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Ms. Elizabeth O'Donnell
Executive Director
Kentucky Public Service Commission
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PUBLIC SERVICE COMMISSION

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September 7, 2006

RE: *In the Matter Of:* *The Application Of Kentucky Utilities Company For A Certificate Of Public Convenience And Necessity To Construct A Selective Catalytic Reduction System And Approval Of Its 2006 Compliance Plan For Recovery By Environmental Surcharge* - **Case No. 2006-00206**

Dear Ms. O'Donnell:

Enclosed please find an original and five (5) copies of Kentucky Utilities Company's ("KU") Response to the Second Data Request of Commission Staff dated August 21, 2006, in the above-referenced docket.

Also enclosed are an original and ten (10) copies of a Petition for Confidential Protection regarding information provided in response to Question No. 3(a).

Should you have any questions concerning the enclosed, please do not hesitate to contact me.

Sincerely,

Kent W Blake

Kent W. Blake

cc: Hon. Elizabeth E. Blackford
Hon. Michael L. Kurtz

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION



In the Matter of:

| | | |
|---|---|---|
| THE APPLICATION OF KENTUCKY UTILITIES COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY TO CONSTRUCT A SELECTIVE CATALYTIC REDUCTION SYSTEM AND APPROVAL OF ITS 2006 COMPLIANCE PLAN FOR RECOVERY BY ENVIRONMENTAL SURCHARGE | ) | CASE NO. 2006-00206 |

RESPONSE OF
KENTUCKY UTILITIES COMPANY
TO
SECOND DATA REQUEST OF
COMMISSION STAFF
DATED AUGUST 21, 2006

FILED: SEPTEMBER 7, 2006

**KENTUCKY UTILITIES COMPANY**

**CASE NO. 2006-00206**

**Response to Second Data Request of Commission Staff**
**Dated August 21, 2006**

**Question No. 1**

**Responding Witness: John P. Malloy**

Q-1. Refer to the response to the Commission Staff's First Data Request dated July 24, 2006 ("Staff's First Request"), Items 3(b) and 3(d).

a. For each of the emission types shown in the response to Item 3(b), explain why the expected total emissions for 2006 are higher than the actual total emissions for 2005.

b. Does KU anticipate that its mercury emissions will be impacted by the addition of scrubbers and selective catalytic reduction equipment at its generating units? Explain the response.

c. Refer to the response to Item 3(d).

(1) Have the Green River Units 1 and 2 and Pineville Unit 3 been retired? If yes, explain why there are entries on the various emission charts for these units.

(2) Describe the generating units identified as Green River Unit 5 and Tyrone Units 1, 2, 4, and 5.

(3) Explain why Tyrone Unit 3 was not included in the charts for sulfur dioxide ("$SO_2$") and mercury emissions.

A-1. a. Variance explanations for $SO_2$, $NO_x$ (ozone season and annual), and mercury emissions are discussed below.

**<u>Variance Explanation of $SO_2$ Emissions:</u>**
The majority of the difference in the projected 2006 annual $SO_2$ emissions and 2005 historical $SO_2$ emissions is attributed to lower than projected generation at E.W. Brown and the relatively low (when compared to the 2006 projections) $SO_2$ mass emission rate at the Ghent Station. Generation at Brown in 2005 was lower than that projected for 2006, mainly due to an unplanned outage event lasting 88 days. Meanwhile, Ghent 1 exhibited a higher FGD removal efficiency in 2005 than projected for 2006 while Ghent

2-4 burned the low sulfur, Powder River Basin (PRB) fuel in 2005 but is not expected to do so in 2006. The remainder of variances are attributable to differences in 2006 planning assumptions versus 2005 actuals with regards to maintenance, EFOR, heatrate and load.

**Variance Explanation of Ozone Season $NO_x$ Emissions:**
The majority of the difference in the ozone season $NO_x$ emissions is attributed to less generation in the 2005 ozone season than during the ozone season of 2006. For example, Brown 2 and Brown 3 had 5 and 3 weeks more of planned outages, respectfully, during the 2005 ozone season than the 2006 ozone season. The remainder of variances are attributable to differences in 2006 planning assumptions versus 2005 actuals with regards to maintenance, EFOR, heatrate and load.

**Variance Explanation of Annual $NO_x$ Emissions:**
The majority of the difference in the projected 2006 annual $NO_x$ emissions and 2005 historical $NO_x$ emissions is attributed to less generation at Brown.

**Variance Explanation of Annual Hg Emissions:**
For mercury, the approximately 640 tons difference in the estimated 2005 emissions and the projected 2006 values is due to the assumptions in the two different models used to produce the values. As stated in the response to Commission Staff's First Request Item 3(a), the estimated 2005 emissions are produced using the EPRI Lark-Tripp model for purposes of reporting information in the Toxic Release Inventory. The projected 2006 values were produced from the PROSYM production costing model used for planning purposes. Mercury content of the fuel is the primary assumption in both models that creates the largest variance. In the Lark-Tripp model, mercury content is allowed to be varied per station. The mercury content data used comes from data collected at each station during a 1999 Information Collection Request issued by the United States Environmental Protection Agency ("USEPA") regarding coal mercury contents. In the PROSYM model, an average mercury content is used for all stations to account for variations in coal quality in future year planning. The average value is based on data used in the USEPA's Integrated Planning Model. The following table displays the mercury contents utilized in each model.

**Coal Mercury Contents Used in Models (ppb)**

| Model | E.W. Brown | Ghent | Green River | Tyrone |
|---|---|---|---|---|
| EPRI Lark-Tripp | 92 | 60 | 80 | 52 |
| Planning Model | 113 | 113 | 113 | 113 |

b. Yes, the following table quantifies the amount of mercury reduction assumed to occur on each unit and is dependant on the configuration of the equipment in service at the station. Note that the addition of a selective catalytic reduction system ("SCR") to a unit with only a hot or cold side electrostatic precipitator ("ESP") is not assumed to reduce mercury emissions. However, the addition of flue gas desulphurization equipment ("FGD") to a unit with either a hot or cold side ESP does increase the assumed mercury removal percentage. The addition of an SCR to a unit with an FGD achieves the highest assumed mercury removal percentage.

## Assumed Mercury Removal Percentages

| | Fuel Type | |
|---|---|---|
| **Unit Configuration** | Bituminous | Subbituminous |
| Cold Side ESP | 36% | n/a |
| Cold Side ESP + SCR | 36% | n/a |
| Cold Side ESP + SCR + WFGD | 90% | 66% |
| Cold Side ESP + WFGD | 66% | n/a |
| Hot Side ESP | 10% | n/a |
| Hot Side ESP + SCR | 10% | n/a |
| Hot Side ESP + SCR + WFGD | 90% | n/a |
| Hot Side ESP + WFGD | 42% | n/a |

Notes:
**Hot Side ESP--> Hot Side Electrostatic Precipitator**
**Cold Side ESP--> Cold Side Electrostatic Precipitator**
**SCR--> Selective Catalytic Reduction**
**WFGD-->Wet Flue Gas Desulphurization**
**n/a-> No units on the Companies' system in this category**

c. (1) Green River Units 1 and 2 and Pineville Unit 3 have been retired. The tables shown in the response to Commission Staff's First Request Item 3(d) display the projected number of allowances and not the projected emissions. As stated in the response to Commission Staff's First Request Item 3(d), the State of Kentucky is in the process of incorporating the CAIR regulation. Therefore, the final allocation methodologies for 2009 and subsequent years are unknown at this time. The following paragraphs describe the methods and assumptions used to produce the projected allocations provided in the response to Commission Staff's First Request Item 3(c) and Item 3(d).

