an alternative that was optional and likely not to be selected based on cost alone.

575. Petitioners do not dispute TGC's assertion that not a single coal-fired permit in the country requires 99% removal. However, they point out that a permit is not necessary to demonstrate that a technology is available. Dr. Fox and Adams both testified that BACT limits are based on a wide range of sources, including vendor guarantees, source tests, technical papers, foreign sources and others. Indeed, in comments on the draft permit, the EPA recommended that TGC look beyond permits. P23.

576. Contrary to TGC's argument that Petitioners' evidence is theoretical because it is based only on *vendor* guarantees, Petitioners point out that TGC's 98% BACT level is based on a vendor guarantee.

Petitioners urge the short term limit should be BACT

577. Petitioners acknowledge that TGC does not intend for its 24-hour limit to be BACT. However, Petitioners urge that by citing to 401 KAR 51:017, TGC characterized its short term 24-hour limit of 0.41 lb/MMbtu as a BACT limit.

578. Petitioners cite to three sources to support their argument that the short-term limit should be BACT: 1) the NSR Manual, Jt. #9, at B.56, states that BACT limits must demonstrate protection of the short term ambient standards; 2) John Bunyak with NPS wrote in July 2002 that TGS should be required to meet a short-term limit that represents BACT, not arriving at a limit just below the Class I increment; 3) Shepherd testified that a BACT analysis should be done for all emission limits, not just one. P160 at 90:16-21.

579. Dr. Fox believes a BACT determination should have been made on both the three-hour and 24 hour short term SO_2 limits, but was not. She testified that it is common practice to establish permit limits with averaging times that correspond to the averaging times of ambient air quality standards for each applicable pollutant. The 24-hour SO_2 limit was selected to assure that the emissions were just below the threshold that would result in significant visibility impacts. 12-4-03 TE at 86-90.

580. Shepherd testified that he found two plants (Conemaugh in PA and Harrison in WV) that with even lower sulfur coal were achieving a higher level of sulfur dioxide removal, which would lead him to believe that TGC could probably do at least as well on a 24-hour average, which would result in a one third reduction in TGC's 24-hour emission rate. P60 at 25:11-25. NPS also expressed concerns that at the 0.41 lb/MMbtu limit there was a potential for an adverse impact on visibility at the Park. The concern would be eliminated if emissions were brought down to the .23 level. Id. at 45:5-25; 88:15 – 89:22 and at 36:7 to 37:3. (As stated, the permit contains a provision for adjusting the short-term limit downward based on actual operations data. Jt. #8, Section D; Jt. #7 at 34.; see also Jt. #18 and 19.)

Conclusions on BACT for SO_2

581. While TGC's applications contain a consideration of various technologies for controlling SO_2 emissions, these "evaluations" were summary in nature and fall far short of the technical feasibility analysis required by a Step 2 BACT analysis. As cited by TGC, a Step 2 analysis requires that "(a) demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review." Jt. #33, p 11; Jt. #57, p 4-4. In contrast, TGC did not show that the control technologies considered could not be successfully used at TGS based on physical, chemical and engineering principles. Instead, TGC made only general conclusions, as shown by the following examples.

582. With regard to the MEL process, TGC states:

> The MEL process has been demonstrated to be a technically feasible application for SO_2 removal on pulverized coal fired boilers. Additionally, as stated above, the MEL system is often site specific, and such high removal efficiencies are not always attainable on a consistent, long-term basis due to process control considerations.

Jt. #61 at Red 39.

583. With regard to the use of the Wet Scrubber (Limestone), TGC concludes:

> Just as with lime scrubbing, additives such as dibasic acid may be added to the scrubber liquor to improve the overall SO_2 removal efficiency. Removal efficiencies in the upper 90% range have been obtained in some customized applications. These high efficiencies are typically only achievable for short periods of time while using lower sulfur fuels. Id.

584. TGC had information which documented a higher SO_2 removal efficiency and a lower SO_2 emission limit than the BACT permit limits, as illustrated by P137-7, the Air Quality

Control System Performance Matrix apparently prepared by Black & Veatch, which was not submitted to DAQ.

585. Clearly, SO_2 reductions greater than 98% should have been evaluated as part of TGC's BACT analysis. Lillestolen admitted that ALSTOM was not asked to guarantee higher than 98% SO_2 removal. 3-16-04 TE at 165:4-7. Ticker acknowledged that TGC did not reveal to the Cabinet that it had evaluated CDS for 99% SO_2 removal, 12-5-03 TE at 111:24-112:1, and the BACT analysis did not evaluate CDS as capable of achieving 99% SO_2 control. 12-5-03 TE 78:4-6. Indeed, based on the evidence adduced by Petitioners, the control option of 99% removal of SO_2 should have been presented as a control option in the top-down BACT analysis, and if it were eliminated, TGC would need to show either technical infeasibility or lack of cost-effectiveness. A 99% control efficiency would result in an SO_2 emission rate of 0.085 lb/MMbtu, two times lower than TGC's 30-day SO_2 emission limit of 0.167 lb/MMbtu. Tickner acknowledged that Lillestolen admitted he was aware that MEL had been used to achieve 99% SO_2 control. 3-17-04 TE at 34:18-35:1. Dr. Fox, referring to PR306 at 2478, confirmed that EPA argued that the MEL process achieved 99% SO_2 control in the Longview case, based on units that had been guaranteed before the TGC permit was issued.

586. In a top-down BACT analysis, an applicant cannot take equipment bids and select a vendor based on the bid. However, a B&V progress report on TGS in the summer of 2001, in P137-87 at TB007371, states that "the final selection will be based on permit requirements and evaluation of the equipment bids". Just before this sentence, B&V states:

> There are three options presented in the AQCS specification for particulate, SO_2 and SO_3 removal. The first option offers a CDS/Baghouse combination for 98/98 removal of each specie. Secondly, a Baghouse or ESP/Wet Limestone FGD/Wet ESP combination is offered for 98/98 removal of each specie. Lastly, is a CDS/Baghouse/Wet FGD combination for 99/99 removal of each specie.

587. Again, this shows that TGC was aware that 99% was the maximum degree of reduction of SO_2 achievable. However, this was not submitted to DAQ for evaluation.

588. Moreover, an applicant need not have a guarantee in order for a technology to be considered "available". The NSR Manual, which TGC repeatedly states it followed, states under Step 2:

> Vendor guarantees may provide an indication of commercial availability and the technical feasibility of a control technique and could contribute to a determination of technical feasibility or technical infeasibility, depending on circumstances. However, EPA does not consider a vendor guarantee alone to be sufficient justification that a control option will work. Conversely, lack of a vendor guarantee by itself does not present sufficient justification that a control option or an emissions limit is technically infeasible. Jt. #9 at B.20.

589. TGC urges that "BACT limits are set based on what the facility can achieve continuously over the life of the facility under worst-case conditions". As stated before, while BACT limits are to be met over the life of the facility under worst-case conditions, this does not mean that the selection process for a BACT limit is defined by this criteria.

590. A remand is generally appropriate when an agency fails to examine the feasibility of a more effective control technology. The Board in In re Inter-Power in setting out the standard of review for remanding a BACT review, states that petitioners need to establish that the evidence in the record in support of their view clearly outweighs the evidence presented by the permit issuer in support of its decision.

> (I)t is important to distinguish between BACT decisions where the permit issuer failed to consider an "available" control option in the first instance and decisions where the option was considered but rejected. Where a more stringent alternative is not evaluated because the permitting authority erred in not identifying it as an "available" option, a remand is usually appropriate, because a proper BACT analysis requires consideration of all potentially "available" control technologies.

In re Inter-Power of New York, Inc., 5 E.A.D. 130, 144. (EAB 1994).

591. Also, the Board in In Re Masonite Corp., supra, at 551, 569, note 26, 5 E.A.D. (EAB 1994), found that the cost-effectiveness analysis was clearly erroneous because the permit issuer had rejected use of the existing RTO (regenerative thermal oxidizer) at the facility without an adequate cost-effectiveness analysis. Thus, the issue was remanded for reconsideration.

592. DAQ's SO_2 BACT determination was based on an inadequate analysis by TGC of the technical feasibility of meeting a limit of 99% reduction. Although testimony at the formal hearing addressed some of the eliminated top technologies, this testimony was not before DAQ at the time the permit was issued and, thus, amounts to post hoc rationalizations.

593. For the foregoing reasons, the permit should be remanded for a new SO_2 BACT determination.

594. I do not agree with Petitioners that the short term SO_2 limit must be BACT. Kentucky's BACT definition requires that for each pollutant an emission limitation must be set based on the maximum degree of reduction. It is not clear that if more than one emission limit is set it must also be BACT. Here, the 24-hour average was requested by EPA and DAQ to demonstrate the protection of the Class I NAAQS and PSD increment. The analysis to determine the short-term level was based on statistical analysis and modeling, not on revising BACT. Jt. #17 at Red 25.

595. Since the 30-day rolling limit is much less than the 24-hour level, TGS could only operate with emissions as high as 0.41 lbs SO_2/MMbtu over a very short time frame and still meet the 0.167 lbs SO_2 MMbtu limit. Id. at Red 27. "Without the 24-hour SO_2 average limit, SO_2 could actually be higher than 0.41 lbs/MMbtu so long as the 30-day rolling average is met. By adding the short-term limit, the acceptable range over which SO_2 emissions occur on a daily

basis is reduced. This provides greater protection, not only to NAAQS and increment, but also visibility." Id. at Red 30.

G. BACT for Mercury and Beryllium

Overview

596. The permit contains a mercury BACT limit of 0.0000031 lbs/MMbtu for each unit based on a quarterly average. Jt. #8, p. 3, Sec. B.2.k. This limit is based on 80% mercury control. The permit also contains a beryllium BACT limit of 0.000000944 lb/MMbtu for each unit based on a quarterly average. Jt. #8, p. 3, Sec. B.2.h. This limit is based on 99.5% beryllium control. The technology chosen to control mercury and beryllium is an ESP, WESP and WFGD. Jt. #7 at 18.

597. Petitioners urge that TGC eliminated methods to reduce mercury and beryllium that are "available" and technically feasible within the definition of BACT, including baghouses or fabric filters, carbon injection, carbon filters, additives, and coal washing.

598. TGC maintains that it considered all the commercially available control technologies that provide a co-benefit of mercury removal, including fabric filters. Although it originally proposed fabric filters for particulates including mercury, additional information from vendors led it to reconsider and conclude that fabric filters were not feasible because of the high sulfur content of the flue gas upstream of the wet FGD and the low temperature downstream of the wet FGD. 4-15-04 TE at 32 (Adams); Jt. #63 at 15.

599. As to the use of activated carbon injection (ACI), TGC determined in conjunction with EPA's MACT development group, that it was not commercially available as of October 11, 2002, and thus, they urge it was not required to be considered in its BACT analysis. 5-10-04 TE at 18-19 (Handy). EPA, in its proposed MACT for steam electric generators, also found that ACI

is still not commercially available. TGCR258 (69 Fed. Reg. 4652, 4698-99 (January 30, 2004)[59]. Adams testified that he was not aware of vendors selling ACI as of October 11, 2002. 3-16-04 TE at 88 (Adams).

600. TGC urges that there was a rational basis for DAQ's determination, and for this reason, it should be upheld.

601. The Cabinet urges that as of the date of issuance of TGS's permit, the control technology was state of the art and no guarantees of lower limits were being offered.

Findings - BACT for Mercury and Beryllium

602. In both its February, 2001, and its October, 2001, applications, TGC proposed a baghouse (i.e. fabric filters) as BACT for PM/PM_{10}, beryllium and mercury. Jt. #61, p 4-9; Jt. #57, p. 4-10.

603. In January, 2002, ALSTOM sent a letter to Peabody, Jt. #44 at Red 98. The letter was responsive to Peabody's request that ALSTOM guarantee a mercury emission. 3-16-04 TE at 74-82 (Lillestolen). ALSTOM was not willing to make a guarantee at that time, and stated that the best air quality control system for the TGS plant was dry ESP – wet FGD - wet ESP, for which it estimated that a prudent removal efficiency would be 80%. Jt. #44 at 99.

604. In Jt. #33, TGC's May 2002 Addendum, TGC eliminated language contained in its applications, Jt. #61, p 4-9; Jt. #57, p 4-10, concluding that a baghouse was BACT for beryllium and mercury. New sections on beryllium and mercury were added, Jt. #33 4.4.7.1 and 4.4.8.4, which conclude that ESP is the maximum degree of reduction. Jt. #33, p 53-54.

[59] See Overview on Count 10 for additional information on EPA's proposed MACT standard for steam electric generating units.

605. TGC states that it eliminated fabric filters based on an analysis by its engineer, Burns & McDonnell. Jt. #17 at Red 147-148. This two-page paper, entitled "Attachment 3 Baghouse Feasibility Analysis", is included in TGC's Responses and Comments on the second draft permit and submitted to DAQ with a date of September 16, 2002. The analysis states that long-term performance and bag life were concerns at a high-sulfur coal fired unit.

606. Ultimately, TGC and DAQ determined that fabric filters were not feasible because of the high sulfur content of the flue gas upstream of the wet FGD and the low temperature downstream of the wet FGD. Jt. #34. In DAQ's responses to comments, Jt. #63 at 15, it states:

> While the Division does not believe that the acidic and wet exhaust stream would automatically preclude the use of baghouse technologies, there are clear technical concerns that upon review justify the use of ESP controls.

Parties' Arguments on BACT for Mercury and Beryllium

607. The arguments in the post hearing briefs of Petitioners, the Cabinet and TGC are summarized in the overview of this Count.

Petitioners' reply brief contains the following arguments:

Petitioners' Reply

608. Petitioners point out that there is no requirement in 401 KAR 51:017 that a BACT technology be specifically designed to control the pollutant of interest, as TGC suggests. Instead, "available" technologies are defined by the NSR Manual: "Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation." Jt. #9 at B.5.

609. Petitioners urge that the following technologies to remove mercury and beryllium were commercially available: carbon injection, carbon filters, TOXECON™, and additives.

610. *Carbon injection* – Petitioners note that ALSTOM announced that it was offering commercial guarantees for carbon injection systems on December 2, 2002, six weeks after TGC's permit was issued and before the issuance of Revision #1 on December 6, 2002. P71. Thus, Petitioners surmise that ALSTOM was in a position prior to permit issuance to discuss carbon injection systems with TGC (3-16-04 TE at 146:7 – 150:13 (Lillestolen)) and offer to sell them in the near future, certainly well within the four-year construction period for TGC. 12-2-03 TE at 52:7-16 (Fox). Moreover, Petitioners point out that ALSTOM is only one vendor of these systems, and Dr. Fox indicated that there were European vendors with carbon injection in use on coal-fired power plants in the late 1990s.

611. In addition, carbon injection is widely used on similar sources, i.e., the waste-to-energy source category. However, the BACT analyses did not consider the experience in the waste-to-energy source category in determining BACT for mercury for TGC. Technology transfer refers to a control technology being applied at source categories other than the source under consideration. Jt. #9 at B.11. Waste-to-energy plants, or incinerators, are similar to coal-fired power plants because the emissions are similar and the same technologies can be used to control mercury emissions from both. 12-2-03 TE at 47:8-18, 54: 2-11; 6-1-04 TE at 27:2-34:21 (Fox). Carbon injection systems have been used to control mercury at these facilities for two decades, PR279, p 31, achieving 95 to 98% mercury control. PR280, p 4-8; PR281, p 16. TGC's vendor, ALSTOM, concluded that this experience is relevant and adds considerably to the confidence in the concept of PAC (powdered activated carbon) injection for mercury control on coal-fired boilers. P123-131, p.1 (Abstract), 9 (Conclusions). ALSTOM currently offers a carbon injection system for coal-fired power plants based on two decades of experience. PR279, p 31; 6-1-04 TE at 33:13-34:21 (Fox). Massachusetts relied on incineration systems to support its decision to

regulate mercury emissions from coal-fired power plants. PR281, p 16; 6-1-04 TE at 35:5-20 (Fox). Black & Veatch relied on this experience to conclude in the Air Quality Control System Performance Matrix, P137-7, that carbon injection was available for TGC.

612. *Fabric filters* –Petitioners point out that fabric filters were considered to be feasible for TGS until September 2002, when a white paper was produced after the close of public comments, raising new issues that had not previously been discussed. Jt. #17, at Red 147-148. Indeed, the SOB and final response to comments contain no evidence that the Cabinet reviewed this white paper before issuing the final permit. Jt. #7, p 17-25; Jt. #63.

613. Although TGC concluded in its February and October 2001 applications that BACT for PM/PM_{10}, beryllium, and mercury was a baghouse (i.e. fabric filter), TGC concluded in the May 2002 Addendum that BACT for PM/PM_{10} was an electrostatic precipitator. Jt. #33, p. 23. A new section was added to the BACT analysis to address beryllium and mercury that did not explain why fabric filters were no longer BACT for these pollutants.

614. Petitioners urge that TGC did not follow the very passage from the NSR Manual which it cited, at Jt. #61, p. 4-4 and Jt. #57, p. 4-4, which states that in eliminating technologies which are infeasible the demonstration of technical infeasibility should be clearly documented and the technical infeasibility should be based on physical, chemical and engineering principles. Instead, the white paper states that it is questionable if satisfactory long-term performance of a fabric filter on a high-sulfur coal-fired unit can be maintained, Jt. #17 at Red 147, because of concerns, including acid attack, fouling and solids buildup on the bags. There was no analysis that these problems would occur for the TGC facility, and indeed, three vendors bid fabric filters for TGS. Also, all of these concerns would normally be addressed in a cost analysis, and are not reasons for eliminating a technology as infeasible in Step 2 of the top-down BACT analysis.

These issues can be addressed by selecting bags that are corrosion resistant, by using reheat to keep the temperatures above the acid dew point, by selecting materials of construction that are resistant to corrosion, and/or by altering the location of the baghouse. These measures increase the cost. P137-61, p 14 (Black and Veatch analysis); 6-1-04 TE at 231:19-235:19 (Fox). Dr. Fox states that in order to use a baghouse in a high sulfur environment, material would need to be selected that was able to withstand the high levels of sulfur; in other words, corrosion resistant metals would have to be used in constructing the frame. Bags would need to be selected that would hold up under the high sulfur environment in the baghouse, which would be considered in a BACT analysis in the cost-effectiveness analysis, but should not be used to eliminate baghouses from consideration. Indeed, Lillestolen testified that acid-resistant bags, Gortex or Teflon, could be used to address bag corrosion and corrosion-resistant materials could be used to eliminate corrosion of fabric filter components. 3-16-04 TE at 166:10-167:18. He further admitted that the dew point issue could be addressed by keeping the temperature above the acid dew point temperature, e.g., by reheat. 3-16-04 TE at 166:10-172. Shepherd was in agreement that with respect to sulfuric acid attack on a baghouse, "I didn't really see that that was that serious because virtually – well, if you keep the baghouse above the acid dewpoint, that shouldn't be a problem." P160 at 113:20-23. No fabric filter cost analysis was submitted to DAQ. P160 at 27:19-28:6 (Shepherd).

615. The SOB, Jt. #7, offers no explanation for switching from fabric filters to ESP/WESP as BACT for mercury and HAP control. Indeed, a preponderance of the evidence shows that fabric filters remove more of the mercury and beryllium than electrostatic precipitators. The following sources have concluded that fabric filters remove 90% of the mercury while ESPs remove 9% (cold-side ESPs) to 36% (hot-side ESPs). Jt. #12, v. 1 (April

2002 EPA Report on Control of Mercury Emissions from Coal-Fired Utility Boilers, Table 6-5); P121-65A, Table ES-1; P120-58: PR 279, p 30; PR281, p 12, Table 1. A hot-side ESP is located before the air preheater, where the gases are hottest, and a cold-side ESP is located after the air preheater, where the gases are cooler. The TGS ESP is after the air preheater. 3-16-04 TE at 58:5-22; 169: 25-170:10; 170:23-171:1 (Lillestolen). Thus, TGS will use a cold-side ESP, the worst-case for mercury control. Dr. Lindau, who was on the ALSTOM proposal team for TGC, wrote a paper stating that "(i)t can be seen that fabric filters enhance the capture of mercury more than ESPs. This is because in the filter cake there is intimate contact between the vapour phase mercury and the solid materials such as fly ash and LOI (loss-on-ignition) carbon". PR279, p 30; see also 3-16-03 TE at 140:24 – 141:1.

616. Lillestolen testified that "as an absorption device, whether it be for mercury, sulfur dioxide or any other acid gases, that the fabric filter is a much better device for enhanced absorption as compared to an ESP." 3-16-04 TE at 138:16-23. Burns & McDonnell, TGC's engineer, compared mercury removal by fabric filters and ESPs and concluded that "in general, it can be seen that the mercury removal capability of existing ESPs typically does not even reach the 50% control level," noting one exception that was equipped with an SNCR (Selective Non-Catalytic Reduction), a technology not used by TGC. Fabric filters, on the other hand, achieved 85% mercury control. P120-58 p 6-8. Compare Figures 1 and 2. Fabric filters also remove more of the beryllium and most other hazardous air pollutants (HAPs) associated with particulate matter than ESPs. A presentation by Bill Maxwell, whom Adams claims he consulted to determine mercury MACT, shows that the median removal of beryllium by ESPs was greater than 92% while the median removal by fabric filters was greater than 95%. Jt. #12, Non-mercury HAP, March 4, 2002. A memorandum summarizing non-mercury HAP data noted poor HAP removals

were limited to sites with either an FGD (Flue Gas Desulfurization) or a cold-side ESP, the controls selected for TGS. Jt. #12, Memorandum from Martha Keating to Environmental Caucus of MACT Work Group, Bill O'Sullivan, and John Paul, RE: Non-Hg HAPs Analysis, May 28, 2002.

617. Although TGC urges that "(m)ercury removal mechanisms are not well understood", Lillestolen testified that ALSTOM had a proprietary prediction model and database based on long-term mercury testing that allowed them to make 90% control guarantees for specific plants. 3-16-04 TE at 128:24 – 129:6; 132:12-18: 132:24–133:1. The database was available before the permit was issued, although commercial guarantees were not available until after. However, Petitioners point out that the 80% mercury control proposed for TGS is also not based on a guarantee, but instead is an estimate. 3-16-04 TE 139:16-18 (Lillestolen). To address uncertainty and determine how a given coal would perform, tests are conducted to develop design criteria. Donau Carbon, which had carbon injection systems in operation on coal-fired boilers since 1996, stated that before issuing a guarantee for TGS, it would require a test which would involve a sample of coal being burned in a laboratory or bench-scale pilot combustor to generate flue gases, which are then treated with carbon, simulating the actual process. 6-2-04 TE at 174:4-7 (Fox). They were never asked by TGC.

618. Petitioners urge that TGC's mercury BACT does not evaluate the gaseous or elemental form of mercury. There are three forms of mercury – elemental or gaseous, particulate and oxidized. Although TGC states that ESPs and baghouses do not remove elemental mercury, fabric filters do. Jt. #12, v. 1 (April 2002 EPA Report, p 6-7); PR279, p 30. Also, although TGC argues that there are no commercially available control technologies for gaseous mercury, SCR converts elemental mercury to oxidized mercury, which can then be removed by the downstream

wet FGD. P121-69; TGC42 (SCR listed as controlling mercury); 11-20-03 TE at 51:11-16 (Fox); 4-12-04 TE 36:8 – 37:2 (Adams). A more efficient SCR would have improved mercury removal, which was not evaluated in the mercury or other HAP BACT analyses. Activated carbon also removes elemental mercury, and carbon injection was commercially available when TGS was permitted. See Count 10 – MACT.

619. The mercury BACT analysis does not explain how gaseous or elemental mercury would be controlled, although the January 2002 ALSTOM letter demonstrates that a significant fraction of the mercury for all technology combinations for bituminous coal-fired units is in the elemental form. Jt. #44, at Red 100. The mercury BACT analysis did not discuss this form of mercury at all.

Conclusions on BACT for Mercury and Beryllium

620. Again, both the Cabinet and TGC stated repeatedly that they followed a top-down analysis based on the NSR Manual. "Although the top-down approach is not mandated by the Act, if a state purports to follow this method, it should do so in a reasoned and justified manner." Alaska v. US EPA, 298 F.3d 814, 822 (9th Cir. 2002). A technology is "available" under a top-down analysis based on the NSR Manual if there is a "realistic potential" that it can be used. Under this analysis, carbon injection should have been evaluated because it has been used in the waste-to-energy plants and in European plants.

621. With regard to the fabric filters, which were considered to be feasible for TGS until shortly before the permit issuance, TGC did not follow the technical infeasibility demonstration set out in the NSR Manual, but instead made conclusory comments in the white paper, Jt. #17, such as questioning if long-term performance on high sulfur coals could be maintained. TGC performed no analysis on whether the concerns (acid attack, fouling and solids

buildup on the bags) would occur at TGS. Indeed, these concerns should be addressed in a cost analysis, not technical feasibility analysis. No cost analysis was submitted to DAQ. The SOB, Jt. #7, offers no explanation for the change from fabric filters to ESP/WESP in spite of considerable evidence showing that fabric filters remove a greater percentage of mercury than ESPs.

622. It was erroneous for DAQ to make a BACT determination based on TGC's elimination of carbon injection and fabric filters without the required technical feasibility analysis. Hence, the permit should be remanded for a new BACT determination on mercury and beryllium.

H. BACT for Material Handling Units and Auxiliary Boiler

623. Petitioners contend that even though the permit purports to contain BACT limits for the material handling units and auxiliary boiler, these limits were arbitrarily set.

624. TGC maintains that the top technologies were selected for the material handling units and routinely used at plants to comply with BACT. Jt. #61 at Red 35-36; Jt. #57 at Red 35-36; Jt. #33 at Red 32-24; Jt. #7 at 23. 4-14-04 TE at 180-81 (Adams). Also, TGC urges that top technology was selected for the auxiliary boiler - operational controls as well as limits for specific pollutants (low-NO_x burners and low-sulfur fuel (0.05% sulfur)) with proper operation as BACT, and Petitioners fail to offer any alternatives DAQ should have considered. Jt. #8 at 15-16; Jt. #7 at 24; 4-14-04 TE at 33 (Adams).