Under the Acid Rain Program, Green River Unit 1 and 2 and Pineville Unit 3 obtained $SO_2$ allowances. In that program, retired units continue to receive $SO_2$ allowances. The Kentucky Division for Air Quality ("KDAQ") has stated that the Acid Rain Program $SO_2$ allowances will be used in the CAIR $SO_2$ program. For the provided projections, it was assumed that Ozone-season $NO_x$ allocations under CAIR would be handled similar to Kentucky's existing $NO_x$ Budget Program, in which retired units do not receive allocations. Under the existing program, allocations are based on heat input during recent years preceding the allocation period; for example, allocations for 2004-2006 were based on heat input during 1998-2000, allocations for 2007-2009 were based on heat input during 2001-2003, and so on. Green River Units 1 and 2 and Pineville Unit 3 obtained allowances under the existing program (as seen in year 2006 of the Ozone Season $NO_x$ Allowance chart) because they had not been retired at the time those allocations were given.

For the Annual $NO_x$ allocations under CAIR, it was assumed that the years for baseline heat input would not change for each allocation period. This approach was contained in the USEPA's CAIR Model Rule and is similar to the Acid Rain $SO_2$ allowance program. The Company's projections were based on the most recent years for which state-wide heat input values were available, which were 2002-2004. Since Green River Units 1 and 2 had heat input in 2002 and 2003, they were projected to receive Annual $NO_x$ allowances. Pineville Unit 3 did not have heat input during 2002-2004 and was therefore projected not to receive an allocation.

(2) The Green River and Tyrone Generating Stations have electric generators that are turned by steam from multiple boilers. USEPA defines "units" as the physical source of emissions. Allocations and emissions are based on these "units", rather than generation units. Green River 5 refers to the 5th boiler at the Green River facility, while Tyrone 1-5 refers to the 5 boilers that are at the Tyrone facility. Green River Units 1 – 2 were able to be powered by steam from boilers 1, 2 or 3. The 4th boiler at Green River serves only Green River Unit 3 and the 5th boiler is dedicated to Green River Unit 4. Similarly, at Tyrone, boilers 1-4 were originally designed to provide steam to Tyrone generator 1 or 2 or both simultaneously, while boiler 5 provides steam to the 3rd generator. The table below lists the boilers with the respective electric generator served.

| Location | Boiler | Generator |
|---|---|---|
| Green River | 1 | 1 and/or 2 |
| Green River | 2 | |
| Green River | 3 | |
| Green River | 4 | 3 |
| Green River | 5 | 4 |
| Tyrone | 1 | 1 and/or 2 |
| Tyrone | 2 | |
| Tyrone | 3 | |
| Tyrone | 4 | |
| Tyrone | 5 | 3 |

(3) Tyrone generator 3 is associated with Tyrone boiler number 5 which is shown in the tables identifying the projected number of annual $SO_2$ and mercury allowances expected to be allocated to the unit.

**KENTUCKY UTILITIES COMPANY**

**CASE NO. 2006-00206**

**Response to Second Data Request of Commission Staff**
**Dated August 21, 2006**

**Question No. 2**

**Responding Witness: Kent W. Blake / Sharon L. Dodson / Counsel**

Q-2. Refer to the response to the Staff's First Request, Item 4.

a. Under the provisions of KRS 278.183(1), a utility shall be entitled to the current recovery of its costs of complying with the Federal Clean Air Act as amended and those federal, state, or local environmental requirements which apply to coal combustion wastes and by-products resulting from the production of energy by the burning of coal. Other than the "general duty" provisions of KRS 224 cited in the May 19, 2006 letter from the Kentucky Division of Air Quality, what specific requirements have been issued by federal, state, or local agencies concerning the emission of sulfur trioxide ("$SO_3$")?

b. Absent specific emission limits or requirements, explain in detail why KU believes it is permitted to seek current cost recovery under the provisions of KRS 278.183(1) of its $SO_3$ mitigation costs.

A-2. The language of KRS 278.183 states: "a utility shall be entitled to the current recovery of its costs of complying with the Federal Clean Air Act as amended and those federal, state, or local environmental requirements which apply to coal combustion wastes and by-products resulting from the production of energy by the burning of coal." The environmental requirements in the Federal Clean Air Act as amended ("CAAA") and in other federal, state and local laws or regulations include, but are not limited to, environmental requirements with specific emission limits. Likewise, the statute is not limited to recovery of the costs of facilities used to comply with "specific emission limits." Rather, the statute simply provides for recovery of costs of complying with all types of environmental requirements.

Federal, state, or local environmental requirements are not limited to only specific emission limitations (i.e. "command and control" approach), but include other types of environmental requirements such as the "cap-and-trade" approach used under the $NO_x$ SIP call environmental requirements under the CAAA and the general obligation to control polluting emissions. $SO_3$ is a waste resulting from the production of energy by KU's burning of coal, under KRS 278.183.

Appropriate $SO_3$ mitigation is an environmental requirement under state and federal law.

a. The Kentucky Division for Air Quality ("KDAQ") has directed that appropriate $SO_3$ mitigation is required under the "general duty" provisions of the state air program. The United States Environmental Protection Agency ("USEPA") has clarified that $SO_3$ mitigation is also mandated by federal regulations under the CAAA. USEPA has acknowledged that high sulfur coal-burning plants that utilize SCR and FGD controls to meet the $SO_2$ and $NO_x$ limits under the CAIR will experience increased $SO_3$ which converts to sulfuric acid ("$H_2SO_4$") under certain circumstances. In assessing the compliance measures mandated by the CAIR, USEPA has clarified that such plants are required to implement $SO_3$ mitigation measures. In the supplemental notice of reconsideration for the CAIR rule, USEPA stated that "we assumed that every unit that is projected to install SCR and/or wet FGD will incur increased costs for $SO_3/H_2SO_4$ mitigation." *Rule To Reduce Interstate Transport of Fine Particulate Matter and Ozone (Clean Air Interstate Rule): Supplemental Notice of Reconsideration*, 70 Fed. Reg. 77101, 77106 [December 29, 2005].[1] Please also see the response to Staff Second Data Request Question No. 3a, with respect to potential opacity exceedances due to failure to mitigate $SO_3$ emissions.

b. The clear and unambiguous language of the surcharge statute requires the recovery of costs of complying with environmental requirements. While there are no specific $SO_3$ emission limits under the CAAA, the agencies charged with administering the Act advise that there are requirements under the Act that mandate the mitigation of $SO_3$ emissions and KU is required to comply with those requirements.

   The basic environmental regulatory concern regarding $SO_3$ emissions centers around the fact that high sulfur coal burning plants that utilize both SCRs and FGDs emit increased $SO_3$ which converts to sulfuric acid mist ($H_2SO_4$) and may discolor a plant's plume or even descend to ground level under certain circumstances. Discoloration of the plume by sulfuric acid mist can result in violation of the applicable particulate (opacity) standard specified in 401 KAR 61:015. Plume "touchdowns" can potentially pose a hazard to human health or the environment. Clearly, as indicated in the response to Question 2(a),

[1] Citing New York et al. v. EPA, 413 F.3d 3, (D.C. Cir. 2005), which invalidated the Pollution Control Project Exemption formerly exempting $SO_3/H_2SO_4$ emission increases associated with SCR/wet FGD installations, USEPA noted that "[a]s a result of that decision, either CAIR sources will need to mitigate [$SO_3/H_2SO_4$] emissions .... or they may choose to apply for NSR permits." 70 Fed. Reg. at 77109. Please note that obtaining an NSR permit would involve implementation of pollution control measures far more expensive than $SO_3$ abatement for which cost recovery is sought here.

both KDAQ and USEPA have interpreted their authority under the CAAA as sufficient to impose the environmental requirement of $SO_3$ mitigation.

Moreover, state and federal regulatory agencies have undertaken enforcement action under the CAAA and its state equivalents to compel $SO_3$ mitigation. In State of Illinois v. PSI Energy,[2] the state obtained a temporary injunction that required $SO_3$ mitigation measures, including shutdown of a generating unit in certain circumstances.

Based on the interpretations of the state and federal agencies charged with enforcing the CAAA as well as on judicial precedents, the Company believes that failure to undertake appropriate $SO_3$ mitigation measures would subject it to the significant risk of enforcement under the CAAA that could have significant financial implications.

Finally, in the past, the Commission has interpreted and applied KRS 278.183 to allow recovery of environmental costs incurred in complying with environmental requirements other than specific emission limits. For example, the $NO_x$ SIP Call, CAIR, and CAMR regulations under the CAAA impose "cap and trade" programs without any plant-specific emission limits: and the Commission has allowed recovery of such compliance costs in prior ECR cases. In addition, in Case No. 2004-00421, the Commission allowed recovery of the costs of the Mill Creek wet stack conversion project aimed at controlling "reactive particle" emissions from the plant, even though there was no specific emissions limit for reactive particles. The Louisville Air Pollution Control District required the measures pursuant to Regulation 1.09 (Prohibition of Air Pollution) and 1.12 (Control of Nuisances), general environmental protection requirements similar to the general duty provisions of KRS Chapter 224 cited by the Kentucky Division for Air Quality as authority for control of $SO_3$. Thus, there is established precedent for the ECR recovery of costs incurred to comply with environmental requirements other than specific emission limits.

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[2] Case No. 2004 CH 20, Circuit Court for the Second Judicial Circuit, Wabash County, Illinois 2004, rev'd on other grounds sub nom. People ex rel. Madigan v. PSI Energy, 1042, 847 N.E.2nd 514 (Ill. App. 2006) (forbidding Illinois Attorney General to use Illinois law to enjoin emissions from source located in Indiana).

**KENTUCKY UTILITIES COMPANY**

**CASE NO. 2006-00206**

**Response to Second Data Request of Commission Staff**
**Dated August 21, 2006**

**Question No. 3**

**Responding Witness: Sharon L. Dodson / John P. Malloy**

Q-3. Refer to the response to the Staff's First Request, Item 4(d). In this response, KU states,

> The findings in the Sargent and Lundy $SO_3$ Mitigation Study, Exhibit JPM-4, established that a visible stack plume (discounting the portion consisting of water vapor) dissipates rapidly when stack gases are controlled to an $SO_3$ concentration level of approximately five (5) parts per million ("ppm"). Hence, based on this study, the Company has identified a value of 5 ppm $SO_3$ which can be used as a practical guideline for its compliance efforts.

Exhibit JPM-4 of the Direct Testimony of John P. Malloy contains the following statements:

> The target $SO_3$ concentration at the stack exit was set at 5 ppm, which is the recommended level for low stack opacity (no visible plume). [Page 4 of 42]
>
> * * * * *
>
> For the purposes of this study, the $SO_3/H_2SO_4$ in the flue gas will need to be reduced to 5 ppm or less to mitigate the "blue" plume phenomenon. Although limited data exists on the relationship between $SO_3/H_2SO_4$ concentration and plume visibility, a level of 5 ppm was selected, as it would eliminate the visible plume under most atmospheric conditions. [Page 8 of 42]

a. Would KU agree that, based upon the statements from Exhibit JPM-4, it appears that the study set the $SO_3$ emission limit at 5 ppm in order to evaluate mitigation options, rather than establishing what the reasonable $SO_3$ emission level should be? Explain the response.

b. Page 8 of 42 in Exhibit JPM-4 shows a chart relating flue gas $SO_3$ concentration with estimated plume opacity for different stack diameters. What are the diameters of the stacks at Ghent Units 1, 3, and 4?

c. Provide copies of the Environmental Protection Agency's Method 9 protocols referenced in the response to Item 4(d).

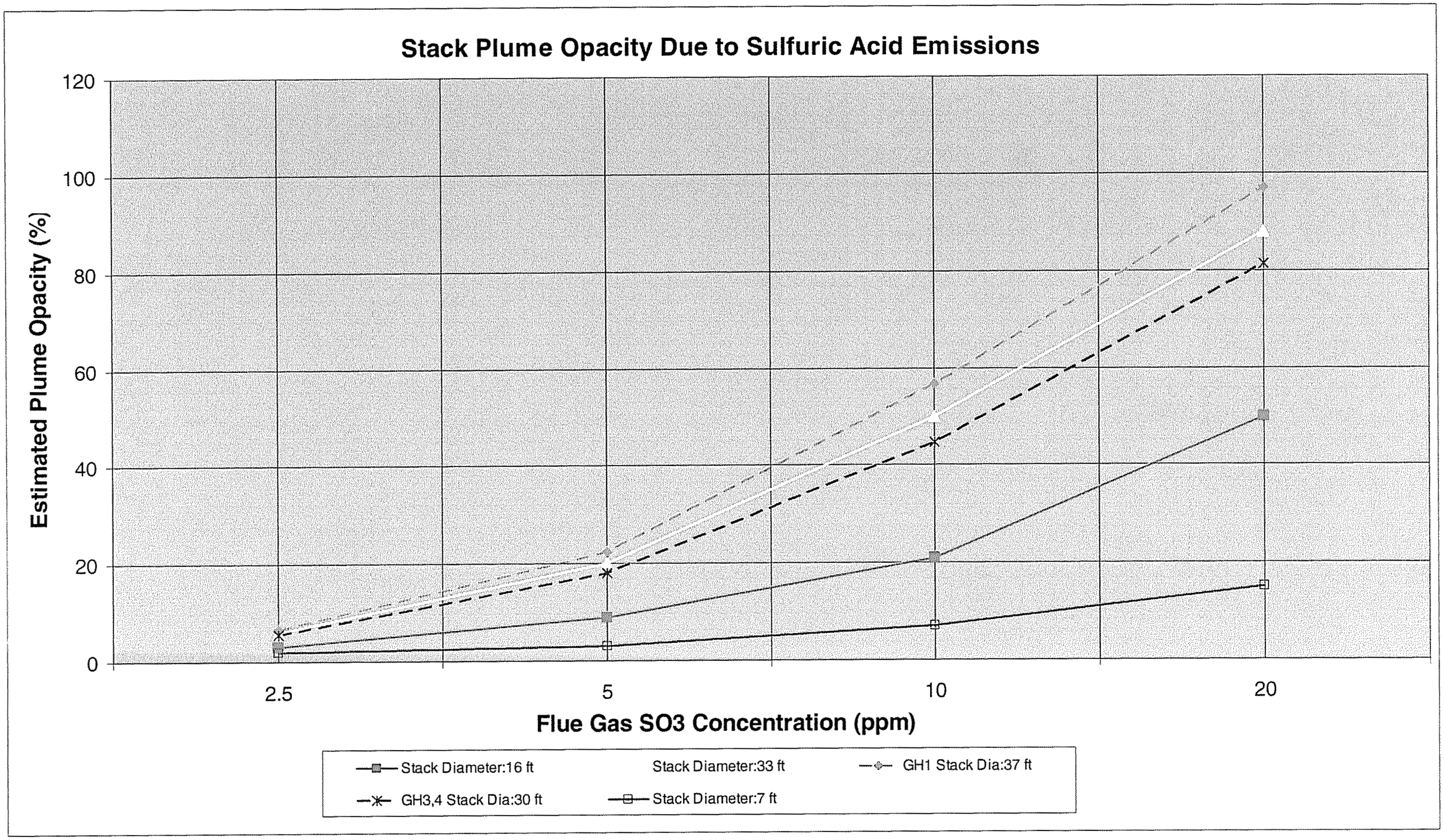
A-3. a. The Electric Power Research Institute ("EPRI") has issued an $SO_3$ mitigation guide based on their research and industry experience with $SO_3$ emissions and mitigation technologies. The report and a portion of the response to this question are being filed with the Commission under seal pursuant to a Petition for Confidential Protection [redacted] As included on Page 8 of 42 in Exhibit JPM-4, EPRI provides a chart relating flue gas $SO_3$ concentration with estimated plume opacity for different stack diameters (see response to item 3b below). By interpolation, the Ghent stack diameter curves can be plotted on the graph (see attached Graph 1 which shows the current stack diameters for the Ghent units). As indicated by this graph, a target of 5 ppm $SO_3$ concentration in the flue gas should allow the Company to maintain the plume opacity below 40% for Ghent 1, and 20% for Ghent 3 and 4 (the current regulatory limit on opacity for these units). Therefore, 5 ppm $SO_3$ concentration in the flue gas was selected as the screening level for $SO_3$ emission mitigation alternatives in order to control plume opacity and maintain compliance with current opacity regulations at Ghent Station.