625. The Cabinet states that the facility design, as well as the precautions to minimize coal-handling dust, and the limit on operating hours and low sulfur fuel for the auxiliary boiler are BACT.

626. I agree with Respondents that Petitioners have failed to carry their burden of proof on this issue.

General Conclusions on Count 9

627. TGC states in its post hearing brief that "there is no regulatory requirement that a BACT determination be based on a top-down analysis", citing the U.S. Supreme Court's recent decision in Alaska Dept. of Envtl. Conserv. v EPA[60], 124 S.Ct. 983 (2004) at 995, n. 7. The

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[60] The factual history of the 2002 Ninth Circuit Alaska case and the U.S. Supreme Court review, which concern the authority of the EPA to enforce the provisions of the CAA's PSD program, is as follows. In 1996, Cominco, operator of a zinc concentrate mine in northwest Alaska, initiated a project to expand zinc production by 40%. Cominco applied to the Alaska Department of Environmental Conservation (ADEC) to allow increased electricity generation by its standby generator, MG-5. ADEC initially proposed as BACT for the MG-5 the emission control technology known as selective catalytic reduction (SCR), which reduces nitrogen oxide emissions by 90%. In response, Cominco amended its application to add a seventh generator, MG-17, and to propose as BACT an alternative control technology – Low NO_x – that achieves a 30% reduction in nitrogen oxide pollutants. ADEC in conjunction with Cominco issued a first draft PSD permit and preliminary technical analysis report that concluded Low NO_x was BACT for MG-5 and MG-17. To determine BACT, ADEC employed EPA's recommended top-down methodology. Despite its staff's clear view that SCR was technologically, environmentally, and economically feasible for the power plant engines, ADEC endorsed the alternative proferred by Cominco. To achieve nitrogen oxide emission reductions commensurate with SCR's 90% impact, Cominco proposed fitting the new generator MG-17 and the six existing generators with Low NO_x. Cominco asserted that it could lower net emissions by 396 tons per year if it fitted all seven generators with Low NO_x rather than fitting two (MG-5 and MG-17) with SCR and choosing one of them as the standby unit. Cominco's proposal hinged on the assumption that under typical operating conditions one or more engines will not be running due to maintenance of standby-generation capacity. If all seven generators ran continuously, however, Cominco's alternative would increase emissions by 79 tons per year. Accepting Cominco's submission, ADEC stated that Cominco's Low NO_x solution "achieved a similar maximum NO_x reduction as the most stringent controls; could potentially result in a greater NO_x reduction; and is logistically and economically less onerous to Cominco".

NPS submitted comments to ADEC objecting to the projected offset of new emissions from MG-5 and MG-17 against emissions from other existing generators that were not subject to BACT. Such an offset, NPS commented, is neither allowed by BACT, nor achieves the degree of reduction that would result if all the generators that are subject to BACT were equipped with SCR. NPS further observed that the proposed production-increase project would remove operating restrictions that the 1994 PSD permit had placed on four of the existing generators. Due to that alteration, NPS urged, those generators, too, became part of the production-expansion project and would be subject to the BACT requirement. EPA wrote to ADEC stating that although ADEC states that the most stringent level of control is economically and technologically feasible, ADEC did not propose to require SCR. Once it is determined that an emission unit is subject to BACT, the PSD program does not allow the imposition of a limit that is less stringent than BACT. EPA agreed with NPS that based on the existing information, BACT would be required for MG-1, MG-3, MG-4 and MG-5. After receiving EPA comments, ADEC issued a second draft PSD permit and technical analysis again finding Low NO_x to be BACT for MG-17. ADEC agreed with NPS and EPA that emission reductions from sources that were not part of the permit action (MG-1, 2, 3, 4, 5, and 6) could not be considered in determining BACT for MG-17. Contradicting its May 1999 conclusion that SCR was technically and economically feasible, ADEC found in September 1999 that SCR imposed a disproportionate cost on the mine. ADEC concluded that requiring SCR for a rural Alaska utility would lead to a 20% price increase, and in comparison with other BACT technologies, SCR came at a significantly higher cost. No economic basis for a comparison between the mine and a rural utility appeared in ADEC's technical analysis.

EPA protested the revised permit stating that Cominco had not adequately demonstrated any site-specific factors to support their claim that the installation of SCR is economically infeasible at the mine. Therefore, elimination of SCR as BACT based on cost-effectiveness grounds is not supported by the record and is clearly erroneous. To justify the 1999 permit, EPA suggested that ADEC could include an analysis of whether requiring Cominco to install and operate SCR would have any adverse economic impacts upon Cominco specifically. Cominco said such an inquiry was unnecessary and expressed concerns related to confidentiality; it declined to submit financial data. Cominco simply stated that the company's overall debt remains quite high. Cominco also invoked the need for industrial development in rural Alaska.

In December 10, 1999, ADEC issued the final permit and technical analysis report. Once, again, ADEC approved Low NO_x as BACT for MG-17 to support Cominco's mine project and its contributions to the region. ADEC did not include the economic analysis EPA had suggested, and advanced, as cause for its decision, SCR's adverse effect on the mine's unique and continuing impact on the economic diversity of the region and on the venture's world competitiveness.

On the same day, EPA issued an order to ADEC, prohibiting ADEC from issuing a PSD permit to Cominco unless ADEC satisfactorily documented why SCR is not BACT for the Wartsila diesel generator, MG-17. EPA stated that ADEC's own analysis supports the determination that BACT is SCR and that ADEC's decision in the proposed permit therefore is both arbitrary and erroneous.

On February 8, 2000, EPA issued a second order prohibiting Cominco from beginning construction or modification activities at the mine. A third order, issued on March 7, 2000, superseding and vacating the February 8 order, generally prohibited Cominco from acting on ADEC's PSD permit but allowed limited summer construction. On April 25, 2000, EPA withdrew its December 10 order. On July 16, 2003, ADEC granted Cominco a PSD permit to construct MG-17 with SCR as BACT. Under the July 16 permit, SCR ceases to be BACT if and when the case pending before the U.S. Supreme Court is decided in favor of the state of Alaska.

When EPA issued its first order against Cominco, February 8, 2000, ADEC and Cominco petitioned the Court of Appeals for the Ninth Circuit for review of EPA's orders. The Court of Appeals resolved the merits in a judgment released July 30, 2002. 298 F.3d 814. It held EPA had authority to issue the contested orders and had properly exercised its discretion in doing so.

The U.S. Supreme Court affirmed the Ninth Circuit in a holding that the CAA authorizes EPA to stop construction of a major pollutant emitting facility permitted by a state authority when EPA finds that an authority's BACT determination is unreasonable in light of 42 U.S.C. Section 7479(3)'s prescribed guides. The Court noted that the permitting authority exercises primary or initial responsibility for identifying BACT in line with the Acts definition of that term. States have only authority to make reasonable BACT determinations with fidelity to the Act's purpose. EPA asserts only the authority to guard against unreasonable designations. EPA acknowledges the need to accord appropriate deference to states' BACT designations and disclaims any intention to second guess state decisions. Only when a state agency's BACT determination is not based on a reasoned analysis may EPA step in to ensure that the statutory requirements are honored. EPA is authorized to act in the unusual case in which a state permitting authority has determined BACT arbitrarily.

Even if the EPA can issue a stop construction order when a state agency unreasonably determines BACT, the Court next addresses whether EPA acted impermissibly in this instance. The Court was satisfied that EPA did not act arbitrarily in finding that ADEC furnished no tenable accounting for its determination that Low NO_x was BACT for MG-17. The Court considers whether EPA's actions were arbitrary, capricious and an abuse of discretion or otherwise not in accord with the law. ADEC's switch from finding SCR economically feasible in May 1999 to finding SCR economically infeasible in September 1999 had no factual basis in the record. No record evidence suggests that the mine, were it to use SCR for its new generator, would be obliged to cut personnel, or raise zinc prices. Absent evidence of that order, ADEC lacked cause for selecting Low NO_x as BACT based on the more stringent control's impact on the mine's operation or competitiveness. ADEC's basis for selecting Low NO_x thus reduces to a readiness to support Cominco's mine increase project and its contributions to the region. This justification hardly meets ADEC's own standard of a source specific economic impact which demonstrates SCR to be inappropriate as BACT.

Court notes in the same footnote that "EPA represents that permitting authorities 'commonly' use top-down methodology." In the Ninth Circuit Court of Appeals' 2002 decision (298 F. 3d 814), which led to the 2004 Supreme Court decision affirming, the court stated that "(a)lthough the top-down approach is not mandated by the Act, if a state purports to follow this method, it should do so in a reasoned and justified manner." Id. at 822.

628. As stated earlier in this Report, during the formal hearing TGC moved to exclude evidence pertaining to the NSR Manual and for a ruling that the Manual was not binding on DAQ. I issued an order during the formal hearing granting TGC's motion for a ruling that the NSR Manual is not a binding legal requirement on DAQ because it has not been incorporated into the regulations. Docket #249. My order also reflects that the parties acknowledge that the Manual is relevant guidance information and is appropriate for use by DAQ.

629. TGC repeatedly stated in its submissions that it was following the NSR Manual. DAQ acknowledges this and cites to the Manual in its explanation of BACT limits. As stated in Alaska, when a state purports to follow the method outlined in the Manual, it must do so in a reasoned and justified manner. This is, of course, true for the applicant as well. Adams noted that TGC "proceeded not to follow it (the NSR Manual) to a large degree." 4-22-04 TE at 74:13-14. "My criticism is that the applicant didn't do a good job of following the NSR Manual." Id. at 74:20-21 (Adams).

630. As confirmed by Dr. Fox, DAQ lacks the resources to perform the kind of review required for a project as large and complex as TGS. Peabody Coal, however, which is the largest coal company in the world, has the resources and obligation to do the research and develop the

information which would then enable DAQ to perform its BACT determination in a reasoned and justified manner.

631. I agree with Petitioners that instead of performing the top-down BACT analysis described in the NSR Manual, as TGC states it did, TGC instead determined the limits based on vendor quotes and then invented a top-down analysis to fit the technology it decided to buy. Petitioners presented extensive evidence on control technologies which was not considered by TGC, and in addition, presented documents from KEC and TGC files showing more effective control technologies, which were available, but were not included in the BACT analyses submitted to DAQ.

632. TGC never advised the Cabinet that on April 13, 2001, Peabody proposed to use an "advanced technology envelope" on one of its two 750 MW units. P137-53, p. TB7801-7803. The project was called the Thoroughbred Ultra Low Emissions Project (TULEP). The only difference between the technology that was permitted for TGS and that proposed in the TULEP project is that the baghouse proposed in TULEP was replaced with an electrostatic precipitator (ESP). The difference in the emission rates and degree of reduction proposed for TULEP compared to BACT limits in TGC's final permit is as follows:

	TGC BACT Levels		**TULEP** **Ex. P137-53**	
Pollutant	**Emission** **Rate**	**Degree** **Of**	**Emission** **Rate**	**Degree** **Of**

	(lb/MMbtu)	Reduction (%)	(lb/MMbtu)	Reduction (%)
NO_x	0.08	55.6	0.016	95
SO_2	0.167	98	0.038	99.5
Hg	13.21E-5	80	1.18E-5	90

633. TGC did not present testimony from Black and Veatch or Burns and McDonnell, the engineering firms on the project, but instead chose only to present evidence from the technology vendor chosen, ALSTOM.

634. TGC's BACT analyses do not include analyses of energy, environmental, economic, or cost impacts for any emission source or pollutant except CO and VOC emissions from the PC boilers and coal washing. There are no costs analyses for NO_x, PM_{10}, SO_2, mercury or beryllium emissions from the PC boilers.

635. In addition, the level of detail provided by TGC is not adequate to support its conclusions. The Cabinet now requests that applicants supply the information missing from the TGC record. The Cash Creek application, also prepared by KEC, is similar to the BACT analysis KEC prepared for TGC. Compare PR305 and PR346, Sec. 4.0 to Jt. #33, Sec. 4.0. See notice of deficiency letter dated January 22, 2004, for Cash Creek.

636. In January 2004, the Cabinet issued a notice of deficiency for Cash Creek, whose BACT analysis was prepared by KEC, the firm which had prepared TGC's. The Cabinet wrote:

> 3. The Best Available Control Technology (BACT) analysis is cursory and unacceptable at this time. Justification must be made for the selection of emission limits and control technology, not just a selection without justification of an emission level higher than previous regulatory determinations. A variety of permits and application (sic) have higher control efficiencies than submitted in

> the application. Previous regulatory agency determinations are the presumptive floor for a BACT determination. A detailed Top-Down BACT analysis must include detailed lists of all available control technology and should follow the process outlined in Chapter B of the New Source Review Workshop Manual. The analysis must include control specific information for each item listed in STEP 3 of Table B-1 (attached) of the manual in a format similar to Table B-3 (attached). The analysis must include an appropriate economic analysis for all recent technologies that could be applied to boilers.
> …
>
> 7. The application fails in most cases to properly state the basis for BACT, instead listing BACT as an emission rate per unit of heat input. BACT is the maximum degree of reduction for each pollutant subject to regulation under 42 USC 7401 to 7671 Q (Clean Air Act). The application should state the control efficiency of each pollution control train.
> PR237, p. 2-3, items 3, 8 & 11 and Table B-1.

637. In the Cash Creek notice of deficiency letter DAQ acknowledges the deficiencies which are present in TGC's applications and were never cured. DAQ also acknowledges that when an applicant purports to follow the NSR Manual it cannot pay lip service to the Manual by picking and choosing the portions which suit its purposes, but instead must accurately adhere to it.

<u>Count 10 – Maximum Achievable Control Technology (MACT)</u>

Count 10 - Findings

Overview

638. As a new major source of hazardous air pollutants (HAPs), TGC is subject to the requirement that it apply the maximum achievable control technology (MACT) for its HAP emissions.

639. Section 112(n) of the CAA was enacted in 1990 and required EPA to collect data on mercury emissions for power plants and assess risks to public health from these emissions. In December 2000, EPA determined that, based on the potential and adverse effects of mercury,

HAPs emitted from steam electric generating units should be regulated. 65 Fed. Reg. 79825 (Dec. 20, 2000). EPA's finding triggered a rulemaking to establish an industry-wide MACT standard.

640. In January 2004, following issuance of the TGC permit and during the course of the formal hearing in this case, EPA issued "Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units" (TGCR258 – 69 Fed. Reg. 4652) and in March 2004, EPA issued a "Supplemental Notice" (CabR24 – 69 Fed. Reg. 12398). In the proposed rule, three alternative regulatory approaches are proposed – 1) EPA proposed to retain the December 2000 finding and associated listing of coal- and oil-fired utility units and to issue MACT national emission standards for hazardous air pollutants for such units; 2) EPA proposed revising its December 2000 finding, removing coal- and oil-fired utility units from the CAA, section 112(c) list and issuing final standards of performance under section 111 for new and existing coal-fired units that emit Hg and new and existing oil-fired units that emit nickel; and 3) EPA proposed retaining the December 2000 finding and regulating Hg emissions from utility units under section 112(n)(1(A). In the Supplemental Notice, EPA proposed additional regulatory text, which largely governed the proposed section 111 standards of performance for Hg, and included a cap-and-trade rule for Hg emissions from coal-fired utility units. The Supplemental Notice also proposed state plan approvability criteria and a model cap-and-trade program.

641. In the Supplemental Notice, CabR24 at 12403, EPA states that 90% mercury removal is not currently achievable. In a section entitled "The Timing of Technology Development and Commercialization", Id., EPA states that some Hg emissions control

technologies such as sorbent injection, with 50 to 70% Hg emissions reduction, will be ready for "broader full-scale demonstration on bituminous coal in 2005…. (i)f these demonstrations are successful, commercial deployment could occur on a large scale after 2010, or perhaps later. Assuming two years to permit and construct such commercial units, large scale operation of the technology is feasible by 2013 and 2015…. A second wave of technologies operating at 90% reduction should be ready for full-scale demonstration by 2010, leading to effective reductions after 2018…. Substantial progress in Hg control technology has been achieved through a partnership between government … and industry. A broad portfolio of technologies is beginning to emerge, and EPA is confident these techologies will most likely be able to provide 50 to 70% reduction of Hg emissions in the period after 2015, with up to 90% reduction of hg emissions on many applications after 2018. Thus, EPA is proposing a Phase II cap of 15 tons in this supplemental notice, which will take full advantage of the emerging, demonstrated technologies that are outlined above." Id.

642. However, TGC was subject to a case-by-case MACT determination because at the time the TGC permit was issued a national MACT standard for steam electric generating units had not been promulgated. TGS will be required to meet the more stringent of either its permit limit or EPA's final rule limit[61]. TGC was one of the first steam electric generating facilities subject to a case-by-case MACT determination and was one of the very early case-by-case

[61] I take judicial notice that EPA finalized the Clean Air Mercury Rule (CAMR) on May 18, 2005. 70 Fed. Reg. 28606. The effective date of the final rule is July 18, 2005. The CAMR establishes standards of performance for mercury for new and existing coal-fired electric utility steam generating units, as defined in CAA section 111. The amendments to CAA section 111 rules would establish a mechanism by which Hg emissions from new and existing coal-fired utility units are capped at specified, nation-wide levels. A first phase cap of 38 tpy becomes effective in 2010 and a second phase cap of 15 tpy becomes effective in 2018. Facilities must demonstrate compliance with the standard by holding one "allowance" for each ounce of Hg emitted in any given year. Allowances are readily transferable among all regulated facilities. See also www.epa.gov/mercuryrule .

MACT permits which DAQ had done. Adams referred to case-by-case MACT as a "hellish program" to ask the states to do in terms of hours spent – with EPA looking over DAQ's every number and every limit.

643. A case-by-case MACT analysis is similar to a case-by-case BACT analysis but differs in some major respects because the definition of MACT is distinct from the definition of BACT. MACT like BACT is an emission limit, or if an emission limit is not feasible or enforceable, a work practice. 40 CFR Section 63.43(d)(3).

644. The mercury MACT emission limit in the permit is 0.1047 tons per unit per year, Jt. #8, p 4, Sec. B.2.m., or 3.21E-06 lb/MMbtu, Jt. #33 at Red 21, Table 4.2-1, "Hg, 30-day" column. This limit was calculated assuming 0.16 ppm mercury in the coal and a removal efficiency of 80%. P171. The control technologies are low NO_x burners, SCR, ESP, WFGD, and WESP.

645. The only MACT determination for non-mercury HAPs in the permit requires that lead be reduced by 80% and all other non-mercury metallic HAPs by 98%. Jt. #33 at Red 80-85; Jt. #8 at 14; 12-2-03 TE at 136:20-137:11 and 138:8-13 (Fox).[62] The permit contains a MACT limit on VOC(HAPs) of 5.154 tons per year per unit. Jt. #8, pg 4.

646. Petitioners urge that the mercury MACT limit was not determined pursuant to the criteria dictated by the definition of MACT in 40 CFR 63.41, incorporated into Kentucky regulations at 401 KAR 63:105, Section 2. Specifically, they contend that DAQ never made a proper MACT floor finding. Thus, they urge that the MACT determination made by DAQ was

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[62] Petitioners point out that the permit does not support TGC's assertion in its post hearing brief that "DAQ determined based on its evaluation that MACT is limits (sic) based on 98% reduction in acid gas emissions, 99.5% reduction for non-mercury metallic HAPs, and a VOC HAP limit of 5.154 tons per year per each unit." Petitioners

arbitrary and capricious. In addition, they argue that no MACT analysis was performed to develop the permit limits for the non-mercury HAPs.

647. TGC urges that DAQ critically evaluated the best information available, in close coordination with EPA Region 4 and EPA's MACT development work group, and arrived at a MACT determination which has a rational basis.

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further point out that the 99.5% reduction claim appears in the record for the first time as an attachment to TGC's prehearing memo, filed in October 2002.

648. The Cabinet argues that Petitioners' reliance on inadequacies in the application is misplaced because it is DAQ's determination which is at issue, not the application. The Cabinet maintains that DAQ justifiably relied on the expertise of EPA with regard to MACT for electric generating units.

General Findings

649. Section 112(g) of the Clean Air Act, 42 U.S.C. Section 7412(g)(2)(B), states:

> (**N)o person may construct** or reconstruct any **major source of hazardous air pollutants, unless** the Administrator (or the State) determines that the **maximum achievable control technology emission limitation** under this section for new sources **will be met**. Such **determination shall be made on a case-by-case basis where no applicable emission limitations have been established** by the Administrator. (Emphasis added).

650. MACT is defined in 40 CFR Section 63.41 (incorporated into Kentucky regulations at 401 KAR 63:105, Section 2) as:

> Maximum achievable control technology (MACT) emission limitation for new sources means **the emission limitation which is not less stringent than the emission limitation achieved in practice by the best controlled <u>similar source,</u> and which reflects the maximum degree of reduction in emissions** that the permitting authority, taking into consideration the cost of achieving such emission reduction, and any non-air quality health and environmental impacts and energy requirements, determines is achievable by the constructed or reconstructed major source. (Emphasis added).

Similar source is defined as:

> **A similar source** means a stationary source or process that **has comparable emissions and is structurally similar in design and capacity to a constructed** or reconstructed **major source such that the source could be controlled using the same control technology**. 40 CFR 63.41, incorporated by reference at 401 KAR 63:105, Section 2(1). (Emphasis added).

651. There is EPA guidance relating to how to do a case-by-case MACT analysis. MACT Determinations Under Section 112(g), dated May 1994, report no. EPA 453/R-94-026. 11-14-03 TE 72-83 (Fox). In a case-by-case MACT analysis, the first step is referred to as Tier 1. In Tier 1, the best-controlled similar source is identified. The best-controlled similar source is the "MACT floor". The final emission limit must be at least as stringent as the MACT floor. If a best-controlled similar source cannot be identified, i.e. if there is no MACT floor (a negative MACT floor finding), then you move to Tier 2. Tier 2 is similar to the top-down BACT process. In the third and last step, Tier 3, an emission limit is established based on either the best-controlled similar source identified in Tier 1 or the results of the Tier 2 analysis. See PD153-20, which is a flow chart from the EPA published guidance document. Once the MACT floor is determined, TGC could select any method, pollution control train, coal washing, or coal blending to meet it since the definition of MACT requires the maximum degree of reduction achievable for that source, considering the allowable factors.

652. When deciding what a similar source is when trying to establish whether there is a best-controlled similar source, there are two questions to answer. The first question is whether the two emission units have similar emission types. The second is whether the same control technologies can be applied. See PD153-21, which is p 45 from PD153-20. To the first question, i.e. defining what is a similar source to TGS, Dr. Fox would define similar sources as all coal-fired boilers firing coal or segregate it by saying all coal-fired boilers firing bituminous coal. The answer to the second question (can the emission units be controlled with the same type of control technology) is yes for all coal-fired boilers. In other words, the same control trains and same HAP-specific control methods can be used, irrespective of the type of coal being

burned. Although there are differences in cost and differences in types of designs, the same type of control technology can be applied to any coal-fired boiler. 11-14-03 TE at 88 (Fox).

653. EPA did a three-phase study under Section 112 of the CAA to establish a mercury MACT standard for the electric generating segment. This is referred to as the ICR (Information Collection Request) Database. EPA started out by sending the universe of coal-fired power plants a questionnaire asking for information on pollution control train and coal type. In Phase I of the study, information was collected on the fuels, boiler types, and air pollution control devices used at all coal-fired utility boilers in the U.S. In Phase II, coal data were collected and analyzed for 1,043 coal-fired boilers and three IGCC units. Over 39,000 samples of coal were analyzed for mercury, chlorine, sulfur, ash, moisture, and heat content. In Phase III, the inlet and outlet concentrations of 81 of these units were measured. The tested units were selected at random to achieve 95% confidence in the results. Jt. #12, v. 1, April 2002 EPA Study; P121-65A; 11-14-03 TE at 100:18 – 102:16 (Fox); P120-58.

654. While TGC acknowledges that the ICR Database is the best information available, it has some limitations, i.e. short-term emissions that do not account for fuel variability or achievable mercury removal and negative removal rates.

655. TGC's MACT analyses can be found in six locations in the record:

1) the October 2001 Revised Application (Jt. #57 at Red 19-21);

2) the December 12, 2001 Response to Comments (Jt. #56 at Red 41-44);

3) the December 21, 2001 Case-By-Case MACT analysis (Jt. #55);

4) the January 2, 2002 supporting information (Jt. #54);

5) the March 10, 2002 Responses to Comments (Jt. #44); and
6) the May 29, 2002 Addendum to the October 2001 Application (Jt. #33, Addendum 2).

656. TGS's original application was submitted in February 2001, two months after EPA's determination to regulate HAPs from steam electric generating units. Thus, TGS was one of the first steam electric generating facilities subject to a case-by-case MACT determination. 4-14-04 TE at 48-49 (Adams); 3-4-04 TE at 161 (Tickner); 4-15-04 at 23-24 (Handy). In its application, TGC acknowledged the requirement for a case-by-case MACT analysis, but stated that because EPA had indicated that guidance for establishing a case-by-case MACT determination will not be made available until mid 2001, no case-by-case MACT was included in this original application. Jt. #61 at Red 17.

657. The October 2001 application stated that the "(o)verall mercury removal from the facility is estimated to be greater than 80 percent with possible removals in excess of 90 percent". 5-3-04 TE at 241-42 (Handy); Jt. #57 at Red 21.

658. On December 21, 2001, in response to a request from EPA and DAQ, TGC submitted a stand-alone document summarizing its case-by-case MACT analysis. This document concludes that a work practice standard requiring the operation of certain control equipment - low NO_x burners, SCR, particulate control, wet FGD, and WESP - should be accepted as the best available means of controlling HAP emissions including mercury, rather than a numeric emission limit. The reasons TGC gives for the work practice standard are because of outstanding questions referenced in the introduction of the document, including EPA's lack of long-term monitoring data. Jt. #55.

659. On January 2, 2002, TGC submitted supporting information for its December 21 analysis. Jt. #54. Included was a letter from ALSTOM explaining the removal efficiencies expected from the proposed control technologies at TGS – the low NO_x burners, an SCR, an ESP, a Wet FGD, and a WESP. Id. at Red 12-13. ALSTOM stated that the combination of

technologies proposed for TGS represented the best air quality control technology for mercury available for TGS, with an estimated mercury removal in the range of 85%. However, allowing for contingencies, ALSTOM stated that it would be prudent to estimate an 80% removal. Id.