Post-FGD construction, the stack diameter for all three Ghent units will change. Per the attached Graph II, the Ghent 1 plume opacity may be maintainable at a slightly higher $SO_3$ concentration (~8 ppm), reducing the required sorbent injection flow for this unit. Ghent 3 may require an increase in sorbent injection to maintain the plume opacity below 20%, due to the increase in stack diameter. Ghent 4 will remain substantially the same, per Graph II. However, final operational control parameters will be established through testing and calibration for each unit and application of USEPA Method 9 testing.

b. At Ghent Unit 1, the current stack diameter is 37 feet. The FGD construction project will move Ghent Unit 1's flue gas to a stack with a diameter of 26.5 feet. The Ghent Unit 3 current stack diameter is 30 feet. The FGD construction project will combine Ghent Unit 3's flue gas with Ghent Unit 2 in a stack with a diameter of 37 feet. The Ghent Unit 4 current stack diameter is 30 feet. The FGD construction project will move Ghent Unit 4's flue gas to a stack with a diameter of 26.5 feet.

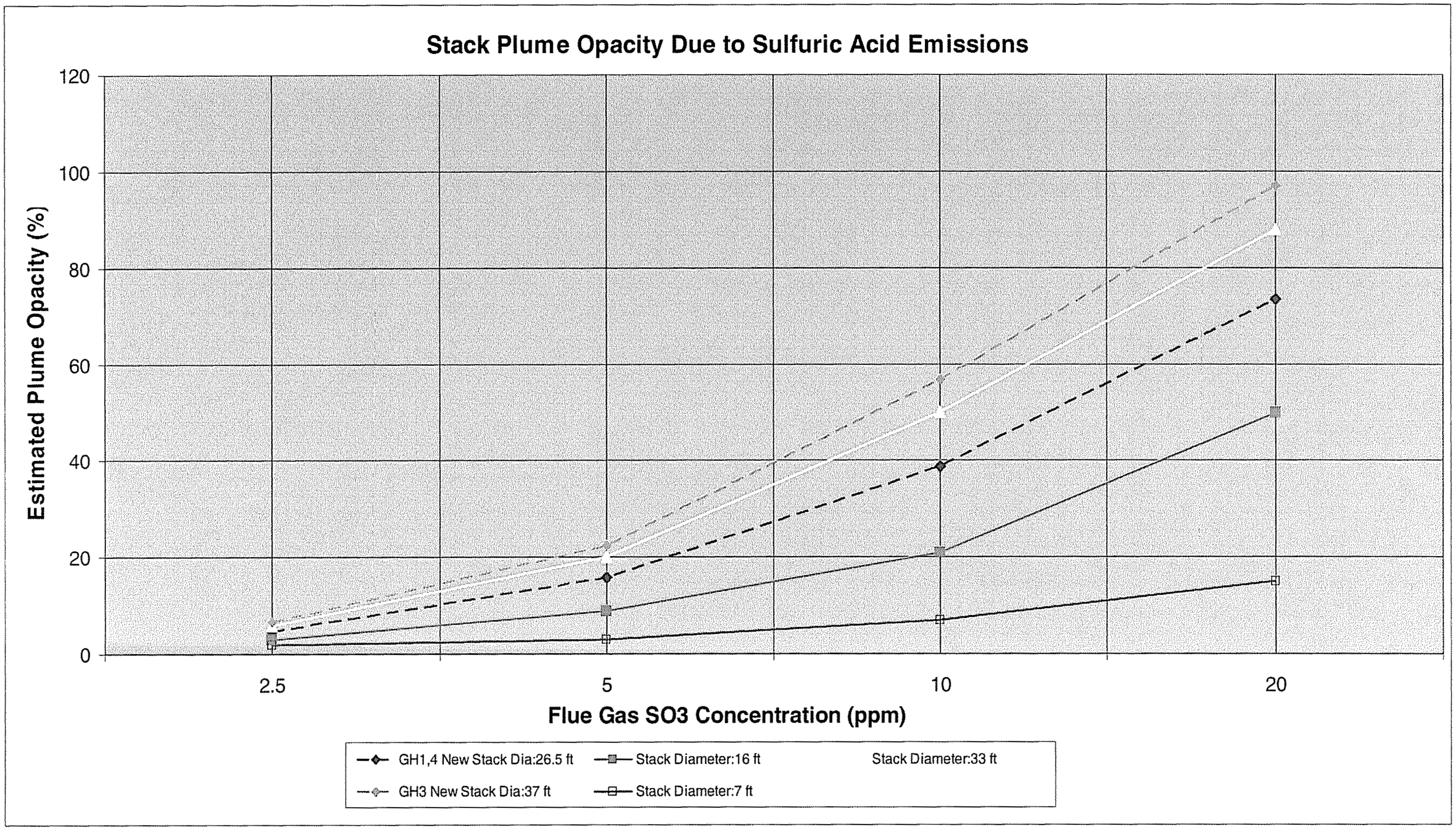
c. The procedures for performing a USEPA Method 9 test (as found at www.epa.gov/ttn/emc/promgate.html) are attached to this response. USEPA Method 9 is the compliance method for determination of visible emissions associated with a stack plume. Persons conducting Method 9 testing are required to attend training and maintain a certification of their ability to accurately perform the method. Method 9 is used by the USEPA to determine compliance with opacity emission standards.

## Chart I



Stack Plume Opacity Due to Sulfuric Acid Emissions
Estimated Plume Opacity (%)
120
100
80
60
40
20
0
2.5
5
10
20
Flue Gas SO3 Concentration (ppm)
Stack Diameter:16 ft
Stack Diameter:33 ft
GH1 Stack Dia:37 ft
GH3,4 Stack Dia:30 ft
Stack Diameter:7 ft

# Chart II



Stack Plume Opacity Due to Sulfuric Acid Emissions
Estimated Plume Opacity (%)
120
100
80
60
40
20
0
2.5
5
10
20
Flue Gas SO3 Concentration (ppm)
GH1,4 New Stack Dia:26.5 ft
Stack Diameter:16 ft
Stack Diameter:33 ft
GH3 New Stack Dia:37 ft
Stack Diameter:7 ft

**EMISSION MEASUREMENT TECHNICAL INFORMATION CENTER**
**NSPS TEST METHOD**

Prepared by **Emission Measurement Branch** | **EMTIC TM-009**
Technical Support Division, OAQPS, EPA | October 25, 1990

**Method 9 - Visual Determination of the Opacity of Emissions from Stationary Sources**

**INTRODUCTION**

**(a)** Many stationary sources discharge visible emissions into the atmosphere; these emissions are usually in the shape of a plume. This method involves the determination of plume opacity by qualified observers. The methods includes procedures for the training and certification of observers and procedures to be used in the field for determination of plume opacity.

**(b)** The appearance of a plume as viewed by an observer depends upon a number of variables, some of which may be controllable in the field. Variables which can be controlled to an extent to which they no longer exert a significant influence upon plume appearance include: angle of the observer with respect to the plume; angle of the observer with respect to the sun; point of observation of attached and detached steam plume; and angle of the observer with respect to a plume emitted from a rectangular stack with a large length to width ratio. The method includes specific criteria applicable to these variables.

**(c)** Other variables which may not be controllable in the field are luminescence and color contrast between the plume and the background against which the plume is viewed. These variables exert an influence upon the appearance of a plume as viewed by an observer and can affect the ability of the observer to assign accurately opacity values to the observed plume. Studies of the theory of plume opacity and field studies have demonstrated that a plume is most visible and presents the greatest apparent opacity when viewed against a contrasting background. Accordingly, the opacity of a plume viewed under conditions where a contrasting background is present can be assigned with the greatest degree of accuracy. However, the potential for a positive error is also the greatest when a plume is viewed under such contrasting conditions. Under conditions presenting a less contrasting background, the apparent opacity of a plume is less and approaches zero as the color and luminescence contrast decrease toward zero. As a result, significant negative bias and negative errors can be made when a plume is viewed under less contrasting conditions. A negative bias decreases rather than increases the possibility that a plant operator will be incorrectly cited for a violation of opacity standards as a result of observer error.

**(d)** Studies have been undertaken to determine the magnitude of positive errors made by qualified observers while reading plumes under contrasting conditions and using the procedures set forth in this method. The results of these studies (field trials) which involve a total of 769 sets of 25 readings each are as follows:

(1) For black plumes (133 sets at a smoke generator), 100 percent of the sets were read with a positive error of less than 7.5 percent opacity; 99 percent were read with a positive error of less than 5 percent opacity. (Note: For a set, positive error = average opacity determined by observers' 25 observations -average opacity determined from transmissometer's 25 recordings.)

(2) For white plumes (170 sets at a smoke generator, 168 sets at a coal-fired power plant, 298 sets at a sulfuric acid plant), 99 percent of the sets were read with a positive error of less than 7.5 percent opacity; 95 percent were read with a positive error of less than 5 percent opacity.

**(e)** The positive observational error associated with an average of twenty-five readings is therefore established. The accuracy of the method must be taken into account when determining possible violations of applicable opacity standards.

## 1. PRINCIPLE AND APPLICABILITY

**1.1 Principle.** The opacity of emissions from stationary sources is determined visually by a qualified observer.

**1.2 Applicability.** This method is applicable for the determination of the opacity of emissions from stationary sources pursuant to § 60.11(b) and for visually determining opacity of emissions.

## 2. PROCEDURES

The observer qualified in accordance with Section 3 of this method shall use the following procedures for visually determining the opacity of emissions.

**2.1 Position.** The qualified observer shall stand at a distance sufficient to provide a clear view of the emissions with the sun oriented in the 140° sector to his back. Consistent with maintaining the above requirement, the observer shall, as much as possible, make his observations from a position such that his line of vision is approximately perpendicular to the plume direction and, when observing opacity of emissions from rectangular outlets (e.g., roof monitors, open baghouses, noncircular stacks), approximately perpendicular to the longer axis of the outlet. The observer's line of sight should not include more than one plume at a time when multiple stacks are involved, and in any case the observer should make his observations with his line of sight perpendicular to the longer axis of such a set of multiple stacks (e.g., stub stacks on baghouses).

**2.2 Field Records.** The observer shall record the name of the plant, emission location, facility type, observer's name and affiliation, and the date on a field data sheet (Figure 9-1). The time, estimated distance to the emission location, approximate wind direction, estimated wind speed, description of the sky condition (presence and color of clouds), and plume background are recorded on a field data sheet at the time opacity readings are initiated and completed.

**Figure 9-1. Record of visual determination of opacity.**

Company__________
Location__________
Test No.__________
Date__________
Type Facility__________
Control Device__________
Hours of Observation__________
Observer__________
Observer Certification Date________ Observer Affiliation______
Point of Emissions__________ Height of Discharge__________

| | | | | |
|---|---|---|---|---|
| CLOCK TIME | Initial | | | Final |
| OBSERVER LOCATION | | | | |
| Distance to discharge | | | | |
| Direction from | | | | |
| Height of observation | | | | |
| BACKGROUND DESCRIPTION | | | | |
| WEATHER CONDITIONS | | | | |
| Wind Direction | | | | |
| Wind Speed | | | | |
| Ambient Temperature | | | | |
| SKY CONDITIONS (clear, overcast, % clouds, etc.) | | | | |
| PLUME DESCRIPTION | | | | |
| Color | | | | |
| Distance Visible | | | | |
| OTHER INFORMATION | | | | |

SUMMARY OF AVERAGE OPACITY

| Set Number | Time | Opacity | |
|---|---|---|---|
| | Start - End | Sum | Average |
| | | | |
| | | | |
| | | | |
| | | | |

Readings ranged from ___ to ___ % opacity.

The source was/was not in compliance with ___ at the time evaluation was made.

**Figure 9-2. Observation record.**

Page ___ of ___

Company ________________________________ Observer ________________________________

Location ________________________________ Type facility ________________________________

Test Number ________________________________ Point of emissions ________________________________

Comments

| Hr | Min | Seconds 0 | 15 | 30 | 45 | Steam plume (check if applicable) Attached | Detached | Comments |
|---|---|---|---|---|---|---|---|---|
| | 0 | | | | | | | |
| | 1 | | | | | | | |
| | 2 | | | | | | | |
| | 3 | | | | | | | |
| | 4 | | | | | | | |
| | 5 | | | | | | | |
| | 6 | | | | | | | |
| | 7 | | | | | | | |
| | 8 | | | | | | | |
| | 9 | | | | | | | |
| | 10 | | | | | | | |
| | 11 | | | | | | | |
| | 12 | | | | | | | |
| | 13 | | | | | | | |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 14 | | | | | | | |
| | 15 | | | | | | | |
| | 16 | | | | | | | |
| | 17 | | | | | | | |
| | 18 | | | | | | | |
| | 19 | | | | | | | |
| | 20 | | | | | | | |
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**Figure 9-2. Observation record (continued).**

Page ___ of ___

Company ______________ Observer ______________

Location ______________ Type facility ______________

Test Number ______________ Point of emissions ______________

| | | Seconds | | | | Steam plume (check if applicable) | | Comments |
|---|---|---|---|---|---|---|---|---|
| Hr | Min | 0 | 15 | 30 | 45 | Attached | Detached | |
| | 30 | | | | | | | |
| | 31 | | | | | | | |
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**2.3 Observations.** Opacity observations shall be made at the point of greatest opacity in that portion of the plume where condensed water vapor is not present. The observer shall not look continuously at the plume but instead shall observe the plume momentarily at 15-second intervals.