660. Included with the ALSTOM letter, at Red 14-15, is a chart entitled Mercury Removal and Stack Gas Speciation from Pulverized Coal Boilers Using Existing Control Technology. The chart is ALSTOM's summary of EPA's ICR database in which it categorizes the results of the tests according to coal type and pollution control train.

661. The portion of the chart most similar to TGC is the "Technology Combinations for Bituminous Coals". For bituminous coals, the chart indicates the best performing single source, using technology combinations, is the one using a spray dryer adsorber and fabric filter with an average removal efficiency of 98%. The next best is a facility equipped with a fabric filter and flue gas desulfurization (FGD) system, which achieved 97% mercury removal. Neither of these two technologies were evaluated by TGC in the course of performing their MACT analyses as a best-controlled similar source. Although vendors did make proposals on similar pollution control trains, TGC did not pick those proposals.

662. In a search for a "best controlled similar source," DAQ determined that eastern bituminous pulverized coal boilers are similar sources for purposes of MACT. 2-9-04 TE at 88:15 – 89:5 (Adams). DAQ also requested TGC to compare the proposed control efficiency for mercury to a similar existing source. 5-3-04 TE at 245 (Handy).

663. Tom Adams and Ben Markin had the most extensive involvement with the case-by-case MACT determinations for TGC. "Achieved in practice" under the definition of MACT means to Adams "a technology that is functioning, that is in use, in operation on the best – the same class of source …(t)he basic bar is a source that is in operation or that is permitted." 4-16-

04 TE at 45-46. … "the permitting agency has to determine that a technology is available, achievable, and appropriate for a similar controlled source." Id. at 47.

664. Using a software tool created by EPA to assist permitting authorities in making case-by-case MACT decisions, TGC predicted a theoretical mercury removal percentage for the D.B. Wilson facility in Kentucky and compared this to the proposed removal for TGS. 5-4-04 TE at 8-10 (Handy). TGC maintains that the D.B. Wilson facility was selected because it burned a similar high-sulfur fuel, but at the formal hearing Handy testified that it was not intended to represent the "best controlled similar source". 5-3-04 TE at 245-47; Jt. #54 at Red 104. In Jt. #44, TGC's case-by-case MACT determination dated December 12, 2001, at Red 41, TGC states that it "looked at the best performing sources burning bituminous coal from Western Kentucky #9 Seam and proposes to use all of the same control technologies being used plus WESP." Handy admitted that KEC did not evaluate whether a different control technology train could provide better mercury removal. 5-10-04 TE at 91:4-16 (Handy).

665. Referring to whether a similar source could be defined as a source burning bituminous coal from Western Kentucky No. 9 Seam, Dr. Fox said she had never seen similar source so narrowly defined in terms of fuel. 11-14-04 at 93. TGC states that the combination of control devices it proposes (low NO_x burners, SCR, particulate control, wet FGD and WESP) would equal or exceed control devices used to control mercury emissions on the best 2% of any currently operating similar coal-fired utility sources. Jt. #54 at Red 10. Dr. Fox states that 2% is not consistent with the definition of MACT. MACT is the best-controlled similar source, not the best controlled of 2% of any of the currently operating similar sources. Attachment 5 to Jt. #54, at Red 104, is labeled D.B. Wilson Electric Utility Mercury Emissions from EPA Software. As stated, TGC used EPA computer model based on the ICR database which allows it to put in

pollution control train equipment and mercury content, which would give it the percent of mercury reduction. TGC used that software and ran it for the configuration at the D.B. Wilson Generating Station to confirm that its pollution control train would achieve mercury reductions equivalent to or better than the best-controlled 2% of the sources. Id. at Red 105, entitled An Evaluation of a Control Alternative for an Electric Utility Furnace. TGC assumed that it had bituminous coal with 0.0797 ppm of mercury, as shown for D.B. Wilson. The model indicated that particular pollution control train would achieve a 77.7% mercury reduction.

666. DAQ did not agree with the best controlled similar source which was selected by TGC and in fact did not find TGC's choice "defensible under the regulations". 4-14-04 TE at 67:17-69:16 (Adams).

> Q In your analysis, what did you view as the best-controlled similar source?
>
> A For the metallic HAPs, the source category was probably any coal-fired power plant. For the acid gases, it would have been the best-controlled eastern bituminous coal plant, and that's because they – different chlorine contents on that. For mercury, it still would have been the best-controlled eastern bituminous power plant, even though the coal that Thoroughbred's burning has really lower mercury than most eastern coals, maybe all of them. But most of them for sure.
>
> Q Your analysis of best-controlled similar source, was that the same as what Thoroughbred's view was of best-controlled similar source, to your knowledge?
>
> A It wasn't the same as what they put into documents, no.
>
> Q Why did you look at it differently?
>
> A What they were submitting to us, really, I didn't find was defensible under the regulations.

667. DAQ and TGC worked closely with EPA in the development of the MACT limits for TGS. 4-14-04 TE at 51, 56-58 (Adams); 5-3-04 TE at 238-39 (Handy). EPA provided a list of all items required by 40 CFR Section 64.43 to be included in the MACT analysis and identified each HAP that TGC should evaluate in its analysis. P23 at 2-4. Because EPA had decided that a MACT was necessary, but it had not promulgated a MACT, DAQ relied heavily on EPA in working on the case-by-case determination. DAQ conferred with both Region 4 EPA and the chair of the EPA MACT work group. 4-14-04 TE at 53-56 (Adams). In his research, Adams also "…called up half a dozen states and talked to various reviewers". Id. at 64:23-25.

668. The SOB, Jt. #7, at 11, Section C (MACT), states:

> The applicant has submitted to the Division a case-by-case MACT determination for possible HAPs. Additional information received indicates that the control technologies being proposed at the facility will be equal to or better than any similar source. KYDAQ concurs with the applicant's determination. Based on the control technologies being used at the facility and the data provided in the USEPA documents the proposed control technology and emission limits will meet the control levels at other sources. According to the application the overall mercury removal from the facility is estimated to be greater than 80 percent with possible removals in excess of 90 percent. Similarly, other HAP emissions from the facility will be controlled by the combination of dry ESP, wet FGD and WESP. Based on the proposed control technologies and the reductions expected, the facility should meet the requirements for the best-controlled similar sources and therefore complies with all applicable MACT requirements.

669. TGS must meet the more stringent of either its permit limit or EPA's final MACT rule limit. Id. at 70-71 (Adams); 2-19-04 TE at 156:4-14 (Andrews).

Expert Opinions on MACT*:*

Lillestolen

670. As of the date of permit issuance, Lillestolen says there were no commercially available control technologies for mercury. He emphasizes that as stated in the January, 2002, letter from ALSTOM, Jt. #44, at Red 99, based on the ICR data and ALSTOM findings,

ALSTOM was not willing to guarantee 80% for mercury. Instead, ALSTOM believed it was reasonable to *estimate* that the mercury removal in the configuration that it described would be in the range of 85%, but accounting for contingency allowance, it would be prudent to estimate a value of 80%.

671. As of the date of Lillestolen's testimony in March 2004, if ALSTOM were asked to provide a system that would achieve 90% reduction of mercury for TGC, it would give it consideration. 3-16-04 TE at 124. At that time (March 2004), ALSTOM was attempting to commercialize a technology that relies upon activated carbon and primarily in combination with a fabric filter to control mercury to specific performance levels. Id. at 124. However, ALSTOM was not in a position in October 2002 to support offering such a configuration and making guarantees. ALSTOM began offering the configuration with guarantees as of summer 2003. It did begin talking to customers in early December 2002 about this.

672. ALSTOM was generally aware, as of the beginning of October 2002, that activated carbon injection plus a baghouse added after reheat at the end of TGS's pollution control train would achieve greater mercury removal than the TGC control technology alone. Id. at 132. This answer is based on the ICR data attached to ALSTOM's letter, Jt. #44, and partly on the remainder of the data ALSTOM was developing for its predictor model, which is based on long-term testing for mercury in Europe. ALSTOM was hoping that technology might be transferable to pollution control technology for coal-fired boilers.

673. P71 is a document dated December 2, 2002, announcing that ALSTOM Environmental Control Systems and ADA Environmental Solutions (ADA-ES), LLC, have entered into a partnership focusing on providing the required equipment and modifications to achieve up to 90% removal of mercury meeting all applicable standards. It further states that

“(t)he partnership will combine ADA-ES’s leading technology position in PAC based mercury removal, acquired through years of development including Department of Energy sponsored projects, with ALSTOM’s technology in particulate collection (Electrostatic Precipitators and Fabric Filters) and ALSTOM’s experience in mercury removal in the waste to energy business.”

674. Lillestolen acknowledges that as of October 2002 ALSTOM had experience in mercury removal in the waste-to-energy business and had a mature technology in particulate collection. 3-16-04 TE at 154. P71 was offered as rebuttal to the fact that these technologies were infeasible prior to October 2002. ALSTOM was at the time of Lillestolen’s testimony, in March 2004, guaranteeing 90% mercury control on coal-fired boilers. However, he testified that TGC could not have bought a process for the control of mercury as of October 11, 2002, based on the process or the marketing described in P71.

Bryan Handy

675. The TGC permit was the first MACT analysis on which Handy had worked. He did not recall reviewing any MACT analyses while he worked at DAQ.

676. Because this permit was the first case-by-case MACT analysis for a coal fired power plant in Kentucky, KEC researched other MACT determinations and applications and consulted with EPA on the case-by-case MACT.

677. Although Handy attempted to argue in the formal hearing that there was no best-controlled similar source, when shown his deposition, he acknowledged KEC had used D.B. Wilson as the best-controlled similar source because it was in Kentucky and burned similar fuel. 5-5-04 TE at 82:11-89:9.

Dr. Fox

678. Dr. Fox has prepared some 30 to 40 MACT analyses. 12-1-03 TE at 136:5-9. However, she acknowledges that none were on coal-fired power plants and none were for utilities the size of TGS. Her experience relating to mercury emissions is as follows. While she was a principal investigator at Lawrence Berkeley Laboratory, she did extensive investigation into the partitioning of mercury during combustion of a wide range of fuel types, and among other things, she developed the first mercury CEM (continuous emission monitor). In addition, she has done many field investigations and studies of mercury distribution in the environment in South America, in conjunction with oil fields in the Amazon basin, particularly in Ecuador and Peru.

679. Dr. Fox relied on the ICR data in forming her opinions about mercury MACT in this case. She opined that the ICR database is one of the best and most comprehensive data sets that is available and many agencies have implemented mercury control rule-making based on that data set. She opined that TGC failed to appropriately establish the MACT floor. This opinion was also expressed by IDEM in stating that Peabody failed to explain why it chose control options with mercury control efficiencies lower than those achieved by other sources using fabric filters and FGD control. IDEM 5 to Sizemore depo., P159, pg. 1705.

680. There was never any formal MACT Tier 1 analysis to determine de novo what the TGS mercury emission limits should be to comply with MACT standards. 11-14-03 TE at 108 (Fox). Instead, TGC looked at the ICR database to see if there were any sources in that database that were burning Western Kentucky Seam 8 and 9 coal. There were not any, so TGC found a facility in that database that burned Seam 9 coal (D.B. Wilson) but which did not have the same pollution control train. It was only equipped with an ESP and an FGD. Since it was burning the same coal and had a less stringent pollution control train and TGC was burning a similar coal

with more units that would reform mercury, TGC claimed that the performance of that unit represented MACT for this plant without ever going through a formal Tier 1/Tier 3 MACT determination and identifying a similar source based on the universe of bituminous coal-fired boilers. TGC did not evaluate different control technology trains for the control of mercury, but instead picked the control technology train to address NPS concerns about visibility impacts on the Park and simply had ALSTOM evaluate what level of mercury control could be achieved by that train. ALSTOM estimated that the expected mercury removal efficiency would be 80%. Then the 80% number was used to estimate the mercury emission limit in the permit.

681. TGC concluded, since it had additional pollution control beyond what was at the D.B. Wilson facility, that its pollution control train was equivalent to the best-controlled 2% of the sources. Jt. #54 at Red 104. However, TGC assumed that its pollution control train would only achieve 80% control efficiency which is quite low because this particular analysis did not have an SCR system in it. The catalyst in an SCR system converts elemental mercury, which is hard to remove because it is insoluble, into oxidized mercury, which is easy to remove. This analysis did not include an SCR system, so it underestimated the mercury control relative to what would be expected at the TGC plant. This analysis also did not include the wet ESP, which would also remove some of the mercury. So even though this analysis shows a control efficiency close to the 80% that was assumed for the TGC facility, it is really irrelevant because it does not include two of the control systems that are present on the TGC pollution control train and which would allow higher mercury removal efficiencies, i.e., the SCR and the wet ESP. Another important difference between TGC and D.B. Wilson is the mercury content assumed in this analysis (0.797 ppm) is roughly half of the mercury content in TGC's coal (.15 ppm). Id. at Red 105.

682. Finally, Dr. Fox opines that this kind of an analysis does not constitute case-by-case MACT analysis. Running a computer model using a different pollution control train and a different coal type cannot be used to confirm TGC's selective MACT determination. Another problem is that D.B. Wilson burns more than coal. It burns coke and it burns coal from other seams. So even under TGC's narrow definition of what constitutes a similar source, D.B. Wilson does not qualify because it runs coke and coal from other seams. Finally, the ICR database itself does not include any actual mercury stack test data on D.B. Wilson. The only information in the ICR database on D.B. Wilson is coal quality data. EPA did not test it to confirm the mercury emissions, so the only support is the model using that pollution control train in a coal that is different from the source.

683. Dr. Fox was asked repeatedly on cross-examination whether she knows of any vendor in the world that was willing to guarantee 90% mercury removal prior to October 11, 2002. Although she did not do a study of that specific question, she points to Lillestolen's testimony which is that activated carbon injection was commercially available prior to October 12, 2002. She also mentions the long-term widespread use of activated carbon injection for incineration plants, both in the US and in Europe, which is referred to as technology transfer.

684. Dr. Fox opined that the MACT floor finding should have been the combination of spray dryer adsorber (SDA) and fabric filter, which was the best-controlled similar source.

685. P153-22, Candidate Hg MACT limits, is a bar chart, showing six bars, prepared by Dr. Fox showing the effect of mercury control efficiency on mercury emissions in pounds per year.[63]

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[63] On P153-22, the TGC permit limit corresponds to an 80% control efficiency and results in the emission of 420 pounds per year in mercury from the two boilers. If an 85% control efficiency had been used, the mercury

686. P153-23, entitled Candidate Mercury MACT (% Removal), is a listing prepared by Dr. Fox of facilities and information relating to mercury removal of 90% or better, which are candidate control levels which she opines should have been evaluated in a proper MACT analysis. 11-17-03 TE at 66:9.[64] The information included in P153-23 is the basis for the bar

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emissions would drop to about 300 pounds per year. If a 90% control efficiency had been used, the mercury emissions would drop to 200 pounds per year. With 95% control efficiency, the mercury emissions would drop to 100 pounds per year. With 96.5%, they would drop to about 60 pounds per year, and with 98% they would be roughly 30 pounds per year.

[64] Included in P153-23 are the following:

P121-69 is a technical paper written by authors from the US EPA, US DOE and EPRI, the utility industry's research organization. The report discusses a coal fired power plant labeled S2, which is a 1300 MW pulverized coal facility burning very high sulfur Ohio bituminous coal, and equipped with a SCR, ESP and Wet FGD like TGC, which achieved a 90% reduction in mercury emissions. Id. at 5,7. Although Dr. Fox acknowledged that there are uncertainties, she pointed out that there are many power plants in Germany that have been meeting 90% mercury control for a decade or more.

P25 is the Babcock and Wilcox report "How Low Can We Go?" which explains that a 90% removal can be achieved by B & W's process of adding low cost agents to a wet scrubber. Another technology also mentioned to achieve 90% mercury removal is fabric removal followed by advance adsorber involving additives. Dr. Fox opined that because TGC is using a wet scrubber, the process of additives could be used to achieve 90% mercury removal. (P25 was inadvertently listed as P120-7 on P153-23).

P120-56 is a Burns & McDonnell study showing that dry FGD systems on boilers firing bituminous coal will likely meet 90% mercury removal.

P123-152 and P120-56 relate to a consent decree with PSEG Power in Newark, NJ, where there was a $3 million program to install both dry FGD and SCR systems at the coal fired Hudson and Mercer Station. P123-152 is a trade publication called the McIlvaine utility fax alert dated January 21, 2002.

P137-106 is the PSD permit application for the Cash Creek facility in Louisville which is for a mine mouth PC boiler to burn western Kentucky coal. Burns and McDonnell is the engineering firm on both Cash Creek and TGC. The Cash Creek application, which is dated September 2001, proposed 90% mercury removal using an SCR filter. 11/17/03 TE at 30:18. Another company, WULFF, proposed a pollution control train to TGC that would achieve over 90% mercury removal. Id. at 48:24.

P137-142 is a technical paper dated October 2001 stating that cost estimates were developed using powdered activated carbons to achieve a minimum of 80% mercury removal at plants using electrostatic precipitators and a minimum of 90% removal at plants using fabric filters. This exhibit was in TGC's files.

P137-229 is a PSD permit application for the Santee Cooper facility in SC dated March 2002. It shows 90% mercury removal with low NOx burners, SCT, ESP, and FGD.

P120-60 is an EPA report dated September 2000 on the performance and cost of mercury emission control technology applications on electric utility boilers. Two options for removal efficiencies and cost for high sulfur bituminous coal boilers are evaluated: PAC injections with a spray dryer ESP and secondly, PAC injection plus fabric filter, both of which show a 90% control efficiency as feasible and cost effective. On page 14, a table shows that based on the ICR data that an ESP plus a wet FGD and a plant firing high sulfur bituminous coals and without the need for any additional add-on mercury that 97% removal can be achieved in one case and 94.5% in another case. On page 10, 95% is calculated from information in various other pages in this report where it reports that 70% oxidized mercury with the SCR converting 55% and 100% FGD.

P123-144 is a McIlvaine utility fax alert dated March 1999 referring to McDermott stating that relatively low cost additives and process changes can provide 50% mercury removal in the precipitator and 90% mercury removal in a system with coal cleaning and scrubbers.

P137-53, TGS's Ultra Low Emission Project, is a proposal to DOE to install a certain sequence of pollution control systems on one of the two 750 MW boilers at the TGC project. On page 6, it states that at least 90% mercury removal will be achieved through the combined contributions of particulate removal in the fabric filter and oxidation of mercury in the ASCR (Advanced Selective Catalytic Reduction) for subsequent capture in the IAT (Integrated Advanced Tower) wet scrubber with additives. It further states that the technology is inexpensive because the additives are inexpensive and are used in very small quantities.

P120-58 is a paper by Burns and McDonnell, Peabody's engineer, entitled Can Existing Air Pollution Control Tech Equipment Meet Future State and Federal Requirements for Control. The paper states that all dry FGD systems on boilers firing bituminous coal show attainment of 90% mercury control benchmark. Also, on page 12, it is stated that by comparison to figure two, it can be surmised that the baghouse wet FGD combination on a bituminous coal fired boiler although not directly tested in the ICR program would certainly be at or above 90%.

PAR123-131 is a paper by ALSTOM Power, which is providing the air pollution control train for TGC. The paper is entitled Operating Experiences of Mercury Collection by PAC Injection in Bag Filters. This exhibit states that injection of PAC into a fabric filter with a very low ash influx at the Gaston Station, the fabric filter being located downstream of an ESP having 97 to 99% fly-ash collection efficiency, gave 90% mercury collection efficiency.

P137-137 is a letter written by WULFF**,** one of the vendors who responded to the Black & Veatch bid package for the TGC project. WULFF proposed two different pollution control trains, neither of which is the ALSTOM train., and for both technical proposals, an extreme high **SO3** removal rate of 99% was shown and the mercury removal was measured in the range between 40-80% depending on the composition fly ash and reaction conditions. A higher rate of mercury removal of more than 90% can be reached by adding a small quantity of lignite coke. Thus, Dr. Fox pointed out that TGC had before it a proposal that was able to meet all of the permit limits proposed for the project and which was also capable of achieving greater than 90% mercury removal for this particular project.

P121-64A is a journal called Fuel Processing Technology. The article is entitled Activated Carbon Injection in Spray Dryer/ESP/FF for Mercury and Toxics Control and is dated 1994 . The article summarizes experience with mercury reduction on existing coal fired power plants. Plant D, an eastern US coal with baghouse, achieved 96.5% mercury removal without carbon injection and greater than 99% mercury removal with carbon injection.

P137-118 came from KEC files and is a run made using the EPA model in which it evaluated a pollution control train being considered which was capable of achieving greater than the 80% control which ended up as the basis of the mercury limits in the permit. This was not submitted in the MACT analysis submitted to the Cabinet.

P120-57 is an ALSTOM analysis (included in Jt. #44) dated January 2, 2002. On page 3 of 4, entitled Technology Combinations for Bituminous Coals, 98% removal is shown using a spray dryer adsorber and fabric filter.

P121-65A is an EPA report entitled Control of Mercury Emissions from Coal-Fired Electric Utility Boilers: Interim Report Including Errata Dated 3-21-02. It was adduced by Petitioners in support of their allegation that 98% removal efficiency for mercury is achievable at coal fired power plants. On page ES-10, three bituminous coal-fired boilers are shown achieving 98% removal efficiency – one using a spray dryer adsorber and fabric filter, a second using a spray dryer adsorber and fabric filter and SCR, and the third using a fabric filter and FGD. All have a fabric filter in common, which TGC said was infeasible for its facility. Dr. Fox stated that two vendors responded to TGC with fabric filter proposals – one was Black & Veatch which specifically indicated to Dr. Fox that the vendors believe it is feasible. Dr. Fox's opinion is that it is feasible; it is simply a matter of cost. TGC did not submit a cost analysis of doing a fabric filter with respect to its MACT analysis.

P137-34 is an EPA memorandum on the control of mercury emissions from coal fired utility boilers dated October 25, 2000, which came from KEC files and was received by DAQ on January 30, 2002. On page 7, table 2, there are two entries showing 98% Mean Mercury Emission Reductions for PC Fired Boilers, one is achieved with a spray dry adsorber and another is achieved with an SCR adsorber plus a fabric filter, both burning bituminous coal, as TGC uses.

P137-278 is a PSD permit for the Franklin Energy Coal Project (in Illinois) dated June 6, 2002. On page 36, under PC Boiler – Mercury Anticipated MACT, it is stated "(t)o maximize the reduction of this output, data show a total mercury capture of 97.6% is possible with the controls this BACT recommends for other criteria graph labeled P153-22. Dr. Fox stated that if one of the mercury MACT limits on P153-23 were chosen by TGC, the emissions from TGC would be cut by as much as half. The items listed in P153-23, coupled with research done on mercury, including the ICR data, supports Dr. Fox's opinion that the best controlled similar source would have spray dryer adsorbers and fabric filters or fabric filters and a flue gas desulfurization system.

687. PD153-24 is a demonstrative exhibit prepared by Dr. Fox entitled Hg Removal Technologies Not Considered. The listing of the technologies not considered include:

* Coal washing, (P137-44);
* Carbon filter installed in the duct work to absorb the mercury (used in Japan and Germany), Utility Fax Alert 641;
* Non-carbon absorbents injected into the flue gas stream (carbon and lime; and oxidized lime); and
* Baghouse plus reheat downstream of the WESP.

Tom Adams

688. Adams said there is very little robust data on the question of mercury removal. 4-16-04 TE at 165 (Adams). He said that DAQ considered eastern bituminous power plants for the best controlled similar source for mercury. DAQ's analysis of best-controlled similar source was not the same as TGC put in documents. "What they were submitting to us, really, I didn't find was defensible under the regulations." 4-14-04 TE at 68.

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pollutants for the Franklin County facility: Electrostatic Precipitation and wet FGD. A minimum of 90% control of mercury emissions will be achieved."

In a bullet without an exhibit no. but labeled "Pet. 8/15/03 production", Petitioners refer to a letter that the Institute of Clean Air Companies (ICAC), an organization that represents vendors of pollution control equipment, wrote in the MACT deliberations on mercury stating that ICAC believed 90% mercury removal was feasible at that point in time for bituminous coals.

P137-127 is the LURGI technical proposal, dated September 21, 2001, for an air quality control system in response to Black & Veatch's bid package. The LURGI bid is for a circulating dry scrubber and fabric filter. P137-153 is a letter from LURGI to Mirant, who at the time was a partner in the TGC project. Mercury is present in two forms, in the oxidized form and the elemental form. This letter indicates that the CFB scrubber proposed for SO_2 control by LURGI would be capable of removing 95% of the oxidized form and 80% of the elemental form with the addition of activated carbon which would result in an overall removal rate of 95% MACT. Dr. Fox recalled that WULFF was another vendor that bid on an air pollution control train that could achieve 98% removal.

689. Adams opined that at the time the permit was issued, the emission limit in the permit was the appropriate MACT. 4-16-04 TE at 156. He believed that 80% mercury removal was the maximum achievable degree of emission reduction for mercury for a pulverized coal boiler burning eastern bituminous coal based on the materials TGC submitted and a review of available data, mainly from the ICR database. Id. at 158-59. In addition, he believes that the procedures followed were adequate. 4-14-04 TE at 70.

690. With regard to the high removal numbers attributed to the ICR database, Adams testified that "(s)ince no one seemed to be able to duplicate those numbers, they weren't used." 4-16-04 TE at 162-63. When questioned about P153-23, Dr. Fox's demonstrative exhibit entitled Candidate Mercury MACT (% Removal), he said that while the exhibit contains good information, it does not reflect an existing source, which is the regulatory definition. He said that if DAQ erred by not including some of the phenomenally high mercury removals suggested in the ICR database, then EPA has also erred by not incorporating them in its proposed MACT rule. He said the ICR database numbers could not be duplicated based on the information DAQ had or that could be obtained for DAQ. 4-16-04 TE at 162-63.