**2.3.1 Attached Steam Plumes.** When condensed water vapor is present within the plume as it emerges from the emission outlet, opacity observations shall be made beyond the point in the plume at which condensed water vapor is no longer visible. The observer shall record the approximate distance from the emission outlet to the point in the plume at which the observations are made.

**2.3.2 Detached Steam Plume.** When water vapor in the plume condenses and becomes visible at a distinct distance from the emission outlet, the opacity of emissions should be evaluated at the emission outlet prior to the condensation of water vapor and the formation of the steam plume.

**2.4 Recording Observations.** Opacity observations shall be recorded to the nearest 5 percent at 15-second intervals on an observational record sheet. (See Figure 9-2 for an example.) A minimum of 24 observations shall be recorded. Each momentary observation recorded shall be deemed to represent the average opacity of emissions for a 15-second period.

**2.5 Data Reduction.** Opacity shall be determined as an average of 24 consecutive observations recorded at 15-second intervals. Divide the observations recorded on the record sheet into sets of 24 consecutive observations. A set is composed of any 24 consecutive observations. Sets need not be consecutive in time and in no case shall two sets overlap. For each set of 24 observations, calculate the average by summing the opacity of the 24 observations and dividing this sum by 24. If an applicable standard specifies an averaging time requiring more than 24 observations, calculate the average for all observations made during the specified time period. Record the average opacity on a record sheet. (See Figure 9-1 for an example.)

**3. QUALIFICATION AND TESTING**

**3.1 Certification Requirements.** To receive certification as a qualified observer, a candidate must be tested and demonstrate the ability to assign opacity readings in 5 percent increments to 25 different black plumes and 25 different white plumes, with an error not to exceed 15 percent opacity on any one reading and average error not to exceed 7.5 percent opacity in each category. Candidates shall be tested according to the procedures described in Section 3.2. Smoke generators used pursuant to Section 3.2 shall be equipped with a smoke meter which meets the requirements of Section 3.3. The certification shall be valid for a period of 6 months, at which time the qualification procedure must be repeated by any observer in order to retain certification.

**3.2 Certification Procedure.** The certification test consists of showing the candidate a complete run of 50 plumes--25 black plumes and 25 white plumes-generated by a smoke generator. Plumes within each set of 25 black and 25 white runs shall be presented in random order. The candidate assigns an opacity value to each plume and records his observation on a suitable form. At the completion of each run of 50 readings, the score of the candidate is determined. If a candidate fails to qualify, the complete run of 50 readings must be repeated in any retest. The smoke test may be administered as part of a smoke school or training program and may be preceded by training or familiarization runs of the smoke generator during which candidates are shown black and white plumes of known opacity.

**3.3 Smoke Generator Specifications.** Any smoke generator used for the purposes of Section 3.2 shall be equipped with a smoke meter installed to measure opacity across the diameter of the smoke generator stack. The smoke meter output shall display in-stack opacity based upon a pathlength equal to the stack exit diameter, on a full 0 to 100 percent chart recorder scale. The smoke meter optical design and performance shall meet the specifications shown in Table 9—1. The smoke meter shall be calibrated as prescribed in Section 3.3.1 prior to the conduct of each smoke reading test. At the completion of each test, the zero and span drift shall be checked and if the drift exceeds ±1 percent opacity, the condition shall be corrected prior to conducting any subsequent test runs. The smoke meter shall be demonstrated, at the time of installation, to meet the specifications listed in Table 9-1. This demonstration shall be repeated following any subsequent repair or replacement of the photocell or associated electronic circuitry including the chart recorder or output meter, or every 6 months, whichever occurs first.

TABLE 9-1 - SMOKE METER DESIGN AND PERFORMANCE SPECIFICATIONS

| Parameter | Specification |
|---|---|
| a. Light Source | Incandescent lamp operated at nominal rated voltage |
| b. Spectral reponse of photocell | Photopic (daylight spectral response of the human eye - Citation 3) |
| c. Angle of view | 15° maximum total angle |
| d. Angle of projection | 15° maximum total angle |
| e. Calibration error | ±3% opacity, maximum |
| f. Zero and span drift | ±1% opacity, 30 minutes |
| g. Response time | 5 seconds |

**3.3.1 Calibration.** The smoke meter is calibrated after allowing a minimum of 30 minutes warmup by alternately producing simulated opacity of 0 percent and 100 percent. When stable response at 0 percent or 100 percent is noted, the smoke meter is adjusted to produce an output of 0 percent or 100 percent, as appropriate. This calibration shall be repeated until stable 0 percent and 100 percent opacity values may be produced by alternately switching the power to the light source on and off while the smoke generator is not producing smoke.

**3.3.2 Smoke Meter Evaluation.** The smoke meter design and performance are to be evaluated as follows:

**3.3.2.1 Light Source.** Verify from manufacturer's data and from voltage measurements made at the lamp, as installed, that the lamp is operated within ±5 percent of the nominal rated voltage.

**3.3.2.2 Spectral Response of Photocell.** Verify from manufacturer's data that the photocell has a photopic response; i.e., the spectral sensitivity of the cell shall closely approximate the standard spectral-luminosity in (b) of Table 9–1.

**3.3.2.3 Angle of View.** Check construction geometry to ensure that the total angle of view of the smoke plume, as seen by the photocell, does not exceed 15°. The total angle of view may be calculated from: $\Theta = 2 \tan^{-1} (d/2L)$, where $\Theta$ = total angle of view; d = the sum of the photocell diameter + the diameter of the limiting aperture; and L = the distance from the photocell to the limiting aperture. The limiting aperture is the point in the path between the photocell and the smoke plume where the angle of view is most restricted. In smoke generator smoke meters this is normally an orifice plate.

**3.3.2.4 Angle of Projection.** Check construction geometry to ensure that the total angle of projection of the lamp on the smoke plume does not exceed 15°. The total angle of projection may be calculated from: $\Theta = 2 \tan^{-1} (d/2L)$, where $\Theta$ = total angle of projection; d = the sum of the length of the lamp filament + the diameter of the limiting aperture; and L = the distance from the lamp to the limiting aperture.

**3.3.2.5 Calibration Error.** Using neutral-density filters of known opacity, check the error between the actual response and the theoretical linear response of the smoke meter. This check is accomplished by first calibrating the smoke meter according to Section 3.3.1 and then inserting a series of three neutral-density filters of nominal opacity of 20, 50, and 75 percent in the smoke meter pathlength. Filters calibrated within 2 percent shall be used. Care should be taken when inserting the filters to prevent stray light from affecting the meter. Make a total of five nonconsecutive readings for each filter. The maximum error on any one reading shall be 3 percent opacity.

**3.3.2.6 Zero and Span Drift.** Determine the zero and span drift by calibrating and operating the smoke generator in a normal manner over a 1-hour period. The drift is measured by checking the zero and span at the end of this period.

**3.3.2.7 Response Time.** Determine the response time by producing the series of five simulated 0 percent and 100 percent opacity values and observing the time required to reach stable response. Opacity values of 0 percent and 100 percent may be simulated by alternately switching the power to the light source off and on while the smoke generator is not operating.

## 4. BIBLIOGRAPHY

1. Air Pollution Control District Rules and Regulations, Los Angeles County Air Pollution Control District, Regulation IV, Prohibitions, Rule 50.

2. Weisburd, Melvin I., Field Operations and Enforcement Manual for Air, U.S. Environmental Protection Agency, Research Triangle Park, NC, APTD-1100, August 1972, pp. 4.1-4.36.

3. Condon. E.U., and Odishaw, H., Handbook of Physics, McGraw-Hill Co., New York, NY, 1958, Table 3.1, p. 6-52.

**KENTUCKY UTILITIES COMPANY**

**CASE NO. 2006-00206**

**Response to Second Data Request of Commission Staff**
**Dated August 21, 2006**

**Question No. 4**

**Responding Witness: John P. Malloy**

Q-4. Refer to the response to the Staff's First Request, Item 7(a). In its response KU states, "The 2006 $NO_x$ Compliance strategy identifies the next least-cost step in the continued compliance with environmental regulations as constructing an SCR at Ghent 2 in 2009."

a. Does KU normally employ this "next least-cost step" evaluation approach when considering its compliance with environmental regulations for not only nitrogen oxide ("$NO_x$") but also to $SO_2$ and $SO_3$ emissions? Explain the response.

b. Given the nature of current environmental regulations concerning the emissions of $NO_x$, $SO_2$, and $SO_3$, would KU agree its evaluation approach should also consider overall compliance with the environmental requirements, and not just the "next least-cost step"? Explain the response.

A-4. The 2006 $NO_x$ Compliance Strategy identified in the data request is a 30-year, least-cost study in which, as part of that study, the next least-cost compliance step can be identified.

a. No. The Company performs 20- to 30-year multi-pollutant compliance planning model studies consistent with those filed in the recent 2005 Integrated Resource Plan. These compliance plans identify the lowest long-term revenue requirement plan. However, the Company acts on portions of the plan, (i.e. the "next least cost step"), where compliance is required.

Identifying the next least-cost alternative is appropriate when environmental requirements allow compliance at one unit to be credited toward compliance at another unit (i.e. "over-complying" for $SO_2$ or $NO_x$ emissions); or, when the system-wide mandatory compliance date with an environmental regulation is far enough in the future to allow technological improvements to be incorporated into future evaluations. Each subsequent evaluation can incorporate new capital costs, expected efficiencies, operating costs, and market price impacts that were unavailable at the time the prior study was conducted, resulting in a lower cost environmental compliance plan.

The mitigation of $SO_3$ is different because it is a unit specific requirement. The operation of an $SO_3$ control technology on one unit does not eliminate the possibility of $SO_3$ influences on another unit.

b. Yes, the Company agrees that overall environmental compliance should be the evaluation approach and this approach is consistent with the Company's historical and current long range planning methodologies.

**KENTUCKY UTILITIES COMPANY**

**CASE NO. 2006-00206**

**Response to Second Data Request of Commission Staff**
**Dated August 21, 2006**

**Question No. 5**

**Responding Witness: Kent W. Blake**

Q-5. Refer to the response to the Staff's First Request, Item 8(b). The Commission has previously issued Certificates of Public Convenience and Necessity specifically for the construction of scrubbers at Ghent Units 1 and 2. Subsequent to the issuance of those certificates, KU decided to switch the Ghent Unit 1 scrubber to Unit 2 and construct a new scrubber for Unit 1. Explain in detail how KU reached the conclusion that it does not need to seek an amendment to the Certificate of Public Convenience and Necessity issued for the Ghent Unit 2 scrubber nor does it need to seek a new Certificate of Public Convenience and Necessity for the new scrubber at Ghent Unit 1.

A-5. KU regrets the confusion that has arisen with regard to this issue, and hereby clarifies as follows:

First, KU's decision to build duct work to connect the first of the two FGDs it constructed (which originally was connected to Ghent Unit 1) to Ghent Unit 2 *predated* the KU application for the second FGD in Case No. 2004-00426 and was part and parcel of KU's December 20, 2004 Application in that case. Attached to that application is a drawing dated November 23, 2004 illustrating this configuration. KU's plans are also described in the study in the record in that proceeding known as *Construction and Minor Revision of Title V Operating Permit* by Kentuckiana Engineering Company (January 2005).[3] Thus, KU did not, in fact, change the configuration that was proposed, and approved, in Case No. 2004-00426.

In summary, KU concluded that it does not need to seek an amendment to the Certificate of Public Convenience and Necessity issued for the Ghent Unit 2 FGD because the record demonstrates that KU requested and was granted a Certificate of Public Convenience and Necessity in Case No. 2004-00426 to construct a FGD at Ghent Unit 2 which would be connected to Ghent Unit 1.

Next, KU concluded that it does not need a new Certificate of Public Convenience and Necessity for the new FGD at Ghent Unit 1 because the Commission granted

[3] See KU's Response to KPSC Data Request No. 1-4 filed on February 9, 2005 in Case No. 2004-00426.

KU the authority to construct that FGD in Case No.1992-00005. KU constructed that FGD at the site specified, and for the purpose specified. The fact that the ductwork from that FGD is now being connected to Ghent Unit 2 does not change the public convenience and necessity requiring that facility, the function of that facility, or the cost of that facility. In fact, the ductwork reconfiguration more effectively utilizes the available real estate at the site and minimizes the operational difficulties associated with other arrangements. KU views the connection of the ductwork of the FGD constructed at Ghent Unit 1 to Ghent Unit 2 as an immaterial change from the construction authorized by the Commission's Order in Case No. 1992-00005. To resolve this issue, however, KU will file a motion in Case No. 1992-00005 for the limited purpose of reopening that case to amend the Certificate of Public Convenience and Necessity to reflect this minor change in the use of the facility within the next ten days.

Third, the Certificate of Public Convenience and Necessity sought in this case involves a new SCR system for Ghent Unit 2, and does not relate directly to the FGDs at Ghent Unit 1 and Ghent Unit 2 or to the Certificates authorizing the construction of those two FGDs. These FGDs have been and are being constructed pursuant to authority previously granted, with the minor deviation discussed in the paragraph above.

## KENTUCKY UTILITIES COMPANY

## CASE NO. 2006-00206

## Response to Second Data Request of Commission Staff
## Dated August 21, 2006

## Question No. 6

## Responding Witness: Kent W. Blake

Q-6. Refer to the response to the Staff's First Request, Item 15.

a. Explain in detail why KU did not include the operating and maintenance ("O&M") expenses associated with the Air Quality Control System ("AQCS") at Trimble County Unit 2 in its June 23, 2006 application.

b. Explain in detail what has changed since the filing of the June 23, 2006 application that caused KU to now seek the recovery of the Trimble County Unit 2 AQCS O&M expenses as part of its amended environmental compliance plan and amended surcharge mechanism.

c. Does KU intend to amend its application, testimony, and proposed environmental surcharge tariff to include a request to recover O&M expense for AQCS at Trimble County Unit 2?

A-6. a. The Company did not include a request for inclusion of operation and maintenance expenses associated with the AQCS at Trimble County Unit 2 in the June 23, 2006 application because such expenses would not be incurred until the unit is placed in-service in 2010. The Company intended that such expenses would be considered in future proceedings under KRS 278.183 or KRS 278.190 at a time closer to when the expenses would be incurred.

b. The only change has been the Commission Staff's Data Request in this proceeding. In response to that data request, the Company provided the information relevant to these expenses in the event the Commission wished to consider the issue of recovery of these expenses under KRS 278.183 in connection with this proceeding.

c. No. The Company provided all necessary information concerning the inclusion of O&M in its response to Commission Staff's First Request, Item 15. As noted in that response, these O&M expense estimates were consistent with the information contained in the evaluation of Trimble County Unit 2 in Case No. 2004-00507. The Company went on to respectfully request that these O&M expenses be considered in connection with the Commission's decision on the Company's application in this proceeding.