Parties' Arguments on MACT

Petitioners

691. Petitioners contend that the mercury MACT limit is arbitrary because TGC failed to adequately analyze the emission limitation achieved in practice for the "best controlled similar source" as required by the definition of MACT. Petitioners maintain that TGC defined "similar source" too narrowly by defining it as only sources burning West Kentucky Seam No. 9 coal, and further, narrowing it to the D.B. Wilson plant. Petitioners point out that to determine if a source is similar, only two questions must be answered in the affirmative: 1) does the source

have comparable emissions; and 2) could the same types of emission control technologies be applied to both sources. TGC's narrow definition resulted in its failure to examine emissions from similar sources using different pollution technologies.

692. In addition, Petitioners urge that TGC's mercury limit does not provide the maximum degree of reduction, which they contend would be 90% or greater with a baghouse.

693. Moreover, Petitioners contend that the case-by-case MACT for pollutants other than mercury was also inadequate.

Cabinet

694. The Cabinet maintains that Petitioners incorrectly focus on the inadequacies of TGC's application rather than DAQ's MACT determination. The Cabinet points out that Adams did not limit his case-by-case MACT analysis to the best controlled similar source information that TGC provided, as indicated by the following testimony:

> Q. In your analysis, what did you view as the best-controlled similar source?
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> A. For the metallic HAPs, the source category was probably any coal-fired power plant. For the acid gases, it would have been the best-controlled eastern bituminous coal plant, and that's because they – different chlorine contents on that. For mercury, it still would have been the best-controlled eastern bituminous power plant, even though the coal that Thoroughbred's burning has really lower mercury than most eastern coals, maybe all of them. But most of them for sure.
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> Q. Your analysis of best-controlled similar source, was that the same as what Thoroughbred's view was of best-controlled similar source, to your knowledge?
>
> A. It wasn't the same as what they put into documents, no.
>
> Q. Why did you look at it differently?

> A. What they were submitting to us, really, I didn't find was defensible under the regulations. 4-14-04 TE at 67:17-68:14.

The Cabinet maintains that Adams explained why he did not include western coal in his analysis and states that he based his decision on information he received from EPA, Id. 68:15-69:16, and reviewed EPA's ICR data. 2-9-04 TE at 89:23-91:6. The Cabinet emphasizes that DAQ worked very closely with EPA on the MACT determinations because it was well aware that EPA was in the process of preparing a proposed MACT for electric generating units and was fairly well along on its work. 4-14-04 TE at 52 (Adams). Adams also contacted other states with regard to the meaning of the MACT regulation and how to implement it. Id. at 64-66.

TGC

695. TGC points out that Petitioners fail to identify a "best controlled similar source" to determine an applicable MACT floor lower than DAQ's determination for TGS. They fail to provide evidence of any similar source achieving in practice a greater removal rate than TGS. TGC emphasizes that EPA recently concurred in the preamble to its proposed MACT rule that 90% mercury removal is not currently achievable and may not be until 2018 or possibly later. CabR 24 at 12403. The parties agree that the MACT limit must be "achievable", which means it must be set at levels the source can achieve under all reasonably foreseeable worst-case conditions over the life of the plant. 12-1-03 TE 141 (Fox).

696. TGC urges that it is insufficient for Petitioners to speculate about or merely raise questions regarding a hypothetical best controlled similar source or to allege that DAQ might have reached a different conclusion. Compounding the lack of specifically designed mercury controls is the paucity of accurate and reliable empirical data to determine what is "achieved in practice". TGC defines best controlled similar source achieving in practice as achieving under

reasonably foreseeable worst-case conditions on a long-term basis. "Petitioners must prove by a preponderance of the evidence that, at the time the permit was issued, a best controlled similar source was achieving in practice (i.e. under reasonably foreseeable worst-case conditions on a long-term basis) greater emissions reductions for HAPs than those required for TGS".

697. TGC acknowledges that the ICR database, containing most of the data points available at the time TGS was permitted, TGC123-170 at 43, was then and still is the best information available. However, DAQ reasonably concluded that the data alone did not conclusively establish the level of mercury control achievable in practice under worst-case foreseeable conditions. 4-14-04 TE at 72-73 (Adams); 12-2-03 TE at 167 (Fox). DAQ requested TGC to compare the proposed control efficiency for mercury to a similar existing source. However, because it could find no plants with data on HAP emissions from the same general coal characteristics and the same proposed technology, Jt. #54 at Red 104, TGC predicted a theoretical mercury removal percentage for the D.B. Wilson facility because it burned a similar high-sulfur fuel and compared it to the proposed removal for TGS. TGC urges that no one other than Petitioners has suggested that DAQ considered D.B. Wilson a "best controlled similar source."

698. TGC states that it discovered no commercially available control technology to remove mercury from power plant emissions. 3-16-04 TE at 73-74 (Lillestolen). Therefore, it considered the best mercury emissions reductions from commercially available technologies designed specifically to control other pollutants. TGC argues that Petitioners presented no evidence to refute that the combination of technologies being used represents the best air quality control technology available for TGS. Instead, TGC states that Petitioners persist in claiming that fabric filter technology, coal washing and spray dry adsorber technology should have been

considered and selected. These technologies were rejected in the BACT analysis, and TGC points out that the MACT analysis is no different in the absence of a MACT floor.

699. While MACT does require consideration of the best controlled similar source, MACT also contemplates situations where best controlled similar source cannot be identified. TGC urges that neither DAQ not TGC could identify a best controlled similar source, because reliable data was lacking. The sources identified by Petitioners in the ICR database as having greater than 80% removal are not similar to TGS because they all use fabric filters, which TGS contends it cannot use. Because a specific best controlled similar source could not be identified, the MACT analysis essentially became the same as the BACT analysis described in Count 9. TGC contends that TGS will have controls that are as good or better than any source burning eastern coal; therefore, it will achieve emissions at least as good as the best controlled similar source. Petitioners admit that no permits were issued before TGS's with a mercury limit based on 90% reduction. 11-19-03 TE at 34 (Fox).

700. The high removal numbers attributed to the ICR database could not be duplicated. TGC distinguishes the following examples cited by Petitioners of TGS's ability to achieve 90% removal. TGC points out that WULFF's technical proposal to TGC was incomplete because it never followed up with any pricing and commercial terms. 12-11-03 TE at 138 (Tickner). Also, the Cash Creek application was never deemed complete by DAQ. 4-13-04 TE at 71-72 (Adams). Babcock & Wilcox's confidence concerning mercury removal changed when the context moved from promotional to a real project. TGC109 is a letter from Babcock & Wilcox regarding the Elm Road Project, stating that B&W's goal was to develop a system to reduce mercury emissions by 90%. "However, B&W does not consider the current developmental status of

mercury removal technologies to be mature enough to commit to a meaningful guarantee for mercury emissions at the present time and can only offer targeted mercury emissions values."

701. Adams contacted EPA Region 4 and the EPA MACT development work group. DAQ had a reasoned basis to reject the 97% or 98% removal efficiency as a long-term achievable limit for TGS. Further, TGC urges that absent proof that 90% mercury removal has been achieved in practice, Petitioners' position on MACT is unsupported and untenable.

702. With regard to non-mercury HAPs, TGC states that a MACT floor was not identifiable and the case-by-case MACT analysis was built on the BACT analysis. While other control technologies were considered, TGC urges that Petitioners have not identified an existing similar source continuously achieving a higher level of reduction than the reduction required of TGS for non-mercury HAPs.

Petitioners' Reply

703. In summary, Petitioners maintain that the preponderance of the evidence in the record demonstrates that MACT is a much lower emission limit than proposed in the permit. TGC neglected to submit this evidence to the Cabinet, and the Cabinet failed to discover it on its own. Thus, Petitioners urge that DAQ's MACT decision is arbitrary and capricious.

704. Petitioners maintain that DAQ never made a proper MACT floor finding. While DAQ determined that eastern bituminous pulverized coal boilers are similar sources for purposes of MACT, DAQ never made a proper MACT floor finding based on these similar sources. Petitioners urge that evidence they adduced shows that eastern bituminous boilers could achieve greater than 90% mercury removal, even 98% removal. The ICR database demonstrated that eastern bituminous coal fired boilers were achieving 98%.

705. The parties disagree on whether the ICR data provides a sufficient basis for a MACT floor finding, whether coal quality is a consideration, and whether a similar source is limited to pulverized coal plants that actually are controlled by the same pollution control train as TGS's. The courts have consistently concluded in challenges to rulemakings establishing emission standards for HAPs in various other industries under the 1990 revisions to the CAA that other approaches, besides measured long-term emission data, can be used to establish the best controlled similar source, so long as they are "reasonable". [65]

706. Next, the definition of "similar source" does not include any reference to coal quality. Despite TGC's claim that its coal is unique, Petitioners urge that it is a typical bituminous coal which could be controlled by the same types of pollution control systems that are currently widely used at bituminous coal-fired power plants. Also, the definition of similar source does not require control by the same methods, only the potential for control by similar methods. The technologies used on the existing fleet of power plants are used by TGC. However, other types of particulate control devices and SO_2 scrubbers achieve higher mercury removal. The type of coal that is burned does not restrict the use of these technologies; it only affects the design and cost of these technologies. Costs cannot be considered in determining the MACT floor.

707. Although TGC now maintains that there is no similar source, in its MACT analyses it assumes that a best-controlled similar source exists. For example, in Jt. #44 at Red

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[65] Cement Kiln Recycling Coalition v. EPA, 347 U.S. App. D.C. 127; 255 F.3d 855, 859, 862, 865; (D.C. Circuit 2001) (challenge of emission standards for hazardous waste combustors); Mossville Envtl. Action Now v. EPA, 361 U.S. App. D.C. 508; 370 F.3d 1232, 1241 (D.C. Circuit 2004) (challenge of emission standards for polyvinyl chloride and copolymer production facilities); Sierra Club v. EPA, 359 U.S. App. D.C. 251; 353 F.3d 976, 982-983 (D.C. Circuit 2004) (challenge of emission standards for primary copper smelters); National Lime Association v. EPA, 344 U.S. App. D. C. 97: 233 F. 3d 625, 630-633, 637-640 (D. C. Circuit 2000) (challenge of emission standards for Portland cement manufacturing facilities).

11, TGC states "(b)ecause the proposed controls meet and exceed the best similar source, alternative control technologies were not considered." See also Jt. #44 at Red 10 and 11; Jt. #33 at Red 84; and in testimony at 11-17-03 TE at 68:3-69:12 (Fox). Although Adams testified that the best-controlled similar source for metallic HAPs and mercury was the best-controlled eastern bituminous coal plant (DAQ did not limit its review to a source burning Western Kentucky Seam 9), he did not identify a specific best-controlled similar source, but said that "it was just research on all plants". 2-9-04 TE at 88:15-89:5; 4-14-04 TE at 67:17-68:4 and 4-16-04 TE at 153:22-155:15. Petitioners urge, however, that the best-controlled similar source is a single facility that "leads the pack, not a generic collection of unidentified plants."

708. Next, Petitioners explain that MACT and BACT analyses are distinguishable in several respects. The MACT analysis:

1) establishes a floor that must be met, regardless of cost, energy, or environmental impact;
2) is based on the best-controlled similar source while BACT is based on the lowest emission limit, the former encompassing a large population of sources;

3) can only consider non-air quality environmental impacts, while BACT considers all environmental impacts; and

4) is based on “similar sources,” where similar has been defined much more broadly than under BACT, bringing in a much larger universe of sources, including “transfer” technologies.

709. Petitioners point out that TGC argues that the BACT analysis for mercury satisfies a case-by-case MACT analysis for mercury; the BACT analysis for VOC satisfies a case-by-case for VOC (HAPs); the BACT analysis for sulfuric acid mist satisfies a case-by-case MACT analysis for the other acid gases, HF and HCI (hydrogen chloride); and the BACT analysis for PM satisfies a case-by-case MACT analysis for HAPs. However, Petitioners urge that these BACT analyses eliminated a number of widely used technologies which should have been considered in establishing the MACT floor.

710. In addition, although TGC asserts that technologies to control mercury must be “commercially available” and TGC uses this criterion to justify eliminating technologies, it points to no statutory or regulatory requirement that emission controls be “commercially available”.

711. Petitioners point out that even though Adams testified that the Cabinet did independent investigations and reviewed additional information in its MACT deliberations, 2-9-04 TE at 89:13-92:22 and 4-22-04 TE at 83:24-84:19, there is no documentation in the record. Indeed, the MACT analysis in the permit and TGC’s application are identical.

712. Next, Petitioners discuss the factors relevant to a MACT analysis. While TGC argues for the first time in its brief that the uniqueness of its coal is support for its MACT limits, the evidence does not show that its coal is unique, and there is no evidence in the record that sulfur content has any effect on mercury removal other than a positive effect. Mercury is

removed by the wet FGD and the wet ESP, which are designed to control the high sulfur content. Moreover, as stated before in this Report, the design basis sulfur of TGC's coal (in CBI - Confidential Business Information) is not unique compared to bituminous coals burned by the existing power plant fleet. Jt. #12, v. 1, April 2002 EPA Report, p A-8, Table A-12. Ash is beneficial for mercury; the more ash, the higher the mercury removal. Jt. #55, p 5 of 5. Although ash is a design parameter for SCR because it can erode an SCR catalyst, TGC did not explain why ash is relevant for HAPs. While the design basis ash content of TGC's coal is high (per CBI information), it is well within the existing fleet of power plants. Jt. #12, v 12, April 2002 EPA Report, p A-2, Table A-2. Although TGC argues that its coal has a low chlorine content compared to other bituminous coals, (400 ppm (0.04%) for TGS compared to 700 ppm (0.07%) for other bituminous coals), and because chlorine converts elemental mercury to more soluble oxidized forms, making them easier to remove in the wet FGD and wet ESP, the more chlorine the better. However, the chlorine content of TGS's coal is generally consistent with the ranges reported for other bituminous coals. The mercury content of TGC's coal, which averages about 0.15 ppm, is well within the range of bituminous coals used by the existing fleet of power plants. Jt. #12, v. 12, April 2002 EPA Report, p. A-8. The same types of pollution control technology can be used on virtually all coal-fired boilers, regardless of the type of coal that is burned. The type of coal only affects design parameters for the controls.

713. Petitioners maintain that the preponderance of the evidence indicates that the ICR data are reliable to establish mercury MACT for TGS and should have been used to identify the best-controlled similar source. The table attached to ALSTOM's January 2, 2002 letter, Jt. #54 at Red 14-15, is ALSTOM's summary of that data in which it categorizes the results of the tests according to coal type and pollution control train. ICR data has been widely relied on to

establish mercury control levels, including in the instant case, and Respondents do not explain why it could not have been relied on in conjunction with other data, or why statistical methods could not have been used to account for variability, as has been done in other rule makings. While there is a substantial variation from test to test and boiler to boiler for sub-bituminous coals, this is not necessarily so for bituminous coals. TGC does not distinguish between bituminous and sub-bituminous coals in its criticism of the ICR data.

714. Although the ICR data consists of three separate measurements of both the inlet and outlet to pollution control devices, coupled with simultaneous coal quality testing, less rigorous monitoring is required in the permit to determine compliance with the mercury MACT limit. 12-2-03 TE at 77:14-23 (Fox). The highest values in the ICR database, 97 to 98%, were replicated in nine separate tests on three separate boilers. Negative values (mercury concentrations at the stack that are higher than those at the boiler outlet, suggesting that mercury was being created) do not mean the ICR data are not reliable for the purposes advocated, namely to demonstrate that a higher mercury reduction has been achieved by the best-controlled similar source. The negative values are likely due to measurement error caused by inlets and outlets to pollution control devices that are about the same.

715. Petitioners point to several sets of short-term test data in the record – the ICR data, Massachusetts source tests collected as part of a rule making, and data published in an older scientific paper – and urge that these data validate each other and together confirm that the mercury MACT floor is greater than 90% mercury removal. This data set contains triplicate test data on 81 separate coal-fired power plants, selected to give the EPA 95% confidence that it had accurately sampled coal-fired boilers. Included in this data are seven existing boilers burning

bituminous coals that are achieving greater than 90% mercury control. PR295-1; 6-1-04 TE at 36:3-23 (Fox). These tests results are included in Jt. #12, PR291, PR 291-1, and PR292-2.

716. In an independent analysis of the ICR data, Burns & McDonnell, TGC's engineer, concluded that "it can be surmised that the combined mercury removal for a baghouse/wet FGD combination (originally proposed for TGC), although not directly tested in the ICR program, would certainly be at or above 90%. P120-58; 11-17-03 TE at 40:22-42:7 (Fox).

717. ALSTOM also independently analyzed the ICR data and reported an average of 98% mercury control for bituminous coal-fired boilers equipped with spray dryer adsorbers plus fabric filters and 97% control for those equipped with fabric filters plus FGD. Jt. #44 at Red 100. These high removal efficiencies for bituminous coal-fired boilers equipped with spray dryer adsorbers and fabric filters also have been reported by others based on non-ICR tests. P121-64A, p 419, Table 1, Plant D (96.5% to greater than 99% removal for a plant equipped with dry FGD and a baghouse). Petitioners note that ALSTOM does not criticize the ICR data, but rather relies on it to establish the mercury removal facility for TGS.

718. The highest removal efficiencies are consistently obtained for bituminous coal-fired units equipped with fabric filters plus a sulfur removal technology or with a spray dryer adsorber. P120-58, Figs 2, 3. Dr. Fox testified that this combination of technology is the best-controlled similar source for mercury for bituminous coal-fired boilers. 11-20-03 TE at 163:12-14; 12-2-03 TE at 130:7-9; 130:19-24; 132:1-17; 168:4-8 (Fox). The EPA concluded in January 2003 that "fabric filters are the most effective technology for controlling mercury emissions" from similar commercial, industrial, and institutional boilers. TGC121-070, p 1681.

Petitioners urge that others including TGC have relied on ICR data

719. While TGC points to a sister agency in Iowa in dismissing the ICR data as invalid for TGS, the subject facility, Council Bluffs, will burn a sub-bituminous coal, not a bituminous coal. TGC123-70, p 43 (Power River Basin or PRB coal). As stated, the ICR database is limited for sub-bituminous coals because the measurements were not reproducible due to poor removal efficiencies. Iowa ultimately set a mercury control efficiency of 83%, which is higher than the upper end of the mercury control range reported in the ICR database for sub-bituminous coals (73%).

720. Others relying on the ICR data to determine mercury control levels, include TGS's own engineers, as well as Massachusetts, Wisconsin and other states, and the EPA. 11-20-03 TE at 71:16-72:7; 6-1-04 TE at 47:23-48:10 (Fox). These agencies were not concerned with the so-called limitations that TGC urges. 12-2-03 TE at 86:13-20; 87:6-25 (Fox). TGC's own permitting contractor, KEC, also relied on the ICR database to support 80% mercury control for the pre-selected pollution control train. 12-3-03 TE at 114:10-115:9 (Fox); 5-4-04 TE at 8:4-12:6 (Handy); Jt. #54 at Red 104. Also, TGC's engineer, Burns & McDonnell, published a paper in September 2001 which analyzed the ICR data to determine the mercury control efficiencies that could be achieved by existing pollution control equipment on existing coal-fired units. P120-58. IDEM relied on the ICR data in concluding that the Cabinet had not properly determined MACT in this case. P159; IDEM 5, p 17: McCabe letter, p 3 of 7. The Massachusetts Bureau of Waste Prevention relied on the ICR data to support more stringent mercury emission standards for power plants than proposed for TGS. PR281, p 11-12.

Petitioners urge that the MACT floor for mercury is greater than 90% removal

Fabric filters –

721. The ICR data showed that the highest removal efficiencies are consistently obtained for bituminous coal-fired units equipped with fabric filters plus a sulfur removal technology or with a spray dryer adsorber. P120-58, Figs. 2,3. This is the combination Dr. Fox identified as the best-controlled similar source for mercury for bituminous coal-fired boilers. 11-20-03 TE at 163:12-14; 12-2-03 TE at 126:24-128:22, 130:19-24, 132:1-17, 168:4-8. Petitioners urge that TGC's submission on the infeasibility of baghouses was inadequate and did not consider an add-on baghouse with reheat, as mentioned by both Lillestolen and Shepherd. 6-1-04 TE at 231:10-25 (Fox).

722. The factors used to eliminate fabric filters in the BACT analysis cannot be considered in the MACT floor analysis. Moreover, the SOB does not contain any basis for eliminating them. 11-20-03 TE at 162:21-163:14 (Fox). Adams acknowledged that fabric filters were more effective at controlling mercury than EPSs, which were chosen by TGC in the BACT analysis. 2-9-04 TE at 121:25-122 (Adams). ALSTOM's summary of the ICR data also shows that fabric filters remove 89% of the mercury while ESPs remove 11% (hot-side ESPs) to 29% (cold-side ESPs).

723. In its March 2001, "Flue Gas Desulfurization Technical Analysis", Black & Veatch, TGC's engineers, included fabric filters as part of three SO_2 control options evaluated "due to their flexibility, especially if additives are required to be injected for removal of other future regulated pollutants such as mercury." P137-51, p 7-3. In other work, B&V analyzed six options to address NPS visibility concerns. All included fabric filters. P137-93. In its June 2001 report, "Emission Control Evaluation", B&V concluded that a fabric filter was feasible, but the inference is that cost was a factor in eliminating fabric filters. P137-61, p 14. Also see Jt. #17, at Red 144. As stated, costs cannot be considered in determining the MACT floor. In its "Air

Quality Control System Performance Matrix", P137-7, p TB1873, maintenance and bag replacement were discussed as issues to consider in reaching expected performance. Again, maintenance and bag replacement are cost items which cannot be considered in establishing the MACT floor. The matrix concluded that fabric filters plus other control equipment were expected to achieve up to 95% mercury control.

724. In response to the B&V bid package, three vendors – Babcock & Wilcox (P137-151, p TB5210), Lurgi (P137-127) and WULFF (P137-137) - provided bids based on using fabric filters and SDA technology (B&V bid wet FGD). Fabric filters are currently used or proposed for similar coals. Dr. Fox identified three facilities which are currently using fabric filters on similar high sulfur coals – Scrubgrass (PR280, p 3-2, Table 3.1), JEA Northside, and Sulcis. 12-3-03 TE at 60:14 to 61:3; 6-1-04 TE at 245-248 (Fox). B&V asked Lurgi whether corrosion, erosion, or solids buildup would occur with their proposed CDS-fabric filter train. Lurgi stated that the baghouse had been in service since early 1995 with no signs of corrosion or erosion. P180, pTB6995. Others using fabric filters on pulverized coal fired boilers, burning eastern bituminous coal are – Upshur Energy, P137-143, p 2-19; Cash Creek, P305, p 4-27, 5-32; Longview, PR235, p 3, condition 5.

725. Although TGC alleged technical constraints to the use of fabric filters in a document which was put into the record after the close of public comments, Jt. #17 at Red 147-48**,** it does not point to any correspondence from its engineers or vendors. It footnotes a conversation with Burns & McDonnell but not as to the ultimate conclusion and this was put into the permitting record after the ESP was chosen. The problems alleged in this document would occur only if the flue gas temperature drops below the acid dew point, resulting in condensation of acids, corrosion, and plugging of the bags. However, there was no engineering analysis

showing that the flue gas temperature would be less than the acid dew point. These issues are normally addressed during design and add to the cost of a fabric filter; they do not render the technology infeasible. Neither Lillestolen nor Dr. Fox agreed with most of these issues. 3-16-04 TE at 166:22-168; 6-1-04 TE at 231:19-25. Even assuming the problems occur, they could be addressed during design by using reheat or locating the fabric filters downstream of the wet FGD, after the sulfur had been removed. Shepherd testified that the "main limit on baghouse efficiency is how much you're willing to spend." P160, p 27:25. The issues raised by TGC are not problems if the baghouse is kept above the acid dew point using reheat. Id., p 113:15-23. Lillestolen and Dr. Fox testified similarly. Both fabric filters and reheat were technically feasible before the permit was issued. 3-16-04 TE 125:25-126:1-3(Lillestolen).

726. Carbon injection into the fabric filter for mercury control was feasible, but vendor guarantees were not available from ALSTOM in October 2002. Id. at 124:5-14. Lillestolen testified that if he had it to do over today, he would consider designing the TGS control system with a fabric filter plus reheat and carbon injection, downstream of the wet ESP. Id. at 121:21-122:3 (Lillestolen). Even though TGC provides no support for its contention that a permit limit is required to support a MACT floor finding, Petitioners point out that the original permit application for Peabody's nearly identical facility in Illinois, Prairie State, concluded that the mercury MACT floor was 95% mercury control. P211, p 3. This plant will burn higher sulfur, higher ash, generally worse quality coal than TGC. 5-4-04 TE at 213:2-9 (Handy); 12-5-03 TE at 5:24-6:8 (Tickner). The ICR database shows high mercury removals which were reported nearly a decade before TGC applied for its permit, on a full-scale, bituminous coal-fired boiler. P121-64A, p 419, Table 1, Plant D; 11-17-03 TE at 57:25-58:13 (Fox). The high removal efficiencies were demonstrated consistently in the ICR tests on multiple facilities, in fact, on every single

facility firing bituminous coal equipped with a spray dryer adsorber and fabric filter, or nine units. See Jt. #12, v 1, p 6-22, Table 6-7, Post-combustion control: Dry FGD Scrubbers (The range in mercury reduction efficiencies is 96.56% to 99.23%). The ICR database removals were also uniformly higher for units equipped only with fabric filters.

Carbon injection –

727. Petitioners adduced evidence to show that a full-scale carbon injection system on a bituminous coal-fired boiler achieved over 99% mercury control a decade ago. P121-64A, p 419, Table 1, Plant D; 12-2-03 TE at 109:13-113:6 (Fox). The EPA prepared detailed cost estimates for 90% mercury control more than two years before the TGC permit was issued. P120-60; 12-2-03 TE at 108:11-20 (Fox).

728. A German company, Donau Carbon, would guarantee about 90% mercury reduction for a coal similar to TGS's coal. PR290; 6-1-04 TE at 20:22-21:18 (Fox); PR322; 6-1-04 TE at 23:4 – 22 (Fox). This technology was commercially available at the time the TGC permit was issued. In fact TGC's engineer, Burns & McDonnell, evaluated the use of carbon injection for TGC. The report was not produced in discovery and was never submitted to the Cabinet. P103-31; 5-5-04 TE at 140:13-141:20 (Handy).

729. The TOXECON™ process, offered by a U.S. firm, injects activated carbon upstream of a COHPAC™ baghouse located downstream of an ESP. PR285. The use of this process has been in continuous operation since 2001 on a coal-fired power plant in Alabama. PR281, p 15-16; PR285.

Carbon filters -

730. Packed beds of sorbent material, typically carbon, have been used in Japan and Germany to remove mercury, dioxins, and other HAPs from a wide range of combustion sources,

including coal-fired power plants. 11-17-03 TE at 74:24-75:1 and 77:19-24; 6-1-04 TE at 65:9-73:18 (Fox). One example uses a packed bed of activated coke to simultaneously achieve 90% mercury removal, 80% NO_x removal, and 99% SO_2 and SO_3 removal. PR282, PR283, PR313.

Additives -

731. The additive, TMT (trimercapto-s-triazine, tri-sodium salt), is used on virtually all coal-fired power plants in Germany to control the mercury content of scrubber waters, and has the added benefit of achieving 90% control of mercury emissions from the stack. PR284; 6-1-04 TE at 24:15-27:1.

Coal washing -

732. Coal washing was not considered in the case-by-case MACT analysis. P137-44; 5-5-04 TE at 136:10-137:21 (Handy). Coal washing was eliminated in the BACT analysis due to cost, energy and environmental factors, factors which cannot be considered in establishing the MACT floor. Petitioners suggest that coal washing is widely used and likely is used by the best-controlled similar source.

733. Coal washing would reduce mercury by about one-third for Kentucky Seam 8 coal. For Kentucky Seams 9 and 14, data shows 24% mercury reduction, 46% arsenic reduction, and 51% ash reduction. PR232, p 34; 6-2-04 TE at 113:11-114:9 (Fox).

Vendor guarantees -

734. The only evidence cited by TGC that vendor data is not reliable is Tickner's testimony on a letter from Babcock & Wilcox submitted to Wisconsin in the Elm Road case, stating that they would not guarantee 90% mercury removal for that facility. However, Wisconsin rejected the claims in this letter and issued a permit based on 90% mercury control. 12-2-03 TE at 50:4-7 (Fox).

735. Petitioners point to a number of organizations which have determined that a higher mercury efficiency removal than required for TGS is achievable. They include the following: the Institute of Clean Air Companies, an organization that represents pollution control equipment vendors, recommended to the EPA Mercury MACT Work Group that "(t)he standard (MACT) for bituminous coal should be 90% removal or a comparable emission rate." P168, P2; 11-17-03 TE at 63:12-22 (Fox); NESCAUM, the Northeast States for Coordinated Air Use Management, is a non-profit association of air quality divisions of the state departments of environmental protection of Connecticut, Maine, Massachusetts, New Hampshire, New Jersey, Rhode Island, and Vermont. PR280, p ES-3; 6-1-04 TE at 39:6-40:12. (Fox); Massachusetts - the state of Massachusetts has promulgated regulations to control mercury emissions from coal-fired power plants. 310 CMR 7.29. Testing of mercury emissions was required by five large coal-fired power plants. Four of the five were achieving mercury removals of about 90% with existing controls. 6-1-04 TE at 38:11-39:1 (Fox).

736. In rebuttal, the Cabinet introduced a number of MACT analyses that had equivalent or higher (less stringent) mercury limits in an effort to justify its own mercury MACT determination. Petitioners urge that these permits, which postdate TGC's permit, are not relevant for two reasons. First, MACT is the "best-controlled similar source". Thus, facilities permitted with higher mercury limits do not assist in identifying the "best controlled similar source". 6-16-04 TE at 10:8-15 and 11:14-19 (Fox). Second, most of these facilities would fire sub-bituminous coals. "PRB coals represent a worst case for mercury control." Id. at 18:1-2 (Fox); CabR227-1 (PlumPoint); CabR26, 27 (MidAmerican) and CabR30 (Whelan).

737. Petitioners point to a number of permitting materials, indicating that the best-controlled similar source could meet a lower mercury MACT emission limit and/or higher mercury percent reduction than TGS.[66]

738. Based on the following, Petitioners urge that TGC was aware that the mercury MACT floor was lower than it proposed but never disclosed what it knew to the Cabinet. TGC did not submit the following evidence to the Cabinet:

* Two of the bidders on TGC's bid package for the boilers and air pollution control train, Lurgi and WULFF, indicated their proposed pollution control trains would meet greater than 90% mercury control. P137-153 (Lurgi); P137-137 (WULFF).

* Black & Veatch also prepared two other documents that indicate greater than 90% mercury control was achievable – an evaluation of emission control technologies in June 2001, P137-61, and the Air Quality Control System Performance Matrix, P137-7, evaluating technologies for mercury control.

* Black & Veatch also prepared the original permit application for Prairie State, Peabody's nearly identical facility in Illinois. This application, submitted on October 19, 2001, concluded that the mercury MACT floor was 95% mercury control, consistent with the matrix

[66]These permitting materials include:
MidAmerican – This permit includes a mercury limit that is nearly two times lower than TGC's, and also requires the use of carbon injection, which was found to be commercially available, represented "beyond-the-floor" MACT technology and could achieve at least 83% mercury on a sub-bituminous coal, which is high. 12-2-03 TE at 61:16-63:12 (Fox); TGC 123-170.
Roundup - While Adams initially claimed the Roundup mercury limit was about the same as TGC's, 6-14-04 TE at 31:5-9, when pressed, he admitted that the Roundup limit was 17% lower. Id. at 146:12-148:15.
Birchwood, VA - This facility, which was included in EPA's RACT/BACT/LAER Clearinghouse and was included in TGS's case-by-case MACT determination, was permitted with a much lower mercury emission rate than proposed as MACT for TGS. The TGS mercury MACT permit limit is 0.1047 tons per year per unit, Jt. #8, p 4, which is equivalent to 0.0239 pounds per hour or twice as much as Birchwood. P101-4, p 1, controlled emissions column.
Franklin Energy Project, IL – This PSD application has a proposed mercury limit nearly ten times lower than TGS's limit. P137-278, p 37, Table 16, with a minimum of 90% control of mercury emissions. Although this application was in KEC's files, it was not submitted to the Cabinet. P137-278, p 37; 11-17-03 TE at 61:18-62:20(Fox); 5-5-04 TE at 124:14-127:11 (Handy).
Cash Creek, KY –This PSD application concluded that greater than 90% mercury control could be achieved. It proposed a mercury limit of 1.995E-6 lb/MMbtu, compared to TGC's limit of 3.21E-6 lb/MMbtu. Jt. #33 at Red 21, Table 4.2-1, "Hg, 30-day" column.
Other permitting materials - Other facilities with more stringent mercury limits than proposed for TGS (not necessarily available before TGC's permit was issued), include: the Baldwin permit requiring 95% mercury control; the Elm Road, WI permit, with a 90% mercury control; and the Santee Cooper application, with 90% mercury control.

prepared for TGC. PAR211, p 3: 5-4-04 TE at 213: 2013 (Handy). This plant will burn worse quality coal than TGS.

* In July 2001, TGC proposed to demonstrate 90% mercury control on one of its two 750MW trains. P137-053, p 3.

* KEC modeled an alternate pollution control train that would achieve 97.4% mercury control (an alternate to the proposed pollution control system which would achieve 80% mercury reduction). P137-118; 11-17-04 TE at 47:20-49:13 (Fox); 5-10-04 TE at 88:13 – 90:1 (Handy). However, this second analysis was never submitted to the Cabinet. 11-17-03 TE at 51:18-53:11 (Fox); 5-10-04 TE at 93:18-94:24 (Handy).

739. KEC files also contained PSD applications prepared by TGC's engineer, Burns & McDonnell, indicating that other applicants believed 90% mercury control was feasible, including the September 2001 Cash Creek PSD application and the June 2002 PSD application for the Franklin Energy Coal project.

740. Finally, a draft of the ALSTOM January 2, 2002 letter, which TGC points to as justification for 80% control, concluded that 85% mercury control was feasible. P137-156.[67]

741. Petitioners point out that during the formal hearing, TGC argued that the proposed MACT standards were irrelevant. Now, however, TGC relies on the preambles to the January 30, 2004 (TGCR258) and March 16, 2004 (CabR24) proposed MACT standards for electric utility steam generating units to conclude that carbon injection was not commercially available as of January 2004 and to argue that "there is no basis for Petitioners to claim that in October 2002 the best controlled similar source was achieving in practice 90% reduction in mercury." Petitioners point out that the preambles are preliminary and do not reflect final agency conclusions or action. Adams acknowledged that the proposed MACT standards are "controversial". 6-14-04 TE at 132:4-133:16. They garnered 680,000 comments, more than any

[67] See footnote in Overview of Count 10 regarding EPA's finalization of Clean Air Mercury Rule (CAMR).

regulation ever published by EPA. While the draft standards assert that carbon injection was not commercially available as of January 2004, Lillestolen testified that ALSTOM has offered carbon injection technology for coal-fired power plants since December 2002. P71 and 3-16-04 TE. Petitioners argue that public comments filed by many regulatory agencies and vendors of pollution control equipment indicate EPA has erred with respect to the passages TGC relies on.

Petitioners urge that a non-mercury MACT analysis was not performed

742. Petitioners urge that the MACT analysis submitted by TGC and relied on by the Cabinet did not review the use of alternate control technologies and concluded that MACT for the non-mercury metallic HAPs: (VOC HAPs), hydrogen chloride, hydrogen fluoride, arsenic, beryllium, chromium, manganese, lead and chromium) is 98% control based on a pollution control train selected to address visibility issues. Petitioners urge that the control efficiencies used to calculate HAP emissions were not divulged and are not stringent enough, and do not demonstrate that the selected technologies meet the definition of MACT. 12-2-03 TE at 136:20-137:11 (Fox).

743. Petitioners again urge that a BACT analysis does not satisfy the obligation to make a case-by-case MACT determination. Thus, they urge that the PM BACT analysis does not satisfy the obligation to make a case-by-case MACT determination for these HAPs, as TGC contends. They also urge that the MACT analysis for organic hazardous air pollutants is inadequate because there is no support for the VOC (HAP) MACT limit and because the EPA methods used to demonstrate compliance measure only nonvolative organic compounds, whereas all organic HAPs must be regulated. 11-17-03 TE at 102:19-103:5 (Fox). Finally, Petitioners urge that the MACT analysis and resulting HAP permit limits exclude several HAPs that are present at high concentrations in TGC's coal. 11-17-03 TE at 98:19-99:20, 103:15-104:1, 108:25-109:17 (Fox).

Count 10 - Conclusions

744. Much of Petitioners' argument on this Count is a critique of the MACT analyses submitted by TGC. Indeed, DAQ is in agreement with Petitioners that TGC's analysis of best controlled similar source was not defensible under the regulations. For this reason, DAQ began

an independent analysis. The reason DAQ's analysis focused on permits and permits in process is because the focus of the regulatory definition is on emission limits which are actually achieved in practice. MACT is defined as "the emission limitation which is not less stringent than the emission limitation achieved in practice by the best controlled similar source, and which reflects the maximum degree of reduction in emissions…"

745. DAQ was not able to identify a best-controlled similar source, and indeed, Petitioners do not identify a single best-controlled similar source. Thus, DAQ moved to Tier 2, which is similar to the top-down BACT analysis.

746. At the time of the TGC permit, DAQ had performed only two or three independent analyses of case-by-case MACT. DAQ's independent analysis for TGS focused on other existing permits and permits in process for facilities which were burning eastern bituminous coal, which DAQ determined as a "similar source". Thus, DAQ's definition of similar sources is not in conflict with Dr. Fox's definition, which is that similar source would be all coal fired boilers firing coal or segregated by saying all coal fired boilers burning bituminous coal.

747. Adams correctly understood the regulatory definition of MACT to be an existing source which is in operation, i.e. a technology which is in use and functioning. The basic bar is a source that is in operation or that is permitted. 4-14-04 TE at 45-46. With regard to P153-23, Dr. Fox's demonstrative exhibit entitled Candidate Mercury MACT (% Removal), Adams found this was good information, but he opined that to the extent the information did not reflect an existing source, it was not encompassed in the regulatory definition.

748. The final version of the SOB, Jt. #7, at p. 11, states that DAQ considered "additional information" following TGC's submittal of its case-by-case MACT determination.

In retrospect, Adams said that some of the research DAQ did was not documented to the extent it will be on future permits. In other words, while Adams said he could have told anyone inquiring what sources he looked at (primarily the MACT promulgation Web page for mercury), he agreed that "additional information" does not advise the public what sources were investigated. 2-9-04 TE at 92.

749. Adams stated that DAQ's determination that 80% mercury removal was the maximum achievable degree of emission reduction for mercury for a pulverized coal boiler burning eastern bituminous coal was based on the materials submitted by TGC, and a review of available data, mainly from the ICR database. 4-16-04 TE at 158-59.

750. Thus, while DAQ considered the ICR database, it did not find that it conclusively established the level of mercury control achievable by TGC because the high removal numbers in the ICR database could not be duplicated.

> We did a review of the data on the best-controlled similar source, and I do not recall being able to duplicate these numbers based on the information we had or that could be obtained for us. We specifically asked for these numbers from both the MACT development group and EPA, because if 98 percent is being – if 98 percent is being achieved, that would be of prime importance for the MACT development. And since no one seemed to be able to duplicate those numbers, they weren't used….
>
> The MACT determination that we made achieved considerable notice from both Region 4 and the National EPA. And if this (the ICR database) was reproducible, quantifiable data, we could not have issued the permit, unless there's a large conspiracy out there. 4-16-04 TE at 162-164 (Adams).

In addition, with regard to the ICR database, Adams stated:

> There was a lot of discussion about the information in the ICR database, and the main thing I can say about that is if we erred on not including some of those phenomenally high mercury removals that have been suggested that have been in there, then also the USEPA has not erred but committed major

> fraud because they didn't incorporate those into their final MACT or proposed MACT, either, and they were certainly under an obligation to look at the information and use the best-controlled similar source.
> 4-14 -04 TE at 73.

751. As I stated in the introduction to this Report, there was considerable discussion regarding the admission of exhibits which postdated October 11, 2002, the date of issuance of the permit. Because DAQ would not have had access to exhibits which were available after October 11, 2002, in reaching its permit determinations, I disallowed such exhibits, and such exhibits were labeled "avowal" exhibits. However, when rebuttal began, exhibits which postdated October 11, 2002, were admissible if they tended to show that DAQ's permit decisions were either erroneous or arbitrary, or conversely, if they tended to show that DAQ's permit decisions were neither erroneous nor arbitrary. As stated in the overview to this count, EPA's "Proposed National Emission Standards for Hazardous Air Pollutants; and, in the Alternative, Proposed Standards of Performance for New and Existing Stationary Sources: Electric Utility Steam Generating Units" was issued in January 2004 and supplemented in March 2004, during the course of the formal hearing in this case. Evidence pertaining to these proposed standards was not allowed during the parties' cases in chief, but in rebuttal the federal regulations publishing the proposed standards and supplement were introduced. TGCR258 and CabR24.

752. The proposed standards, even though controversial, are evidence which tends to show that DAQ's mercury MACT determination was neither erroneous nor arbitrary.

753. Even if other agencies have found that the ICR data are reliable to establish the best controlled similar source, Petitioners offer no support for requiring that the ICR data conclusively establish the best controlled similar source. Petitioners cite several cases in which rulemakings were challenged which established emission standards for HAPs in other various

industries. Petitioners point out that the courts have consistently held that other approaches, besides measured long-term emission data, can be used to establish the best controlled similar source as long as they are reasonable. Again, this does not establish that DAQ erred by failing to base its case-by-case MACT determination solely on the ICR data. In its Proposed Standards, EPA notes, at TGCR at 4670, that the ICR test report data "shows a significant degree of variability even within a given subcategory. The EPA, therefore, decided it was necessary to develop a methodology to address the multiple sources of the observed variability in order to assure that an emission limitation value could be derived that was representative of what was actually being achieved by the best performing units under all conditions expected to be encountered by those units".

754. Indeed, Adams testified that DAQ reviewed the ICR database, consulted with other state agencies, and worked intensely with the EPA MACT development group in arriving at its mercury MACT determination. This is not contrary to what Petitioners are seeking, even though they argue that the final determination should be a significantly higher mercury removal.

755. I conclude that following DAQ's review of the ICR data, it was reasonable to consult with the MACT development group and Region 4 to see if these numbers could be duplicated before DAQ reached its mercury MACT determination. DAQ's analysis and determination were especially reasonable given the few MACT analyses which had been performed by DAQ and the advanced stage of the MACT development group. I conclude that Petitioners have failed to establish that DAQ's mercury MACT determination is erroneous or arbitrary.

756. I also conclude that Petitioners have failed to show that DAQ erred in determining the non-mercury MACT.

Count 11 - Single Source

Count 11 - Findings

Overview

757. This Count involves the issue of whether the power plant and nearby mine must be permitted as a single source for PSD purposes. The purpose of the "single source rule" is to ensure that facilities do not split certain related pollutant emitting activities (i.e. the mine and the power plant) into different entities for permitting, thus avoiding PSD requirements for some or all of their activities.

General Findings

758. The regulations which pertain to the single source rule are the following regulations which define stationary source, and in turn in defining building, structure or installation, set forth the three factors to be met for multiple sources to be considered a single source:

> 401 KAR 51:017 Section 1(38) **"Stationary source" means** a building, structure, facility, or installation which emits or may emit an air pollutant subject to regulation under the …(Clean Air Act). (emphasis added).
>
> 401 KAR 51:017 Section 1(9) "**Building, structure, or installation" means** all of the pollutant emitting activities which:
>
> 1) belong to the same industrial grouping,
>
> 2) are located on one (1) or more contiguous or adjacent properties, and
>
> 3) are under the control of the same person (or persons under common control) …
>
> In determining which building, structures or intallations belong to the same industrial grouping, Section 1(9) provides that "(p)ollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the

same major group (i.e., which have the same two (2) digit code) as described in the Standard Industrial Classification (SIC) Manual, 1987 …" (emphasis added)[68].

759. The parties agree that the second and third prongs of 401 KAR 51:017, Section 1(9) are met, i.e. 2) the power plant and the mine are on contiguous or adjacent properties and 3) the power plant and the mine are under the control of the same person (the proximity and common control prongs). It is the first prong, i.e. whether the power plant and the mine belong to the same industrial grouping, on which there is disagreement. It is not disputed that the power plant and the mine do not have the same SIC code - coal mining operations have an SIC code of 12; facilities which generate, transmit and/or distribute electric energy for sale

[68] TGC cites to Harsco Corp. v. Natural Res. And Envtl. Prot. Cabinet, Ky. App., 2003-CA-000025-MR, 2004 WL 1103594, 4, 10 n.9 (May 14, 2004) in its post hearing brief wherein the Court of Appeals, in an unpublished case, stated that all three factors of Section 1(9) must be met for multiple sources to be considered as a single source. In their reply brief, Petitioners point out that the Harsco case was inappropriately cited because it was an unpublished case. Petitioners also point out that two motions for discretionary review were filed with the Kentucky Supreme Court, by private parties and by the Cabinet. On January 17, 2005, TGC filed notice that the Supreme Court had denied the Cabinet's motion for discretionary review and had granted the private parties' motion to withdraw their motion for discretionary review.

have an SIC code of 49. However, Petitioners urge (and the Cabinet agrees) that the regulation simply requires that if pollutant-emitting activities have the same two digit SIC code, they must be considered a single source. However, they contend that this does not preclude a determination that pollutant emitting activities under different SIC codes are a single source.

760. In my Interim Report denying TGC's motion for directed recommendation on this Count, I point out that DAQ acknowledges that it did not make a formal determination as to whether the power plant and nearby mine are a single source. I then concluded that "Petitioners put on a prima facie case to show that DAQ was required to make a single source determination, and the determination would be that the mine and the power plant are a single source." Docket #273 at 24. This ruling was based on evidence adduced during the course of the formal hearing, up to the time of my ruling (on April 12, 2004), which showed that no formal determination had been made by DAQ because TGC agreed to make the emissions sources at the coal mine a part of its BACT determination and to examine those emissions units in the air dispersion modeling for the facility. Hence, the Cabinet urges that the PSD analysis overall would not be affected or change as a result of considering the mine and the power plant as a single source.

761. In Petitioners' case in chief, Don Newell, branch manager of DAQ's Permitting Branch at the time of the formal hearing, testified that DAQ never made a single source determination. 3-4-04 TE 60-61 (Newell). Subsequently, in the Cabinet's case in chief, however, the Cabinet adduced evidence that Edd Frazier had done research and made the determination for DAQ that the power plant and mine were separate sources. 4-14-04 TE at 93 (Adams). This contradiction in testimony was explained by the fact that Newell was not with the

Permitting Branch when the separate source determination was made, so he was not aware of it. Id. at 92-93.

762. DAQ's determination that the power plant and mine were separate sources is confirmed by Jt. #30 at 2 (letter from Tickner to Lyons); TGC218 at 3 (letter from EPA Region 4 to Lyons); and Jt. #63 at 9 (response to public comments).

763. As stated above, the primary SIC code for establishments engaged in the generation, transmission and/or distribution of electric energy for sale fall under Group 49, while the SIC code for the mine is Group 12. Jt. #35; TGC214 (relevant excerpts from SIC Manual).

764. TGC gave the following justification for treating the mine and power plant as separate sources: each facility has independent utility and could exist without the other; when the mine begins operations, all of its production will be sold to other facilities; and only after TGS is operational will the mine's output be directed to TGS. Jt. #35; 12-5-03 TE at 88 (Tickner)

765. However, in a letter dated July 18, 2002, from EPA Region 4's Chief of the Air Planning Branch, to the director of the Cabinet's Department for Environmental Protection, EPA commented that it understood that DAQ had determined that the power plant and mine are separate sources. EPA commented that "this determination and an explanation for this determination are not provided in the revised PD/SB". TGC218 at 3.

766. TGC agreed to include emissions modeling for both sources in the permit application for TGS and to apply BACT to both sources. Jt. #35 (letter from Handy to Markin). An agreement was reached between DAQ and representatives of TGC that the mine should be controlled to BACT levels. 4-14-04 TE (Adams) at 97.

767. The modeling for TGS included the relevant emissions points at the mine (those that are part of the mine to power plant system). 4-14-04 TE 95-99 (Adams). Jt. #57 at Red 68 (Table 6.3.1-2); Jt. #56 at Red 30.

Count 11 – Parties' Arguments

Petitioners

768. In their post hearing brief, Petitioners incorporate their earlier arguments on the single source issue, and urge that I have ruled in their favor on this Count. They note that even after the second draft permit came out, Jim Little of US EPA Region 4 believed that the permit was in error in not containing both the mine and power plant as a single source (citing to testimony by Sizemore (P159 at 103:11)).

TGC

769. TGC urges that DAQ presented a reasoned basis for its determination that TGS and the mine are separate sources. In a letter from Handy to Markin, Jt. #35, it is explained that while the mine will supply coal to the facility, the mine will have independent customers. Thus, the facility and the mine have independent utility. In addition, TGC states that the modeling for TGS included "all relevant emission points" at the mine (i.e. those that are part of the mine-to-power plant system), and TGC states it has agreed that the mine would be controlled to BACT standards. 4-14-04 TE 95-99 (Adams); Jt. #57 at Red 68 (Table 6.3.1-2); Jt. #56 at Red 30; Jt. #7 at 31-33; Jt. #35 at 4.

Cabinet

770. The Cabinet basically concurs with TGC's arguments and states that the single source issue was a comparatively minor issue in the permitting process. In light of TGC's desire that the mine be permitted separately from the power plant and TGC's decision that it would not object to DAQ considering all of the emissions, DAQ believes that environmental controls were not being neglected by a determination that the mine and power plant are separate sources.

Petitioners' Reply

771. In reply, Petitioners urge that even if a determination was made by the Cabinet, a preponderance of the evidence does not show that an analysis was conducted by the Cabinet on the single source issue.

Count 11 - Conclusions

772. I conclude that this issue is moot because of TGC's agreement that BACT will apply to both the emissions from the mine and the power plant. I will recommend that TGC's agreement be incorporated into the permit.

Count 14 - Enforceability

Count 14 - Findings

Overview

773. Counts 14 and 17 are interrelated in that they both address the enforceability of the permit. Count 14 involves permit conditions which Petitioners allege are not enforceable. Count 17 involves errors and omissions in the permit which Petitioners allege make the permit unenforceable. Count 2, the public participation count, is also related to these counts.

774. Permit limits are enforced through monitoring, recording and reporting. Monitoring can take many forms, depending on the nature of the underlying emission unit and applicable requirement. The permit includes several broad classes of monitoring: 1) continuous monitoring using a continuous emission monitoring system (CEMS), 2) periodic stack tests; 3) measuring the operational parameters of pollution control equipment; and 4) measuring a chemical that is related to the regulated pollutant (indicator or parametric monitoring). The only monitoring methods that measure actual emissions coming out of the stacks are stack tests and CEMS. The other methods rely on establishing a relationship between the regulated pollutant at the stack and an indicator of the regulated pollutant, e.g., opacity as an indicator for particulate matter.

775. On July 1, 2004, following the formal hearing, TGC submitted to DAQ a list of proposed administrative amendment/minor permit modifications to address some, but not all, of the items in Counts 14 and 17. Docket #299. TGC proposed that the Cabinet approve the amendment/minor permit modifications pursuant to Sections 13 (Administrative Permit Amendments) and 14 (Minor Permit Revisions) of 401 KAR 52:020, which provide that the source may implement such changes upon submittal of the request for the change.

776. On July 30, 2004, Petitioners sent a letter to DAQ in which they supported certain revisions proposed by TGC and opposed others. Docket #300. On August 12, 2004, DAQ received a letter from TGC replying to Petitioners' letter. Docket #308. The Cabinet stated in

its post hearing brief that the matter was under review by DAQ, but no determination had been made. However, on February 17, 2005, the Cabinet issued Revision #2 in response to TGC's proposed permit amendments. On March 21, 2005, Petitioners filed a petition to contest the permit modifications which they had objected to earlier. Docket #332. They urged that their petition be considered as part of this pending case without reopening the record or submission of additional arguments. By Agreed Order of the parties, filed on April 19, 2005, the claims raised by Petitioners shall be considered in this Report as part of File Nos. DAQ-26003-037 and DAQ-26048-037. Docket #339.

777. A review of the parties' arguments on Counts 14 and 17 is difficult because these arguments were filed prior to the issuance of Revision #2, but following TGC's proposal on July 1, 2004. Thus, each party commented on the proposed revisions in their post hearing briefs, and the Cabinet's brief set out what it believed to be DAQ's position on each proposed revision. Now that Revision #2 has been issued, I will set out in the Findings of Fact the items it includes, and I will attempt to state the parties' response to each item. Where all parties agree with an item in the revision, any issue dealing specifically with that item is now moot.

778. In Count 14, Petitioners enumerate six permit provisions which they urge are not "enforceable as a practical matter": 1) the HAPs limits are not enforceable; 2) numerous monitoring requirements are missing from the permit; 3) VOC limits are not enforceable; 4) the public does not have access to the operating procedures that are used to determine compliance; 5) the monitoring for PM is not enforceable as a practical matter; and 6) the permit lacks monitoring and reporting to make the emission limits for emission units 4-9 enforceable as a practical matter.

779. The Cabinet contends that the permit is enforceable as a practical matter as demonstrated through the testimony of DAQ permitting experts, Adams and Andrews, the extensive involvement and oversight of EPA, and the permit when read as a whole. The Cabinet cites to testimony by Adams regarding comments by Region 4 on the issue of enforceability. "I don't find her (Dr. Fox's) arguments have been any more strenuous than Region 4's, through Cesar Zapata, were. He was a stickler for enforceable and enforceable as a practical matter to the point of we – I couldn't begin to go through the iterations we had on this." 4-14-04 TE at 100-101. Adams also explained that the permit was subject to an extensive review by DAQ enforcement personnel. Id. at 114-15.

780. TGC urges that Petitioners fail to consider the following: 1) the permit contains multiple enforcement mechanisms that work together to ensure compliance with any one emission limit; 2) suggestions of additional methods of enforcement do not make the permit unenforceable; 3) certain information related to TGS's operation cannot be known until the facility is actually built; and 4) TGC has an affirmative obligation to demonstrate compliance to DAQ.

781. In reply, Petitioners address issues which can be found in both Counts 14 and 17. The reason for doing this, Petitioners state, is to reply to Respondents' defense that multiple enforcement mechanisms work together to ensure compliance with any one applicable requirement. Petitioners identify each of the multiple enforcement methods for each pollutant, emission unit, and activity and urge that each provision individually or in combination is not enforceable. Petitioners cite six reasons why they believe that multiple monitoring methods do not ensure compliance. First, the "secondary" methods do not measure emissions coming out of the stack, they monitor surrogates or indicators, and the permit contains no provisions that state

that a violation of the indicator is a violation of the underlying applicable requirement. Second, some of the indicators rely on infrequent stack tests[69] that are not representative of normal operation, e.g., PM_{10}, VOCs, HAPs. Thus, the indicators themselves must fail for their stated purpose. Third, each monitoring method in the proposed chain of methods would not itself yield "reliable data" or is not clear enough to be enforceable. Fourth, some of the conditions that Petitioners maintain are not enforceable are subject only to secondary monitoring that is not linked in any fashion to the emissions from the process (auxiliary boiler, cooling towers, material handling equipment and diesel engines). Fifth, some of the applicable requirements, due to the way they are stated, cannot be enforced, i.e., an inspector cannot determine if an annual emission cap is being met on HAPs limits expressed only in tons per year. Sixth, the permit relies on descriptive information.

782. Petitioners also urge that regulated pollutants monitored using initial only or annual stack tests are not enforceable, i.e. PM or PM_{10}, VOCs, HAPs and SAM (sulfuric acid mist) limits. Petitioners urge that stack tests should be conducted biannually to quarterly for the first one to two years of operation, with the option of reducing the frequency to annual if more frequent testing demonstrates compliance. This stack testing is supplemented by certain additional indicator parameters under the continuous assurance monitoring program (CAM) to provide a reasonable assurance of compliance with applicable requirements. The proposed indicator monitoring in the permit does not comply with the CAM regulations, and thus, Petitioners urge that the applicable requirements they seek to implement are unenforceable.

General Findings

[69] A stack test measures the emissions at the stack by inserting a probe into the stack to collect a sample. 4-16-04 TE at 49:19-50:8 (Adams). Stack tests are also called source tests, performance tests, and compliance tests.

783. The findings related to permit conditions are found in the permit itself, which is Appendix No. 4 to this Report. The relevant portions of the permit are cited in the Parties' Arguments and Conclusions.

784. 401 KAR 52:020, Section 10, provides that "(p)ermits shall contain terms and conditions as provided in Sections 1a to 1c of the 'Cabinet Provisions and Procedures for Issuing Title V Permits' (Title V Policy Manual), which is incorporated by reference in 401 KAR 52:020, Section 26(1).

785. A Title V permit shall contain a provision stating that all emission limits and standards shall be "enforceable as a practical matter". Title V Policy Manual, Section 1a, para. 15a.

786. "Enforceable as a practical matter" means that the emission or other standards include:

> (a) Technically accurate emission standards and the portions of the source that are subject to the standards;
>
> (b) A time period adequate to demonstrate compliance with the standards; and
>
> (c) The method the source will use to achieve and demonstrate compliance with the standards, including appropriate monitoring, recordkeeping, and reporting. 401 KAR 52:001 Section 1(31). See also 401 KAR 51:001, Section 1(46) for the same definition.

787. The following state and federal regulations pertain to the enforceability of TGC's permit: 401 KAR 50:045; 51:017, 52:001, 52:020, 52:060, 59:016, 60:005, and 63:010, as well as 40 CFR Parts 60, 64, and 75.

788. The EPA was very involved in enforceability issues in the permit. 2-5-04 TE at 155; 4-14-04 TE at 100-01 (Adams). The permit also included an extensive review by enforcement personnel within DAQ. 4-14-04 TE at 114-15; 105-106 (Adams).

789. Revision #2 contains the following twelve revisions. In my listing of each individual revision, first, the item is given a number corresponding to the number in TGC's proposal; next, the capital letter following the number relates to letters assigned by Cabinet counsel in its post hearing brief (See Count 17). The underlined portion states the subject matter of the item; the actual revision follows; and is followed by the parties' position.

(1)C – Conflicting coefficients between SOB and permit with regard to the 24-hour limit for SO_2

Revision #2: The equation in Section D.4 on p. 35 of the permit is revised to reflect the more stringent condition, by changing the coefficient from 135% to 110%.

All parties agree.

(2)D – Omission of exponent "2" from 24-hour SO_2 limit equation

Revision #2: Equation in Section D5 on p. 35 of 50 is revised by changing the "n" in the denominator in the prior version to "n^2" in the revised version.

The parties agree.

(3)H – Grab or composite samples

Revision #2: The permit is amended to clarify that quarterly composite samples for HAPs are required.

All parties agree.

(4)Aa – Error in regulatory reference

Revision #2: The reference in the permit to 401 KAR 50:055, Section 1(a) is corrected to read "Section 2(1)(a)".

All parties agree.

(5)E – Error in Cadmium limit

Revision #2: The permit is revised so that the table in Section B.2(m) on p. 4 of 50 states that the cadmium limit for each PC boiler is 0.0119 tons per year.

All parties agree.

(6)B – Non-mercury HAP permit limits

Revision #2: Table B7(e) on p.14 of 50 is revised to state that the control technology for the non-mercury metallic HAPs (arsenic, beryllium, cadmium, chromium, lead and manganese) is wet and dry electrostatic precipitators with an approximate control efficiency of 99.5% to 99.9% control efficiency for PM.

All parties agree.

(7)F,G – Filterable/condensable PM_{10}

Revision #2: The reference to PM/PM_{10} in Section D.1 on pg. 35 of 50 has been clarified to state that the regulated particulate matter pollutant is PM/PM10 (filterable and condensable).

All parties agree.

(8)J – Clarify frequency of stack testing

Revision #2: The permit, Section B.3(b) on p. 4 of 50 has been revised to require TGC to conduct a performance test for particulate emissions annually after demonstrating compliance with the allowable standard.

All parties agree.

(9)I –Clarify HAP compliance testing

Revision #2: The permit, Section B.3(g) is revised to state that the permittee shall take a representative sample of the fuel "as fired" and analyze it to determine the HAP content in the fuel. This information shall be used to establish a correlation between the sample's HAP content and HAP emissions for monitoring purposes, except for VOC (HAPs). The permittee shall demonstrate compliance with these emissions limits annually. This testing shall be used to validate the correlation between composite sample HAP content and HAP emissions, except for VOC (HAPs).

All parties agree.

(10)O – Fuel oil sulfur content

Revision #2: The following sections of the permit are revised to consistently reflect that all fuel oil will have a 0.05% sulfur limit – Section B Description, p. 2; Section B Description, pg. 15; Section C Description 1, p. 34; and Section C Description 6, p. 34.

All parties agree.

(11)W – Clarify compliance provision contained in SOB with permit

Revision #2: The permit, Section D.1 on p. 35 of 50, is revised to state that the listed pollutants (PM/PM10) (filterable and condensable), sulfur dioxide, carbon monoxide, nitrogen oxides, VOC and visible (opacity) shall be measured by applicable reference methods, or equivalent or alternative methods approved by the Cabinet (and USEPA, if required), and shall not exceed the respective limitations specified herein. (The prior version of the permit did not list VOCs).

All parties agree.

Revision #2: The monitoring provisions for the cooling towers in Section B.4 on p. 32 of 50 are revised to state that the permittee shall measure the total dissolved solids (TDS) content on at least a monthly basis. Measurement of TDS in the wastewater discharge permit associated the units as required by National Pollutant Discharge Elimination System (water) permit, may be used to satisfy this requirement if the effluent has not been diluted or otherwise treated in a manner that would significantly reduce the TDS content.

All parties agree, but Petitioners propose 0.0005% drift eliminators.

(12)M – Discrepancy between permit application and permit with respect to heat rate of boilers

Revision: The permit is revised so that Section B on p. 2 of 50 states that the nominal heat rate of the PC boilers is 7,443 MMbtu/hour.

All parties agree.

Count 14 – Parties' Arguments Followed by Conclusions[70]

Petitioners

[70] Since this Count has multiple subparts, my conclusions will follow the parties' arguments on each subpart.

790. Petitioners urge that the following six permit provisions (labeled A – F) are not enforceable as a practical matter:

A. HAPs limits are not enforceable, for three reasons

i. Test method not specified for coal.

791. Conditions B.3 (g), B.4 (j), and B.4 (m) indicate that the primary method of determining compliance with HAP limits is through quarterly coal sampling and annual stack tests, Jt. #8 at 5-10. However, Petitioners point out that the permit does not contain any sampling procedures for collecting the quarterly "grab" or "composite" coal sample or analytical methods for measuring their HAP content. Thus, they argue the HAP emission limits in Conditions B.2 (h), B.2 (k), B.2(1) and B.2 (m) are not enforceable as a practical matter.

ii. The sampling is not adequate to determine quarterly averages for beryllium, mercury, or lead.

792. Although conditions B.2(h), B.2(k), and B.2(1) for Emission Units 01 and 02 set emission limits on beryllium, mercury and lead, respectively, based on quarterly averages, Jt. #8 at p. 3, the testing required is only a single "grab" sample once per quarter. Id. at 7-10, Conditions B.4 (j) and B.4 (m). A single grab sample cannot be used to determine an average. Thus, the permit limits on beryllium, mercury and lead are not practically enforceable.

iii. Quarterly coal sampling is not adequate to assure compliance with HAP limits.

793. The permit requires only quarterly samples of fuel "as fired" for metallic HAPs. However, quarterly sampling is "not going to provide a representative basis for what

HAPs emissions would be". P159 at 17:23 (Sizemore). Thus, quarterly sampling does not result in HAPs limits that are practically enforceable. Id. at 19:5.

The Cabinet

794. The Cabinet urges that coal sampling is just part of the monitoring procedure for determining compliance with HAP limits. The primary method is proper operation of the control devices, which is covered by a variety of conditions. 4-14-04 TE at 75:11-17; 75:22-25 (Adams).

795. With regard to Petitioners' contention that coal sampling and annual stack tests are the primary method of determining compliance with HAP limits, Adams stated:

> The coal sampling is just – is just part of the monitoring procedure. I mean, the primary method for this permit is proper operation of the control devices, and that's certainly covered by a variety of conditions. You know, operation of the SCR, which is covered by a continuous emission monitor, operation of the particulate control devices, which are almost completely covered by a continuous opacity monitor, and I say that because I believe it's before the final wet scrubber, if I remember the location right, plus the periodic monitoring to insure the monitoring of the ESP. You know, since this hearing came up and we've looked at other permits, you know, I have noticed some states have gone to a monthly sampling. You know, that's their call. I don't think that it makes this permit any less enforceable. I mean, some have done more, some have done less, and we all seem to come up with professionals with an appropriate judgment. Id. at 107:11-108:7.

TGC

796. TGC urges that Petitioners' arguments regarding inadequate coal sampling are now moot as a result of Revision #2 (items 3 and 9) which clarify the required coal sampling to specify that TGS will take daily samples of the coal "as fired" and analyze these composites on a quarterly basis (i.e. daily samples composited quarterly).

797. In addition, TGC points out that coal sampling is only one of several permit provisions that ensure continuous compliance with the HAPs emissions limits, 4-14-04 TE at 77-

78 (Adams), and as acknowledged by Dr. Fox, 2-9-04 TE at 12, “monitoring for mercury and other HAPs consists of three parts – quarterly coal sampling, annual stack tests, and then a correlation of the annual stack test with the quarterly coal sampling and some operational parameters.” See Jt. #8 at B.3.a,e,f and B.4.m,n. Adams testified that TGS is one of the first permits to include the additional requirement that the facility regularly take and analyze coal samples to verify the HAPs content. 4-14-04 TE at 74-75. TGC urges that the quarterly coal samples are included primarily to provide further information to DAQ on the quality of the coal being used and to verify that the emission estimates used to set the permit limits are reasonable. 4-14-04 TE at 75-77 (Adams).

798. With regard to Petitioners’ claim that the permit is deficient because it lacks specific test methods for taking the coal samples and analyzing them, TGC urges that the regulations provide approved test methods to perform such activities. 401 KAR 50:015, Section 3, American Society for Testing and Materials (ASTM), which incorporates by reference ASTM Standards, including at subsection (1)(dd) D 3176-74 “Standard Method for Ultimate Analysis of Coal and Coke”). The permit also requires TGC to keep a record of its sampling methods so DAQ can verify that appropriate methods are used. Jt. #8 at 37.

Petitioners’ reply

799. In reply, Petitioners urge that the PC boiler HAP limits, found in Section B.2, p. 3-4. Jt. #8, are not enforceable as a practical matter because the permit does not include “appropriate monitoring” to demonstrate compliance, as required by 401 KAR 52:001, Sec. 1(31). 2-9-04 TE at 11:4-18:3 (Fox).

800. The permit indicates that compliance with the HAP limits will be demonstrated by a combination of methods: annual stack testing for all HAPS; annual coal sampling and

correlation with stack test for all HAPs; quarterly coal sampling for all HAPs except HCI (Hydrogen chloride); indicator parameters for VOC (HAPs), HC1, and HF (Hydrogen fluoride); and process operating conditions for all HAPs except HC1 and HF.

801. For the following reasons, Petitioners urge that TGC is incorrect in arguing that the permit contains multiple enforcement mechanisms that work together to ensure compliance with any given HAP limit: First, the only method that makes the applicable requirements enforceable is stack testing, which measures HAP emissions in the stack. Jt. #8, B.3.f. and B.3.g and p 7-8, Condition B.4.j. The indicator monitoring that provides secondary compliance assurance falls under the CAM (Compliance Assurance Monitoring) program, which does not make the underlying permit conditions enforceable. Second, each secondary method proposed to determine compliance with HAP limits contains a flaw, as listed below. Thus, the compliance methods in the permit do not yield "reliable data" for the HAPs limits, as required by Title V Manual, Sec. Ib.III(2).

a. Annual HAP limits are not enforceable because compliance cannot be established at any given time.

802. The HAPs – VOC(HAP), hydrogen chloride, arsenic, chromium, manganese, and cadmium – are only limited by an annual emission cap expressed in tons per year per unit. Jt. #8, p 3-4. The other HAPs – mercury, beryllium, lead, hydrogen fluoride – are limited by an instantaneous limit expressed in lb/MMbtu *and* an annual cap. Both types of limits are required to ensure enforceability, pursuant to the NSR Manual. Jt. #9, p B.56. EPA's position is that the longest averaging time generally acceptable for practical federal enforcement is one month. The initial test is not required until 180 days after initial startup. Jt. #8, p 5, B.3.f. Thus, the HAP

limits are not enforceable at least until the first stack test is conducted, about six months after startup, when relationships with indicators are established. 2-12-04 TE at 113:14-25 (Adams).

b. Annual stack tests are not enforceable

803. The permit requires demonstration of compliance with annual (ton/yr) and instantaneous (lb/MMbtu) MACT limits by annual stack testing. Annual stack testing is the only method that actually measures HAP emissions coming out of the stack. All other methods – quarterly coal sampling, coal quality correlation, process operating conditions – are indicators of stack HAP emissions. Annual stack tests are not adequate to assure continuous compliance with permit limits because one short-term stack test per year, a snapshot, is not enough to determine what the emissions are for an entire year, given the variability of HAPs in the coal. In addition, Petitioners urge that the stack test detection limits are too high. While the permit specifies EPA test methods (Method 26A, 29) to measure the HAPs in stack gases from the PC boilers, Jt. #8, p. 5, B.3.e, the permit does not state the analysis procedure that should be used where several are listed, as in Method 29, and does not require that a method be selected that is capable of measuring HAPs at levels below their permit limits. If the permittee chose an analytical method that cannot measure as low as the permit limit, it could fail to reveal a violation that was present but below the detection limit, 2-9-04 TE at 51:24-52:2-8; 2-11-04 TE at 113:9-114:15 (Fox), which Petitioners urge would render the applicable requirement unenforceable. 2-10-04 TE at 175:19-176:1 (Fox). This situation could be remedied by requiring the use of an analytical method with a known detection limit lower than the permit limit. 2-9-04 TE at 51-24-52:1-18 (Fox).

c. No correlation between annual stack tests and coal quality

804. One actual measurement (annual stack test) supplemented by three "estimates" (one sample of coal per quarter) is inadequate to determine continuous compliance with the HAP limits. The concentrations of HAPs in TGC's coal are highly variable. P98-4, P98-5, P99-8; 2-9-04 TE at 13:7-9; 20:8-9; 34:14-38:1, 150:6-7 (Fox). The coal quality is not constant enough to prove with one stack test per year and one sample of coal per quarter, or four samples per year, that a violation of a 30-day rolling average, quarterly average, or annual average limit occurred over the appropriate averaging time. 2-9-04 TE at 13:10-15:23 and 151:5-152:7 (Fox). Adams acknowledged that "there was a fairly detailed knowledge of coal quality that wasn't submitted with the application.", 2-9-04 TE at 98:1-4, which he said he would review after this process is over to determine if any changes are needed. 2-9-04 TE at 98:12-15. Also, the permit does not require that the stack tests be conducted under "maximum emissions potential", but rather only the "maximum production rate". Jt. #8, p 5, Sec. B.3.f.

d. Coal test method not specified

805. The permit and SOB do not specify a test method for the analysis of metallic HAPs in the coal itself. 2-9-04 TE at 81:15-23; 2-10-04 TE at 196:1-12 (Fox). Although TGC asserts that no permits exist that require HAPs compliance testing because "testing protocols are developed over time after equipment specifications and operating procedures are developed …", Petitioners state that relying on a protocol to identify test methods for the first time violates the Title V Manual, pg. 7, Sec. 1b(III)[71]. Although the record in this case contains reams of HAPs

[71] Title V Manual, Sec. 1b(III), Monitoring Requirements, provides:
1) The permit shall contain all emissions monitoring and analysis procedures and test methods that are specified in the applicable requirements, including those in 42 U.S.C. 7414(a)(3) or 42 U.S.C. 7661c(b).
2) If the applicable requirement does not require periodic testing or monitoring, the permit shall contain periodic monitoring sufficient to yield reliable data from the relevant time period representative of the source's compliance with the permit.

test data, the record contains no evidence as to why TGC can measure HAPs in its coal, but cannot specify a HAPs coal test method in its permit or in its proposed amendments. Petitioners note that the ASTM method cited by TGC does not identify a single HAP.

e. Grab samples are not adequate to enforce HAP limits

806. As discussed earlier, annual stack testing and quarterly grab sampling is the primary method to enforce HAP limits. Although Petitioners agree with Revision #2 (item #3) changing "grab" to "composite", they are concerned with the daily sampling and quarterly compositing scheme. This would still only result in four samples per year being analyzed. The proposed change does not identify the coal sampling method, the coal HAP test method, and does not modify reporting requirements, which only require quarterly recording of HAP analyses. Thus, the proposed TGC change does not make the HAP limits enforceable. They also note that "grab" sample is also called for in Condition B.5.g on p 5, which needs to be modified. The SOB also needs to be changed.

f. Quarterly coal sampling is not enforceable

807. The permit requires quarterly sampling of "as fired" fuel to the PC boilers for arsenic, beryllium, cadmium, fluorides, chromium, manganese, mercury, and lead, which would be "correlated" with annual stack test results to comply with the 30-day rolling average, quarterly average, and annual average emission limits. Jt. #8, Secs. B.2.h, B.2.j, B.2.k, B.2.1 and B.2.m, p 3-4. Quarterly sampling is not adequate to assure that HAP limits are federally enforceable, IDEM commented. The permit must require "periodic monitoring sufficient to

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3) Monitoring requirements shall be specified in the permit, which assure the use of terms, test methods, units, averaging periods, and other statistical conventions consistent with the applicable requirement. Recordkeeping provisions may be sufficient to meet this requirement.
4) The permit shall contain requirements covering the use, maintenance, and installation of monitoring equipment or methods.

yield reliable data from the relevant time period representative of the source's compliance with the permit." Title V Manual, p. 7,1b.III(2). Further, the CAM regulations require some data collection at least once per 24-hour period. Neither requirement is met.

808. The permit does not indicate whether the primary method of determining compliance with HAP limits is coal sampling, as Petitioners contend. The quarterly coal sampling provisions are found in three separate conditions and are confusing and overlapping. The conditions are: Jt. #8.p.5. Sec. B.3.g. – Jt. #8, p. 8-10 – and Jt. #8, p. 7, Sec. B.4.j. The only monitoring method that is potentially enforceable, because it measures stack emissions, is the annual stack test. All of the so-called secondary HAP monitoring methods combined are based on indicators to satisfy CAM requirements, which do not provide an enforceable mechanism for the emission limits. Because the permit is silent on how a violation of the HAP emission limits will be established, Petitioners urge that the permit is unenforceable.

809. Quarterly coal sampling coupled with monitoring of operating parameters is not adequate to determine compliance with the HAP limits due to variability of HAPs content of coal. 2-9-04 TE at 19:5-19, 84:25-86:23 (Fox). Annual to quarterly sampling is only acceptable when the underlying parameters are stable and do not vary. Quarterly coal sampling is also not adequate because the permit only requires that the control equipment be designed to meet about 98% control while most of the HAP emission limits (not including mercury) were calculated assuming 99.5 to 99.9% control. P171. Thus, these two factors – variability coupled with a mismatch in assumed control efficiency – lead to a reasonable presumption that HAP limits will be exceeded but the violations will go undetected, and thus unremedied, by the monitoring methods in the permit. 2-9-04 TE 148:23-152:7 (Fox).

h. Operating parameters are not enforceable[72]

810. Control system operating parameters do not make the underlying HAP limits enforceable because the permit does not state that an exceedance of the operating parameter range amounts to an exceedance of the HAP limits. 6-2-04 TE at 85:1-18 (Fox).

811. The control efficiencies, required at Jt. #8, p 13-14, Sec. B.7.e, are not enforceable to assure compliance with the HAP emission limits because the permit does not require testing to demonstrate that the required control efficiency is being achieved and because the permit only requires an "approximate" removal efficiency. 2-11-04 TE at 176:13 – 179:2 (Fox).

812. The permit fails to establish operating parameters for all of the equipment that controls HAPs, although operating parameters are required to assure compliance with the mercury limit. The permit only sets operational parameters on the wet FGD and the wet ESP. 2-9-04 TE at 15:24-17:8 (Fox).

813. The SOB does not contain any support or factual basis for the presumption inherent in permit condition B.4.m that process indicator parameters would assure compliance with the underlying HAP permit limits.

i. Indicator ranges and monitoring methods are not established

814. The permit fails to state that operation outside of a range constitutes a violation of the HAP limits, and even if the operating parameters were within the proper range, there could be an exceedance of the applicable requirement if, for example, the amount of mercury in the coal varied. 6-2-04 TE at 84-87 (Fox).

j. The permit does not require that a relationship be demonstrated

[72] I have included Petitioners' subparagraph "g" in "e".

between the operating parameter and HAP emission limits

815. The permit fails to require a study to demonstrate a relationship between emissions at the stack, and the indicator operating parameter. 2-9-04 TE at 17:22-18:19 (Fox); Jt.#9, p. H.7.

k. Recordkeeping is inadequate

816. The permit only requires that the permittee keep records of the indicator parameters which are monitored continuously, Jt. #8, p. 11, B.5.e, with only a summary of these records submitted to the Cabinet every six months, Jt. #8, p. 37, Sec. F.5, which conflicts with the requirement in the Title V Manual and permit that the permit be enforceable by citizens.

l. All regulated HAPs not included in CAM monitoring

817. The permit should have included CAM monitoring for all of the metallic HAPs listed in PD101-4.

m. The VOC (HAP) test method does not measure nonvolative organic compounds

818. The emissions from TGC will include nonvolative organic compounds, such as dioxins, which are not measured by EPA Methods 18 or 25, used to measure volative organic compounds.

Conclusions – On the issue of whether the HAP limits are enforceable

819. In brief summary, although Petitioners agree with Revision #2, item #3 (which would clarify that TGS is to take daily samples of the coal "as fired" and analyze these composites on a quarterly basis), they urge that the change does not make the HAP limits enforceable because the change does not identify the coal sampling method, the coal HAP test method, and does not modify reporting requirements, which only require quarterly recording of HAP analyses.

820. In addition, as set out above, the revision does not address numerous other reasons Petitioners urge for concluding that the HAPs limits are unenforceable.

821. I conclude that the HAPs limits are not enforceable, for the following reasons:

*Compliance cannot be established at any given time.

*Compliance cannot be established until the first performance test, six months after startup.

*One stack test per year, and three quarterly coal composite analyses, are insufficient to yield reliable data on continuous compliance given the variability of HAPs in the coal.

* The permit does not demonstrate the relationship between emissions limits and the indicator operating parameter.

* The permit does not establish acceptable operating ranges for the indicators.

Hence, on remand, I recommend the following revisions:

* The permit should indicate the primary method of determining compliance with HAPs limits.

* A HAPs coal test method, sampling procedure, and analysis procedure should be identified in the permit.

* The test method should be capable of measuring HAPs at levels as low as the permit limits.

* More than four analyses of coal samples should be required and should be recorded more frequently than quarterly.

* All control system operating parameters should be identified.

* The permit should state how monitoring provisions are to be used and whether exceedance of the operating parameter amounts to an exceedance of the HAPs limits.

822. Although Adams stated with regard to a question about (PM) test methods, "it's up to the source to make sure testing is done in such a method that they show compliance, not up for the permit review to know four or five years in the future what the test method – the subtest

methods, the exact option under the testing schemes that can be done", 4-14-04 TE at 118, his opinion is in conflict with the Title V Manual. The Manual, which is incorporated by reference in 401 KAR 52:020, very clearly states at 1b, III, 1, that the permit shall contain all emissions monitoring and analysis procedures and test methods. This does not contemplate that a testing protocol will be developed in the future, but instead requires that the test method and analysis procedures be a part of the permit. Dr. Fox's testimony demonstrates the problems that can be encountered if choosing a method is discretionary and a method is chosen which does not detect a limit as low as the permit limit.

B. Numerous monitoring requirements are missing from the permit and are only set out in the SOB.

Petitioners

823. Petitioners point out that the following compliance provisions are provided only in the SOB, which is not an enforceable document, and are required to be in the permit by the Title V Manual, 1b(III)3.

PM test methods for PC boilers
Annual PM performance testing for PC boilers
Annual VOC performance testing for PC boilers
VOC test methods for PC boilers
Cooling tower compliance testing
Annual PM performance testing for auxiliary boiler
Annual PM test methods for auxiliary boiler

TGC

824. TGC states that in order to make certain that the Permit is crystal clear, it submitted a minor permit revision to address all of these issues.

Conclusions – On the issue of whether there are numerous monitoring requirements missing from the permit and only set out in the SOB?

825. In light of TGC's acknowledgement that Revision #2 addresses all of the issues Petitioners raise with regard to compliance provisions which appear only in the SOB, I conclude that the permit should be so revised to the extent any of the above compliance provisions appear only in the SOB and not in the permit.

C. VOC limits are not enforceable

Petitioners

826. Petitioners incorrectly state that both the permit and SOB require only an initial source test for VOCs. A correction is made in Petitioners' reply, which points out that while the

permit specifies a single initial compliance test for VOCs, Jt. #8, p. 4, Sec. B.3.a., the SOB specifies both an initial source test and annual stack tests. Jt. #7 at 26.

Cabinet and TGC

827. Both the Cabinet and TGC point out that Section B.2.g of the permit requires compliance with the VOC limit to be demonstrated by compliance with the CO limit (i.e. CO is a surrogate for VOC). Jt. #8 at 3. Compliance with CO is demonstrated through, among other things, the use of a CEM (continuous emissions monitor). Jt. #8 at 7 (permit condition B.4.f). Thus, TGC urges that the CO CEMS is a parametric indicator for compliance with the VOC emission limit.

Petitioners' Reply

828. Petitioners state that the CO indicator approach would be enforceable, but they urge that one initial stack test for the PC boilers is inadequate to establish a relationship between CO and VOCs which would be valid over the life of the facility, given the variability of the coal. Thus, Petitioners urge more frequent stack tests and also urge that the permit should clarify that an exceedance of a CO indicator range constitutes a violation of the VOC limit. Petitioners also note that the test method, either Method 18 or 25, is listed only in the SOB and should be listed in the permit.

829. Petitioners point out that because Respondents did not respond to their argument regarding auxiliary boilers and the need for more than an initial performance test and the failure to identify any test methods, they should prevail on their argument as to the auxiliary boilers.

Conclusion – On the issue of whether the VOC limits are enforceable

830. The Title V Manual clearly requires that the permit is the document which shall contain all emissions limits, monitoring and analysis procedures, and test methods. Given the

variability of the coal, I agree with Petitioners that more frequent stack testing (not just an initial stack test) should be required to confirm the relationship between CO and VOCs and should be in the permit. The permit should also specify the test method.

831. Because Respondents do not provide any reason why these requirements should not also apply to the auxiliary boiler, these should also be added to the permit.

D. The public does not have access to the standard operating procedures (SOPs) that are used to determine compliance

Petitioners

832. Petitioners urge that the permit is not enforceable because the public did not have access to the SOPs or manufacturer's specifications for the FDG, SCR, ESP and WESP during the permitting process and will not have access to these items once TGS begins operation. In re: Cargill, Petition IV-2003-7 (US EPA July 16, 2004), supra.

Cabinet

833. The Cabinet urges that its inspectors have access to the information they need to determine compliance. Jt. #8, p 37, F3.

TGC

834. TGC points out that as discussed in Count 2, under Kentucky's combined PSD/Title V/Acid Rain permit program, where a single permit governs the construction of the facility as well as its subsequent operation, general language appears in the permit requiring the facility to maintain its equipment according to manufacturer's specifications and SOPs, which by necessity are developed after construction. 2-19-94 TE at 158-59 (Andrews). After the facility is constructed and operating, DAQ re-evaluates the required monitoring to ensure the permit reflects appropriate operating parameters. 4-15-04 TE at 90-91; 4-16-04 TE at 47 (Adams).

Even though Kentucky's permitting scheme limits the availability of the information Petitioners desire prior to construction, DAQ included other measures in the permit that allow for its enforcement. Permit Section F requires TGC to report exceedances from any permit requirement within 30 days. Jt. #8 at F.8., which also requires TGC to submit semi-annual monitoring reports to DAQ. Excess emissions due to unexplained shutdowns or malfunction must be reported promptly, and TGC must also submit annual compliance reports. Id. at pg 37-38.

835. With regard to Petitioners' reliance on In re Cargill, an EPA's administrator order, the emissions unit at issue in Cargill had been operating for nearly 22 years, and thus, appropriate SOPs and manufacturers' specifications were readily available. Here, however, under Kentucky's combined permitting program, it is not possible to provide such information at this point because the information does not yet exist. 4-14-04 TE at 108-09 (Adams).

Petitioners' Reply

836. In reply, Petitioners urge that since the permit relies on following maintenance and operating procedures, the permit must disclose with specificity what those procedures are. Petitioners argue that even with Kentucky's combined construction and operating permit program, it was feasible to establish maintenance and operation procedures before the permit was issued because they state that the required information did exist before the permit was issued, as shown by confidential exhibits, PCBI-137-123 and PCBI-137-119.

837. In addition, they urge that TGC's engineers could have prepared maintenance and operating procedures for the proposed equipment. Petitioners also urge that the reporting procedures in the permit do not make up for lack of maintenance and operating procedures.

Conclusion – On the issue of whether the public is required to have access to the standard operating procedures (SOPs) that are used to determine compliance

838. I do not agree that the permit is unenforceable because the SOPs and manufacturer's specifications are not included in the permit. As explained, Kentucky's combined permitting program is distinguishable from the situation in Cargill where the emissions unit at issue had been operating for almost 22 years and the SOPs and manufacturers' specifications were readily available. Under Kentucky's program, the information which Petitioners seek is not available, except in confidential business information. Indeed, design details remain to be completed because neither construction nor operation has begun. As stated by Respondents, however, the permit includes general language requiring the facility to maintain its equipment according to manufacturer's specifications and SOPs. 2-19-04 TE at 158-59 (Andrews). After the facility is constructed and operating, DAQ re-evaluates the required monitoring to ensure the permit reflects appropriate operating parameters. 4-15-04 TE at 90-91 (Adams).

E. The monitoring for PM is not enforceable as a practical matter

839. The permit sets a "particulate emissions" limit from the PC boilers of 0.018 lb/MMbtu on a 3-hour average. The permit sets a limit of 0.06 lb/MMbtu on "particulate emissions" from the auxiliary boiler. Jt. #8, p. 15, B.2.a. Compliance with the PC boiler limit is to be determined by annual stack tests, monitoring opacity as an indicator, and monitoring operating parameters of the dry ESP and wet ESP as indicators. Jt. #8 at B.4.b),c) and l). 6-2-04 TE at 72:3-17 (Fox). Compliance with the auxiliary boiler limit is determined only by stack tests. Jt. #8 at 16-17.

840. All parties now agree that the particulate matter limit for the PC boilers is BACT, as a result of item #7 in Revision #2, which states that the PM limit for the PC boilers is set on total PM and total PM_{10}, both comprising the sum of filterables (front half) and condensables

(back half). Also, Revision #2, item #8, clarifies that annual PM stack tests are required, during which all parameter ranges will be verified using the type of coal being burned at that time.

Petitioners

841. Petitioners state that the indicator parameter operating ranges for PM are to be determined during initial operation, when the facility is burning Seam 9 coal. However, when TGC switches to a blend of fuels, Petitioners argue that none of the relationships will be valid. Nothing requires that these relationships be revised when coal quality changes even though coal changes often effect PM emissions and the performance of the ESP.

Respondents

842. Both Respondents urge that this is an entirely new argument raised in Petitioners' brief. (In their reply brief, Petitioners point out that they raised this in rebuttal in response to claims by Respondents that the PM indicator monitoring was enforceable. 6-2-04 TE at 76:12-77:7 (Fox)).

843. TGC points out that Petitioners cite no evidence showing that a switch to a Seam 9/Seam 8 coal blend would change the relationships for the PM parameter ranges. TGC also points out that the permit requires a continuous opacity monitor (COM) to ensure continuous compliance with the PM limit. Jt. #8 at B.4.a. The permit and regulations authorize DAQ to perform or require TGS to perform a stack test at any time to verify compliance. 401 KAR 50:045, Sections 1, 2; Jt. #8 at B.3.c.

Petitioners' Reply

844. The PM/PM_{10} limits are not enforceable for four reasons: 1) the regulated pollutant is not clear; 2) the proposed stack testing, the only method that actually measures emissions from the stack, is not adequate to assure continuous compliance; 3) the use of

operational parameters as an indicator for PM emissions violates regulations and is not adequate to assure continuous compliance; and 4) the use of opacity as an indicator of PM emissions violates regulations and is not adequate to assure continuous compliance. TGC's proposed revision attempts to cure the first two issues.

Reason one - This issue is now resolved by Revision #2, item #7. This same ambiguity should be corrected for the auxiliary boiler, Petitioners urge.

Reason two - The permit does not list any test methods, beyond citing a regulation that contains a laundry list of methods, which is contrary to the Title V Manual, p 7, Sec. 1b(III). The SOB does list test methods[73] but further confuses the matter, classifying the PM limit as applying to PM/PM_{10} for BACT and then listing the regulated pollutant as PM (rather than PM/PM_{10}), but providing a list of test methods that include the components of total PM and total PM_{10}. 2-10-04 TE at 179-187 (Fox). Petitioners ask how "this smorgasbord of test

[73] The SOB, Jt. #7 at pg 26, cites Methods 5 (filterable PM), 9 (opacity), 201 (filterable PM_{10}), or 201A (filterable PM_{10}), & 202 (condensable PM/PM_{10}). In other words, the SOB does not cite Methods 5 and 17.

methods" can be used to determine compliance with the PM limits. Adams conceded: "I do not disagree that the language in this permit needs to be tweaked for the PM test methods." 4-14-04 TE at 118:1-3. Only the SOB lists PM test methods for the auxiliary boiler.

845. Petitioners urge that annual testing for the PC boilers (item #8 in Revision #2) is not adequate to demonstrate compliance with the PM/PM_{10} limits, given the deficiencies in the "secondary" methods of compliance documented elsewhere in their brief and given that PM is highly variable. 2-9-04 TE at 20:16-21:13; 6-2-04 TE at 79:12-17 (Fox). A particulate matter stack test consists of three 1-hour runs, which Adams acknowledges was not "robust". 4-16-04 TE at 62:23-24.

846. Petitioners point out that neither the permit nor the SOB contain support for choosing opacity as an indicator of PM/PM_{10} emissions expressed in lb/MMbtu. While the permit proposes to establish a correlation between opacity and PM during an initial stack test, Dr. Fox testified that the opacity indicator monitoring is structured so that it is nearly impossible to detect an exceedance of the PM limit. 6-2-04 TE at 74:12-15; 6-3-04 TE at 132:13-133:12. While it is not feasible for TGC to develop a correlation between opacity and the PM emission limit for a facility that does not yet exist, it is feasible to present relevant data from similar operating facilities or to lay out the details of a test plan to develop the relationship. Second, the permit contains no requirement to revisit the correlation between opacity and PM following the initial stack test if the fuel changes, equipment is updated, or operating modes change. Third, the relationship between PM and opacity is established during "representative" and likely optimized and idealized conditions. Fourth, even during "representative" conditions, the correlation between opacity and PM is not necessarily good and must be demonstrated. Fifth, a five percent opacity fudge factor is added on top of the measured opacity-PM relationship. The fudge factor

should be eliminated unless the maximum PM emission rate is substantially lower than the upper end of the opacity range. Sixth, if the generous trigger is exceeded, the exceedance only triggers an inspection. Seventh, stack testing to confirm compliance with the PM limit only takes place after the trigger test is failed more than five percent of the time. This is clearly not enforceable as it allows the facility to operate for extended periods of time at opacity levels that on their face represent exceedance of the underlying PM limits. Eighth, the condition exempts periods of startup and shutdown. Ninth, the condition was developed before it was recognized that the regulated pollutant is total PM/PM_{10}. Tenth, the EPA in the preamble to its performance standard for PM CEMS concluded that for rules that establish PM emission limits, it believes that PM CEMS are the appropriate technology for compliance monitoring. CabR32, p 1790-1791; 6-2-04 TE at 75:8-20; 5-3-04 TE at 112:17-25 (Fox and Adams).

847. Next, Petitioners urge that the COMs (continuous opacity monitor) is located in the wrong place (it is after the dry ESP and before the wet FGD). The opacity indicator method proposes to correlate PM emissions in the stack with opacity measured upstream of the wet FGD because the stack is wet. 2-9-04 TE at 21:8-21 (Fox); 2-12-04 TE at 105:5-11 (Adams); 4-22-04 TE at 120:10-20 (Adams); 6-2-04 TE at 78:20-79:15 (Fox); Jt. #8, pg. 9, B.4.5. Petitioners urge that this location is not necessary because COMs have been developed since NO_x NSPS at 40 CFR 60, Subpart Da was promulgated, which allow accurate opacity measurements in wet stacks. 2-10-04 TE at 207:18-21; 2-11-04 TE at 117:2-5 (Fox). The proposed location for the COM voids the use of opacity as an indicator for PM emissions at the stack because it is in the wrong place for use as an indicator. 2-9-04 TE at 22:5-12 (Fox).

<u>Reason three</u> - The permit proposes the use of control equipment operating parameters as a secondary check on PM emissions. The proposed parameters are the dry ESP and wet ESP

(WESP) electrical fields, i.e. voltage. Jt. #8, p. 8-11. Petitioners urge that this condition is not enforceable for four reasons: 1) the permit does not establish acceptable ranges for the voltages of the ESPs, nor a method to determine that range; 2) the record contains no support for the assumed relationship between just voltage and proper operation of the ESPs; 3) the permit does not require monitoring of operating ranges of all of the devices that control PM; and 4) this type of indicator monitoring, even when correctly specified, is not adequate to render the emission limit enforceable, because the permit limit is specified in terms of pounds of particulate matter per million BTUs of fuel burned based on a 3-hour average, not in terms of instantaneous ESP voltage. In sum, indicators cannot be used to prove a violation unless the permit explicitly states that an exceedance of the indicator range constitutes a violation of the applicable requirement (which it does not state).

<u>Reason four</u> - Although the permit requires four methods to determine compliance with the PM/PM_{10} emission limit: stack tests, opacity surrogate monitoring, operating parameter monitoring, and visual observation, Petitioners maintain that the record contains no support for the underlying assumption that a visual observation of the stack at the proposed frequency would reveal anything about the PM/PM_{10} emissions in lb/MMbtu.

Conclusions – On the issue of whether monitoring for PM is enforceable as a practical matter

848. The enforceability of the PM limit relies on three factors: 1) a relationship between PM and opacity determined in source tests, as measured by a COM; 2) periodic source tests; and 3) monitoring operational parameters on some of the PM control equipment, such as ESPs. Based primarily on the testimony of Dr. Fox and Adams, I conclude that the PM limits are not enforceable, and I make the following recommendations:

1) The regulated pollutant should be corrected for the auxiliary boiler, as Revision #2, item #7, did for the PC boilers.

2) The permit should list test methods for PM/PM_{10} for the PC boilers and the auxiliary boiler. The test methods in the SOB need to be clarified so that the regulated pollutant is consistently identified.

3) Annual testing for the PC boilers is not adequate.

4) On remand, TGC should be required to present a test plan to develop the relationship between opacity and PM; to revisit the relationship if the fuel changes, equipment is updated or operating modes change; the 5% opacity fudge factor should be eliminated unless the maximum PM emission rate is substantially lower than the upper end of the opacity range; TGS should not be allowed to operate for extended periods of time at opacity levels that represent exceedance of the underlying PM limits; and periods of startup and shut down should not be exempted.

5) On remand, the location of the COMs should be changed as a result of testimony showing that COMs now allow accurate opacity measurements in wet stacks. 2-10-04 TE at 207:18-21; 2-11-04 TE at 117:2-5 (Fox).

6) PM control equipment operating parameters are inadequate for reasons cited by Petitioners. On remand, DAQ should reassess the parameters, and the permit should provide that an exceedance of the indicator range constitutes a PM violation.

F. The permit lacks monitoring and reporting to make the emission limits for the material handling units (emission units 4 – 9) enforceable as a practical matter

Petitioners

849. Petitioners state that although the permit contains emission limits and work practices for the six material handling units (emission units 4 and 5 - coal handling systems; 6 - coal piles; 7 - FGD reagent prep handling; 8 - FGD reagent prep handling (fugitives); and 9 - fly ash handling system), it lacks monitoring and recordkeeping to ensure the BACT limits. Jt. #8 at 19-31. Petitioners give the following examples: a) even though the coal handling system emission unit must exhibit a particulate design control efficiency of at least 99%, there is no requirement to test the control efficiency of these baghouses; b) with regard to units 5, 6 and 8, which are prohibited from discharging visible fugitive dust beyond the property line, there is no monitoring of this standard; and c) unit 7 contains a particulate matter emission limit, but there is no requirement to test to demonstrate compliance at any regular interval.

Cabinet

850. The Cabinet responds specifically, as follows:

With regard to baghouse emissions, the permit provides that the baghouse shall be maintained and operated in compliance with applicable requirements of 40 CFR 60, Subpart Y (a national source performance standard). Jt. #8, p. 21, Sec. B, 7a, Unit 4. With regard to coal handling generally, the permit provides that a qualitative visual observation of the opacity of emissions from each emission unit is to be performed on a weekly basis by the permittee. Id.. at 20, Sec. B.4.

With regard to units 5, 6 and 8, they are prohibited from discharging visible fugitive dust beyond the property line, pursuant to the citation of 401 KAR 63:010 (fugitive emissions) in the permit.

With regard to unit 7, the permit provides for compliance with 401 KAR 60:670 and 40 CFR 60.675(b)(1), which require that EPA Reference Method 5 or 17 be performed to determine compliance. Id. at 27, Sec. B, 3b.

851. The Cabinet urges that Petitioners have not shown that these provisions are insufficient. In addition, the Cabinet points out that TGC is under an ongoing obligation to "maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions." 401 KAR 50:055.

TGC

852. TGC points out that the permit contains numerous monitoring and recordkeeping requirements for each of these units. Jt. #8 at pg 20,27, 31. If visual emissions are observed, then Reference Method 9 must be used to determine opacity emissions and TGS must inspect the control equipment, and in addition, TGS is required to record the results of its visual observations and any compliance testing performed. Id. Several of these units are subject to the requirements of 40 CFR Part 60, Subparts Y and OOO (incorporated by reference in 401 KAR 60:005). See Jt. #8 at pg. 19, 26. Both of these subparts, which are applicable to TGS's material handling operations, contain specific emission standards for fugitive PM emissions. 40 CFR

Section 60.252(c), 60.672. Both subparts also designate specific monitoring methods to ensure compliance with the standards. 40 CFR Section 60.254, 60.675.

853. Also TGC points out that the permit requires TGC to install and operate various types of control devices to reduce emissions from these emission units, Jt. #8 at p. 22-25, 28-29, and to maintain and operate the equipment to ensure these units comply with fugitive emissions requirements under 401 KAR 63:010. 4-14-04 TE at 114 (Adams). TGS is required to take "reasonable precautions" to prevent fugitive PM emissions, 401 KAR 63:010, Section 3, and TGS is also required to maintain records of the fugitive monitoring, operations and maintenance on the control equipment. Jt. #8 at 23, 25, 29. TGC urges that given the level of DAQ's technical expertise in this area, deference is especially appropriate here.

Petitioners' Reply

854. In reply, Petitioners urge that unless the permit requires that emissions are to be monitored, with the results recorded and reported, the general maintenance and operation practices cited by Respondents are not enforceable. Title V Manual at p. 6, Sec. 1b (III)(2) requires "if the applicable requirement does not require periodic testing or monitoring, the permit shall contain periodic monitoring sufficient to yield reliable data from the relevant time period representative of the source's compliance with the permit."

855. In sum, Petitioners cite three reasons why the qualitative provisions TGC cites are not adequate to demonstrate compliance with BACT: 1) control efficiencies are not listed; 2) no methods are listed to determine a relationship between a monitored operational parameter and underlying emissions; and 3) no explicit statement is included that an exceedance of an operational limit constitutes a violation of the permit limit. 2-9-04 TE at 44:7-17 (Fox); see EPA Comment 7, Jt. #44 at Red 21.

Conclusions – On the issue of whether the permit's lack of monitoring and reporting make the emission limits for the material handling units (emission units 4 – 9) unenforceable as a practical matter

856. When Dr. Fox was asked about the adequacy of the permit with respect to materials handling operations, she responded:

> There are at least two of the units for which there is – there are no permit limits or testing required on coal handling unit 5 and the coal storage plant….
>
> There should have been a PM_{10} or an opacity limit and a requirement for periodic testing of opacity. Instead there's a specific monitoring requirement in Section 4, on page 23, which has all the flaws that we've talked about previously: For operational parameters, no ranges specified, no method to determine whether there's a relationship between the monitored operational parameter and underlying emissions, and no explicit statement that – if an operational limit, once established, is exceeded constitutes a violation.
> 2-9-04 TE at 43:17 – 44:17

I conclude that the qualitative practices which Respondents rely on are inadequate to maintain BACT for the materials handling units. TGC should be required to comply with the monitoring and recordkeeping requirements of Title V Manual at pg. 6, Sec. 1b III and IV.

Additional enforceability issues

857. The following enforceability issues were not included in the six issues raised in Petitioners' posthearing brief. They were raised only in Petitioners' reply brief. Thus, Respondents did not have an opportunity to respond to them. For this reason, I will not consider them.

a. Emission limits during startups and shutdowns are not enforceable
b. Liquid fuel activities are not enforceable
c. Cooling tower limits are not enforceable
d. The absence of emission caps makes the permit unenforceable
e. CEMS compliance is ambiguous

<u>Count 17 – Errors and Omissions</u>

Count 17 - Findings

Overview

858. This Count involves alleged errors and omissions in the permit, which Petitioners urge make the permit unenforceable.

859. Although TGC and DAQ acknowledge that there are certain errors and omissions in the permit which need to be corrected, they do not agree that the errors and omissions render the permit unenforceable.

860. As stated in Count 14, following the formal hearing, TGC submitted to DAQ a list of proposed administrative amendment/minor permit modifications to address some, but not all, of the items in Counts 14 and 17. Docket #299. On February 17, 2005, the Cabinet issued Revision #2 in response to TGC's proposed permit amendments. The items in Revision #2 are listed in the Findings for Count 14. On March 21, 2005, Petitioners filed a petition to contest Revision #2 with regard to the permit revisions which they had objected to at the time they were filed. By Agreed Order of the parties, filed on April 19, 2005, the claims raised by Petitioners shall be considered in this Report as part of File Nos. DAQ-26003-037 and DAQ-26048-037. Docket #339.

861. As stated in Count 14, where all parties agree with an item in Revision #2, any issue dealing specifically with that item is now moot.

General Findings

862. The Findings of Fact enumerated for Count 14 are applicable to Count 17.

Count 17 - Parties' Arguments Followed by Conclusions

Petitioners

863. Petitioners urge that there are six errors or omissions which are "material" and require amendment of the permit. Petitioners then cite 27 more bulleted items which they state need to be clarified or corrected. Petitioners also list four additional permit conditions which they urge need to be changed.

864. The Cabinet, in an attempt to simplify this Count, has presented in its post hearing brief an "Index for Count 17 Allegations", listing Claim A – Claim Ab. The basis for the index is PD190-21 (Petitioners' Supplemental Answer to Interrogatories, filed October 8, 2003), which Petitioners' counsel on April 15, 2004, stated was the final statement of Petitioners' claims on the errors and omissions in the permit. The Cabinet points out that PD190-21 did not include two items – Bulleted items 5 and 15 - which Petitioners had listed earlier in their Memorandum in support of Petitioners' Motion for Summary Judgment, CABD-023, and which do not appear in Petitioners' post hearing brief. For this reason, the Cabinet urges that I not consider any arguments which may appear in Petitioners' *reply* brief as to these two bullets. These two bullets and the Cabinet's response (set forth in its response to Petitioners' Motion for Summary Judgment, P200) follow:

> Bulleted item 5 - Permit Condition B(4)(c) requires monthly qualitative visual observation of the opacity of emissions while Permit condition B(4)(1) requires weekly stack observations.

> Cabinet Response to Bulleted item 5 – This is not an inconsistency or error. The conditions in B(4)(c) are summarized in the table following B(4)(1). However, the conditions noted in the table following B(4)(1) do not elaborate on the monitoring scenario which is fully explained in B(4)(c). The monitoring scenario in B(4)(c) provides that if, during a monthly qualitative visual observation of emissions some opacity is noted, then Observation Method 9 must

be performed, and if opacity is determined to exceed 20%, then a Method 9 observation must be conducted on a weekly basis until the problem is corrected.

Bulleted item 15 – The SOB, Table 5.2, indicates that mercury would be controlled by 'scrubbing and baghouse' while the Permit, pg. 2, indicates that a baghouse would not be used.

Cabinet's Response to Bulleted item 15 – We at the Division acknowledge that the phrase "scrubbing and baghouse" was copied from a previously drafted document and pasted into the Statement of Basis for the Thoroughbred permit without deleting the words "and baghouse", as was the intent of the Division. The Division will address this typographical error through an administrative amendment. (The Cabinet will amend the SOB).

865. In its post hearing reply brief, Petitioners adopt the Cabinet's labeling of Petitioners' claims under Count 17, and Petitioners present a table enumerating these claims and stating their positions on each claim. I have taken this table, labeled Count 17 Table, and to the best of my ability I have stated the parties' positions on each claim as reflected in their post hearing briefs. This table is found in Appendix 5 to this Report. I note that because TGC's post hearing brief was filed at the same time as the Cabinet's post hearing brief, TGC did not have the benefit of the Cabinet's labeling system. However, I have attempted to identify TGC's position on each claim under Count 17, and I have added it to the table.

866. Revision #2 addressed Claims C, D, H, Aa, E, B, F, G, J, I, O, W and M (as labeled by the Cabinet in its Index and adopted by Petitioners in their table). Thus, as stated earlier, these claims are now moot.

867. Claims which were not included in Revision #2 are: Claims A, D (in part), K, L, N, P, Q, R, S, T, U, V, W (in part), X, Y, Z, and Ab. An explanation of these claims in the Count 17 Table are listed below, with my Conclusions.

Claim A – Chromium limit – The question is whether the chromium limit should be 0.3419 ton/yr or 0.3149 ton/yr. TGC urges that the correct emission rate is .3419 ton/yr. The Cabinet and Petitioners both suggest that the issue needs review.

Conclusion: On remand, DAQ should review this issue.

Claim D - The question in the second part of Claim D is whether the second constant in the SO_2 equation should be changed from 1.96 to 1.645 to correspond to a 95% single-sided confidence limit.

Conclusion – On remand, DAQ should review this issue.

Claim K - The question is whether the inconsistency between the SOB and permit should be clarified, i.e. the SOB indicated only an initial performance test would be conducted for mercury while the permit requires annual performance tests.

Conclusion: DAQ should make this clarification.

Claim L – The question is whether the inconsistency between the SOB and permit should be clarified, i.e. the SOB, p. 12, indicates no compliance testing for HF. The SOB, p. 27, indicates an initial performance test for HF, Be and Hg. The permit, Condition B(4)(n), p. 10, requires annual performance tests for all HAPs, while the permit, Condition B(4)(1), p. 8, requires only an initial source test for HF and thereafter the use of a correlation with SO_2.

Conclusion: DAQ should review this issue.

Claim N- The question is whether the permit condition which allows TGS to switch from No. 2 fuel oil to natural gas for startup if and when it becomes available at the site, without having to reopen the permit, is error. Petitioners presented no evidence on this claim.

Conclusion: No amendment required.

<u>Claim P</u> - The question is whether clarification is required on the air quality analysis on less than 40% loads.

Conclusion: DAQ should review this issue for possible amendment.

<u>Claim Q</u> – The question is whether DAQ should state in the SOB where it obtained Table 5.2, ranking control technologies in the BACT analysis.

Conclusion: On remand, DAQ should correct this error.

<u>Claim R</u> – The question is whether the 3-hr and 24-hr Class I SO_2 increments are inadvertently reversed in the SOB. Adams acknowledges that there is an error; the 24-hr increment should read 5 $\mu g/m^3$ and the 3-hr increment should read 25 $\mu g/m^3$. Petitioners agree that this is error, but they state that the 24-hr increment is 4.98 $\mu g/m^3$. TGC acknowledges the error, but states that it is irrelevant to the permit.

Conclusion: On remand, DAQ should correct this error and state that the 24-hr increment is 4.98 $\mu g/m^3$.

<u>Claim S</u> - The question is whether there is a discrepancy between the SOB emission summary and the application. In the SOB, Table 3.1, the NO_x emissions are reported as 6,029 ton/yr, while the Addendum reports NO_x emissions of 6,030 ton/yr. SOB, Table 3.1 reports H_2SO_4 emissions as 326 ton/yr, while the Addendum reports H_2SO_4 emissions as 324 ton/yr.

Conclusion: On remand, DAQ should correct the typos in the SOB.

<u>Claim T</u> – The question is whether the annual emission caps in the SOB, Tables 3.1 and 4.1, should be in the permit to assure that emissions are maintained below those assumed in the air quality analyses.

Conclusion: No amendment is needed because the emissions limits are based on the facility operating at 8,760 hours per year, the number of hours in a year.

<u>Claim U</u> – The question is whether the permit should contain an annual emissions cap based on annual averages, not 30-day or shorter averaging periods.

Conclusion: No amendment is required because the regulations do not require annual emission caps.

<u>Claim V</u> - The question is whether the permit should contain the requirement in the SOB, p. 14, that "coal sulfur content would be a direct indicator of expected sulfuric acid uncontrolled emissions, which would then be correlated to CEM SO_2 results to determine compliance."

Conclusion: No amendment is needed because the requirement is in the CAM section on p. 8 of the permit.

<u>Claim W (second part)</u> - The question is whether there is a difference between 0.0005% drift eliminators (high efficiency) and 0.002% drift eliminators (standard) in the cooling towers.

Conclusion: DAQ should review this issue.

<u>Claim X</u> – The question is whether the SOB should be revised to reflect that the FGD does not control either HF and H_2SO_4.

Conclusion: No revision is needed because both HF and H_2SO_4 reach to a limited degree in a wet FGD.

<u>Claims Y and Z</u> -The question is whether the permit should be amended because the VOC emission limit is lower than the limit guaranteed by ALSTOM and whether the CO BACT emission limit should be changed because it is greater than the level guaranteed by ALSTOM.

Conclusion: No revision is needed because an applicant can choose a limit lower than a vendor guarantee, and there no inherent wrong in choosing a limit higher than a vendor guarantee.

<u>Claim Ab</u> – The question is whether criteria pollutant emission limits apply during start ups and shut downs.

Conclusion: No revision is required because BACT limits apply at all times.

Count 18 - HAP Emissions estimates

Count 18 - Findings

Overview

868. Petitioners allege that the basis for the calculations used to derive the HAP emissions in tons per year for the two PC boilers is not in the record the Cabinet considered prior to issuing the final permit, in violation of 401 KAR 52:020 Section 5(3)(g) and (j), which require that applications shall contain emission rates in tons per year and in terms necessary to establish compliance consistent with the applicable standard reference test method, and calculations upon which the information in this paragraph is based.

869. The Cabinet urges that Petitioners failed to carry their burden of proof on this Count because they did not show that if the HAP calculations were done differently, they would show that TGC will violate its HAP emissions limits.

870. TGC urges that DAQ had all the information necessary to make a reasoned decision as to the HAP emission limits.

871. In reply, Petitioners urge that because of errors, omissions, and inconsistencies in supporting information it is not possible to infer, derive or back calculate the HAP emissions with the information the Cabinet had prior to permit issuance. Moreover, Petitioners urge that the regulations require forward calculation, i.e. the process of deriving the answer.

General Findings

872. TGC acknowledges that it did not provide DAQ with the basis for calculations used to derive the HAP emission limits, which are summarized in P101-4, p. 6-7, and Jt. #57 at Red 241 and 242.

873. The information which TGC submitted, which it urges was all that was necessary for DAQ to estimate HAP emissions, is listed below:

a. February 2001 boiler POC (Pollutants of Concern) table – Jt. #61 at Red 297 (controlled and uncontrolled emissions estimates for mercury, beryllium and lead based on coal quality data (ultimate analysis, trace metals, and heat content)) from the nearby mine and AP-42[74] emission factors when coal quality date was unavailable.

b. Revised October 2001 permit application - POC table for HAPs (emission factors, coal usage, heat rate and controlled emissions estimates) – Jt. #57 at Red 236

c. Coal quality data for Western Kentucky Seams 8 and 9 coal upon which the emissions estimates in the October POC tables were based. Jt. #56, Att. 2 at Red 42-44

d. Supporting information (analogous coal content, additional removal efficiency information) on HAP emissions estimates in the case-by-case MACT analysis. Jt. #44 at Red 7-8.

Count 18 - Parties' Arguments

Petitioners

874. Petitioners state that TGC's application did not contain the basis for the HAP emission calculations. Instead, the results of these calculations, reported in the "Pollutants of Concern" table, P101-4, became the HAP emission limits in the permit. Petitioners point out

that HAP emissions are calculated from the pollution control efficiency, the heat rate, and coal quality, among other factors. 12-3-03 TE at 85:17-25(Fox). Petitioners cite to the Cabinet's Final Determination and SOB for the Spurlock plant, P137-317, p 6, as showing the type of information that is typically provided to support emission calculations, and the level of detail which is required to support an emission rate. 12-3-03 TE at 88:25-89:3 (Fox). In contrast, Petitioners point out that TGC provided the supporting information and calculations for its HAP emissions in its prehearing memorandum, Attachment 9, in September 2003, after the permit was issued. 12-3-03 TE at 99:22-102:13 (Fox).

875. Petitioners point out that the MACT analysis, the permit and the SOB all claim that the HAP emissions and permit limits for non-mercury metallic HAPs is based on a 98% control efficiency. See, e.g., Jt. #8, permit, pg. 14 at Sec. B(7)(e); 12-3-03 TE at 95:17-96:7 (Fox). TGC's prehearing memorandum revealed for the first time that the emission rates and permit limits were calculated assuming much higher control efficiencies than 98:99.9% for arsenic, 99.5% for other HAPs. 12-3-03 TE at 102:24-104:8 (Fox). The record, however, contains no support for these high removal efficiencies. 12-3-03 TE at 103:4-8 (Fox).

Cabinet

876. The Cabinet urges that for the same reasons I granted TGC's motion for directed recommendation on Count 3 (wherein Petitioners alleged that TGC failed to demonstrate its emissions will not cause or contribute to a violation of NAAQS or increment consumption) (see Interim Report, Appendix 3**,** p. 6), I should conclude that Petitioners have not met their burden of proof on Count 18. The Cabinet points out that although Petitioners complain that they could not find the HAP emission calculations in the permit materials, they did not show that if the HAP

[74] AP-42 is EPA's bible for estimating emissions.

calculations were done differently they would show that TGC will violate its HAP emissions limits.

TGC

877. TGC urges that it provided all the information necessary for DAQ to estimate HAP emissions. 2-9-04 TE at 143 (Adams). TGC points out that Petitioners are arguing that because TGC did not include a sample calculation showing how to use the information submitted to derive the emissions estimates in the application, DAQ had no rational basis for the HAP emissions limits in the permit. However, DAQ possesses technical expertise to derive HAP emissions from the information submitted. 2-10-04 TE at 229-62 (Fox); 2-19-04 TE at 69 (Handy). Dr. Fox testified that the control efficiencies could be calculated from the information provided to DAQ. See TGC210 at 1-2, Dr. Fox's affidavit, where she acknowledged that removal efficiencies for mercury and hydrogen fluoride can be calculated based on information provided in the permit application. While she suggested that TGC's submittals did not support assumptions necessary to calculate removal efficiencies for the other constituents, she acknowledged that the removal efficiencies could be calculated "using information on coal blend and heat rate submitted by TGS." Id. at 2. Both of these, however, can be derived from TGC's submittals. Heat rate is 7,443 MMbtu/hr (Jt. #57 at Red 236), and the 30/70 coal blend can be derived from the December 2001 response to comments' trace metal analysis (Jt. #56 Att. 2 at Red 42-44) and from the October 2001 POC table (Jt. #57 at Red 236); see 2-19-04 TE at 75, 80-81 (Handy). Finally, and most importantly, Dr. Fox admitted that P171 contains all the necessary information. 2-10-04 TE at 229 (Fox). Thus, TGC urges that the record reflects that all the removal efficiencies on the exhibit could be derived from information TGC submitted to DAQ. 2-19-04 TE at 69 (Handy).

878. With regard to Sizemore's testimony that she could not find the basis for the lead emissions, TGC points to the boiler POC table in Jt. #57 at Red 236, which includes the emission factor for lead in lb/MMbtu and the controlled and uncontrolled emissions in tons per year. The limits in the permit are based on this information. Jt. #8 at 3.

879. With regard to Petitioners' argument that DAQ lacked support for the non-mercury metallic HAP removal efficiency of 99.5+%, TGC points out that the record provides sufficient information in the POC table for DAQ to require this removal for the non-mercury metallic HAP emissions limits. See Jt. #57 at Red 236; P171; 2-19-04 TE at 69-71, 73-76 (Handy). Dr. Fox was in agreement that information was present to determine the non-mercury metallic HAP removal efficiency of 99.5+%. 12-2-03 TE at 133-34 (Fox).

Petitioners' reply

880. In reply, Petitioners urge that HAP emission calculations must be in the application. 401 KAR 52:020, Section 5, and Title V Manual, p. 14. As a result of the HAP emission calculations not being in the application, Petitioners urge that DAQ has issued a permit with HAP limits that are inaccurate and cannot be met. They also urge that the public was deprived of its right to review the permit and supporting material.

881. Petitioners argue that the regulations do not contemplate "back calculation" (referring to TGC's statement that "engineers testified … that HAP emissions could be derived from the information submitted"), but instead require forward calculation, which refers to the process of deriving the answer. Petitioners urge that the process of back calculation is "complex

and beyond the grasp of most of the public", as demonstrated by the difficulty Handy, Fox, and Tickner experienced in attempting to back calculate the HAP emissions.

882. In responding to TGC's allegations specifically, Petitioners argue that TGC misstated Dr. Fox's testimony and mischaracterized the record. In summary, Petitioners urge that the HAP emission calculations were not in the record before the permit was issued, and the testimony reveals that it is not possible to "infer, derive or back calculate them" with the information that was before the Cabinet prior to permit issuance because of the errors, omissions, and inconsistencies in supporting information.

Count 18 - Conclusions

883. I agree with Respondents on this Count. Even though TGC failed to provide the basis for the HAP calculations, as required by 401 KAR 52:020 Section 5(3)(g) and (j), DAQ found that TGC supplied the information which was necessary to determine the HAP emission limits. This was confirmed by testimony from Adams, Handy, and even Dr. Fox.

884. With regard to whether DAQ lacked support for the 99.5+% non-mercury metallic HAP removal efficiency, the fact remains that this is the removal efficiency to which TGC will be held.

X. REVISIONS #1 and #2

885. Minor Revision #1 was issued on December 6, 2002. Although Petitioners filed a petition to challenge minor Revision #1 (Docket #1 in File No. DAQ-26048-037), they presented no claims as to minor Revision #1, but instead stated that the "(t)he revised permit does not appear to change the substance of any of the determinations complained of".

886. Revision #2 was issed on February 17, 2005. In Petitioners' petition challenging Revision #2 (Docket #332 in consolidated File No. DAQ-26003-037 and DAQ-26048-037), they agree with certain modifications which reflect changes they urged be made, but disagree with modifications they opposed.

887. I conclude that Petitioners failed to carry their burden of proof on Revisions #1 and #2, except for the changes which I recommend (in Counts 14 and 17) be addressed as a result of the remand of Title V/PSD Permit V-02-001.

XI. RECOMMENDATIONS

For the reasons set forth above, I respectfully recommend to the Secretary that she sign the attached Secretary's Order.

So RECOMMENDED this _____ day of _______________, 20___.

____

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EXCEPTION RIGHTS

Pursuant to KRS 224.10-440, any party may file exceptions to this Report and Recommendation within fourteen (14) days of receipt of this Report. The Secretary will then consider this Report, any Exceptions, and the recommended Order and decide this case.

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing HEARING OFFICER'S REPORT AND RECOMMENDED SECRETARY'S ORDER was, on this 9th day of August, 2005, emailed and hand delivered, to:

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COMMONWEALTH OF KENTUCKY
ENVIRONMENTAL AND PUBLIC PROTECTION CABINET
FILE NO. DAQ-26003-037 and DAQ-26048-037

SIERRA CLUB, VALLEY WATCH, INC.,
LESLIE BARRAS, HILARY LAMBERT, and
ROGER BRUCKER,

PETITIONERS,

VS.

ENVIRONMENTAL AND PROTECTION CABINET,
And
THOROUGHBRED GENERATING COMPANY, LLC

RESPONDENTS

****

SECRETARY'S FINAL ORDER

****

THIS MATTER is before the Secretary on the Report and Recommendation of the Hearing Officer, Hon. Janet C. Thompson. Having considered the Hearing Officer's Report and Recommendation and any exceptions thereto, and being otherwise sufficiently advised, **IT IS HEREBY ORDERED AND ADJUDGED** as follows:

1. The Hearing Officer's Report and Recommended Order filed in the record on August 9, 2005, is ADOPTED and incorporated by reference and made a part of this Final Order as if set forth verbatim in this Order.

2. Title V/PSD Air Quality Permit V-02-001, which was issued by the Cabinet's Division for Air Quality (DAQ) to Thoroughbred Generating Company (TGC) on October 11, 2002, is hereby REMANDED to DAQ, with the following directions:

Count 1 – Air Toxics, Risk

DAQ erred by relying on the Cumulative Assessment to satisfy the requirements of 401 KAR 63:020, Section 3.

DAQ SHALL evaluate the impact of TGS's potentially hazardous or toxic substances on animals.

Count 2 – Public Participation

Petitioners failed to carry their burden of proof on most of the arguments they advanced in Count 2, which relates to public participation, with the following exceptions**,** which DAQ shall correct on remand:

The SOB (Statement of Basis) should include an explanation why the permit's SCR (Selective Catalytic Reduction) control efficiency is less than that shown in a table in the SOB for SCRs. Also, the SOB should explain DAQ's reason for concluding that a dry ESP (Electrostatic Precipitator) is equivalent to a baghouse or what the "clear technical concerns" are that justify the use of ESP controls. In addition, the SOB should discuss DAQ's evaluation of TGS's potentially hazardous or toxic substances on animals.

Count 3 – Increment, NAAQS
Count 6 – Visibility – Mammoth Cave National Park
Count 7 – Coordination with Army Corps

Petitioners failed to establish a prima facie case as to Count 3 (Increment/NAAQS **–** National Ambient Air Quality Standards), Count 6 (Visibility – Mammoth Cave), and Count 7 (Coordination with Army Corps of Engineers). Hence, Petitioners' claims for relief on these Counts are DENIED.

Count 8 – Additional Impact Analysis, Soils, Vegetation

DAQ erred by determining that the Additional Impacts Analysis performed by TGC complies with 401 KAR 51:017 Section 14.

TGC SHALL perform and submit an Additional Impacts Analysis in accord with the conclusions in the Hearing Officer's Report.

Count 9 – Best Available Control Technology (BACT)

IGCC and CFB

DAQ erred as a matter of law by concluding that it lacked authority to require TGC to include IGCC (Integrated Gasification Combined Cycle) and CFB (Circulating Fluidized Bed) in its BACT (Best Available Control Technology) analysis.

DAQ SHALL require TGC to do a BACT analysis on both IGCC and CFB.

Coal Washing

DAQ's rejection of coal washing is arbitrary and capricious because TGC's cost-effectiveness analysis on which it is partly based is not supportable and understandable**.**

DAQ SHALL direct TGC to provide a cost-effectiveness determination for coal washing that includes consideration of both average and incremental cost effectiveness.

Clean Coals – Using a Blend of Lower Sulfur Coal as BACT

DAQ erred by failing to require TGC's SO_2 BACT analysis to include an evaluation of whether there are any economic, environmental or energy reasons why a lower BACT limit cannot be achieved by a blend of cleaner coals using the coal which TGS has available.

DAQ SHALL direct that TGC's SO_2 BACT analysis include this evaluation.

BACT for NO_x

DAQ's determination to issue the permit with a NO_x limit of 0.08 lb/MMbtu was contrary to fact and law.

DAQ SHALL make a new NO_x BACT determination.

BACT for PM or PM_{10}

This issue is MOOT as a result of Revision #2.

BACT for SO_2

DAQ's SO_2 BACT determination was erroneous because it was based on an inadequate analysis by TGC of the technical feasibility of meeting a limit of 99% reduction.

DAQ SHALL make a new SO_2 BACT determination.

BACT for Mercury and Beryllium

DAQ erroneously made a BACT determination based on TGC's elimination of carbon injection and fabric filters without the required technical feasibility analysis.

DAQ SHALL make a new BACT determination on mercury and beryllium.

Count 10 – Maximum Achievable Control Technology (MACT)

Petitioners failed to carry their burden of proof to establish that DAQ's mercury MACT and non-mercury MACT determinations are erroneous or arbitrary. Hence, Petitioners' claims for relief on this Count is DENIED.

Count 11 – Single Source

The issue of whether the mine and power plant are a single source is MOOT because of TGC's agreement that BACT will apply to both the emissions from the mine and the power plant.

DAQ SHALL require that TGC's agreement that BACT applies to both the emissions from the mine and the power plant be incorporated in the permit.

Count 14 - Enforceability

The HAPs, VOC and PM limits are not enforceable.

DAQ SHALL make a number of revisions to the permit, including the following:

For HAPs –

* The permit should indicate the primary method of determining compliance with HAPs limits.

* A HAPs coal test method, sampling procedure, and analysis procedure shall be identified in the permit.

* The test method should be capable of measuring HAPs at levels as low as the permit limits.

* More than four analyses of coal samples shall be required and shall be recorded more frequently than quarterly.

* All control system operating parameters shall be identified.

* The permit shall state how monitoring provisions are to be used and whether exceedance of the operating parameter amounts to an exceedance of the HAPs limits.

For Monitoring –

In light of TGC's acknowledgement that Revision #2 addresses all of the issues Petitioners raise with regard to compliance provisions which appear only in the SOB, DAQ SHALL require that the permit be so revised to the extent any of the above compliance provisions appear only in the SOB and not in the permit.

For VOCs -

More frequent stack testing (not just an initial stack test) shall be required to confirm the relationship between CO and VOCs and should be in the permit. The permit shall also specify the test method. These requirements shall also apply to the auxiliary boiler.

For PM -

1) The regulated pollutant shall be corrected for the auxiliary boiler, as Revision #2, item #7, did for the PC boilers.

2) The permit shall list test methods for PM/PM_{10} for the PC boilers and the auxiliary boiler. The test methods in the SOB need to be clarified so that the regulated pollutant is consistently identified.

3) Annual testing for the PC boilers is not adequate.

4) On remand, TGC shall be required to present a test plan to develop the relationship between opacity and PM; to revisit the relationship if the fuel changes, equipment is updated or operating modes change; the 5% opacity fudge factor should be eliminated unless the maximum PM emission rate is substantially lower than the upper end of the opacity range; TGS shall not be allowed to operate for extended periods of time at opacity levels that represent exceedance of the underlying PM limits; and periods of startup and shut down should not be exempted.

5) On remand, the location of the COMS shall be changed as a result of testimony showing that COMS now allow accurate opacity measurements in wet stacks.

6) PM control equipment operating parameters are inadequate for reasons cited by Petitioners. DAQ SHALL reassess the parameters, and the permit shall provide that an exceedance of the indicator range constitutes a PM violation.

For material handling units (units 4-9) –

Compliance with the monitoring and recordkeeping requirements of Title V Manual at pg. 6, Sec. 1b III and IV shall be required.

Count 17 – Errors and Omissions

The permit contains numerous errors and omissions.

DAQ is DIRECTED as follows:

Claims A, D, L, P, and W (second part) – DAQ should review.

Claim K – DAQ shall clarify the inconsistency between the permit and the SOB.

Claim Q – DAQ shall state in the SOB where it obtained Table 5.2.

Claim R – DAQ shall state that the 24-hr increment is 4.98 $\mu g/m^3$.

Claim S – DAQ shall correct typos in the SOB.

Count 18 – HAPs Emissions Estimates

Petitioners failed to carry their burden of proof on this Count.

Revisions #1 and #2

Petitioners failed to carry their burden of proof on any claims relating to Revisions #1 and #2. Thus, they are AFFIRMED, except for the changes which are necessary as a result of the remand of Title V/PSD Permit V-02-001.

So ORDERED this _____ day of ________________, 200_____.

ENVIRONMENTAL AND PUBLIC
PROTECTION CABINET

____
LAJUANA S. WILCHER
SECRETARY

APPEAL RIGHTS

In accordance with the provisions of KRS 224.10-470 and KRS 151.186, appeals may be taken from Final Orders of the Cabinet by filing in Circuit Court a Petition for Review. Such Petition must be filed within thirty (30) days from the entry of the Final Order, and a copy of the Petition must be served upon the Cabinet.

CERTIFICATE OF SERVICE

I hereby certify that a true and accurate copy of the foregoing SECRETARY'S ORDER was, on this _____ day of ____________, 20___, mailed first class mail, postage prepaid, to:

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