However, for the reasons included in the Company's response to Commission Staff's First Request, Item 15, the Company does not wish to delay receipt of an Order in this proceeding which the Company expects could occur in the event it were to file an amended application. In the event the Commission decides not to consider these expenses in this proceeding based on the Company's response to Commission Staff's First Request, Item 15, the Company reserves the right to seek recovery of these expenses in a subsequent filing under KRS 278.183 or KRS 278.190.

**KENTUCKY UTILITIES COMPANY**

**CASE NO. 2006-00206**

**Response to Second Data Request of Commission Staff**
**Dated August 21, 2006**

**Question No. 7**

**Responding Witness: Robert M. Conroy**

Q-7. Refer to the response to the Staff's First Request, Item 16. Prior to the Commission Staff's request, had KU prepared any analyses or modeling to determine if the proposed changes in determining R(m) would impact KU's customers? Explain the response. If no analyses or modeling were performed, explain in detail why such an analysis or modeling was not undertaken.

A-7. Yes. The analysis that was performed in determining to propose the change to R(m) was qualitative in nature. The proposed change to the determination of R(m) was made to align the revenues used to determine the environmental surcharge factor with the revenues to which the environmental surcharge factor is applied on customer bills. By aligning these revenues, the variability in the monthly true-up adjustment would be reduced. The Company did not quantify the minor impact to the jurisdictional allocation factor.

**KENTUCKY UTILITIES COMPANY**

**CASE NO. 2006-00206**

**Response to Second Data Request of Commission Staff**
**Dated August 21, 2006**

**Question No. 8**

**Responding Witness: Robert M. Conroy**

Q8. Refer to the response to the Staff's First Request, Item 19.

a. As drafted in the proposed tariff, the reference to "adjusted for the Average Month Expense already included in existing rates" applies only to depreciation and amortization expense, property taxes, and insurance expense.

(1) Given that the response to Item 19(a) focuses on the situation concerning emission allowance expense, would KU agree that the tariff language should be modified to indicate that the emission allowance expense is adjusted for the expense already included in existing rates? Explain the response.

(2) If KU agrees, provide sample tariff language addressing this item.

b. If the Commission finds in the final Order in this case that the revised surcharge tariff is effective for service rendered on and after December 22, 2006, indicate when the tariff change would appear on customer bills.

A-8. a. (1) Yes. KU agrees that the proposed tariff language should be modified.

(2) Please see the attached proposed tariff ECR. The first page is a revised Exhibit RMC-1 and the second page is a revised Exhibit RMC-2 with the proposed language contained in the definitions section under 1(e).

b. The tariff changes would appear on customer bills with the February 2007 billing cycle.

**Kentucky Utilities Company**

**Second Revision to Original Sheet No. 72**
**P.S.C. No. 13**

## ECR

## Environmental Cost Recovery Surcharge

**APPLICABLE**

In all territory served.

**AVAILABILITY OF SERVICE**

To all electric rate schedules.

**RATE**

The monthly billing amount under each of the schedules to which this mechanism is applicable, including the fuel adjustment clause, demand-side management cost recovery mechanism and STOD program cost recovery factor, shall be increased or decreased by a percentage factor calculated in accordance with the following formula. T T

$$CESF = E(m) / R(m) \qquad MESF = CESF - BESF$$

MESF = Monthly Environmental Surcharge Factor
CESF = Current Environmental Surcharge Factor
BESF = Base Environmental Surcharge Factor

Where E(m) is the jurisdictional total of each approved environmental compliance plan revenue requirement of environmental compliance costs for the current expense month and R(m) is the revenue for the current expense month as set forth below.

**DEFINITIONS**

1) For all Plans, $E(m) = [(RB/12) (ROR + (ROR - DR) (TR / (1 - TR))] + OE - BAS$ T
   Where:
   a) RB is the Total Environmental Compliance Rate Base.
   b) ROR is the Rate of Return in Environmental Compliance Rate Base, designated as the overall all rate of return [cost of short term debt, long term debt, preferred stock, and common equity] T
   c) DR is the Debt Rate [cost of short term debt, and long term debt] T
   d) TR is the Composite Federal and State Income Tax Rate. T
   e) OE is the Operating Expenses [Depreciation and Amortization Expense, Property Taxes, Emission Allowance Expense and O&M expense adjusted for the Average Month Expense already included in existing rates]. Includes operation and maintenance expense recovery authorized by the K.P.S.C. in Case Nos. 2000-439, 2002-146, 2004-00426 and 2006-00206. T T T T
   f) BAS is the total proceeds from by-product and allowance sales.

2) Total E(m) (sum of each approved environmental compliance plan revenue requirement) is multiplied by the Jurisdictional Allocation Factor to arrive at Net Jurisdictional E(m)

3) The revenue R(m) is the average monthly base revenue for the Company for the 12 months ending with the current expense month. Base revenue includes the customer, energy and demand charge for each rate schedule to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause, the Demand-Side Management Cost Recovery Mechanism and STOD Program Cost Recovery Factor as applicable for each rate schedule. T T T T T T

4) Current expense month (m) shall be the second month preceding the month in which the Environmental Surcharge is billed.

**Date of Issue: June 23, 2006**
**Canceling First Revision to Original Sheet No. 72**
**Issued June 28, 2005**

**Date Effective: With Bills Rendered On and After February 1, 2007**

**Issued By**
**John R. McCall, General Counsel and Secretary**
**Louisville, Kentucky**
**Issued by Authority of an Order of the KPSC in Case No. 2006-00206 dated**

Revised Exhibit RMC-2

**Kentucky Utilities Company**

Second Revision to Original Sheet No. 72
P.S.C. No. 13

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## ECR
## Environmental Cost Recovery Surcharge

**APPLICABLE**
In all territory served.

**AVAILABILITY OF SERVICE**
To all electric rate schedules.

**RATE**
The monthly billing amount under each of the schedules to which this mechanism is applicable, including the fuel adjustment clause, demand-side management cost recovery mechanism and STOD program cost recovery factor, shall be increased or decreased by a percentage factor calculated in accordance with the following formula.

CESF = E(m) / R(m)    MESF = CESF – BESF

MESF = Monthly Environmental Surcharge Factor
CESF = Current Environmental Surcharge Factor
BESF = Base Environmental Surcharge Factor

Where E(m) is the jurisdictional total of each approved environmental compliance plan revenue requirement of environmental compliance costs for the current expense month and R(m) is the revenue for the current expense month as set forth below.

**DEFINITIONS**

1) For all Plans, E(m) = [(RB/12) (ROR + (ROR - DR) (TR / (1 - TR))] + OE - BAS
Where:
   a) RB is the Total Environmental Compliance Rate Base.
   b) ROR is the Rate of Return in Environmental Compliance Rate Base, designated as the overall all rate of return [cost of short term debt, long term debt, preferred stock, and common equity]
   c) DR is the Debt Rate [cost of short term debt, and long term debt]
   d) TR is the Composite Federal and State Income Tax Rate.
   e) OE is the Operating Expenses [Depreciation and Amortization Expense, Property Taxes, Emission Allowance Expense and O&M expense adjusted for the Average Month Expense already included in existing rates]. Includes operation and maintenance expense recovery authorized by the K.P.S.C. in Case Nos. 2000-439, 2002-146, 2004-00426 and 2006-00206.
   f) BAS is the total proceeds from by-product and allowance sales.

2) Total E(m) (sum of each approved environmental compliance plan revenue requirement) is multiplied by the Jurisdictional Allocation Factor to arrive at Net Jurisdictional E(m)

3) The revenue R(m) is the average monthly base revenue for the Company for the 12 months ending with the current expense month. Base revenue includes the customer, energy and demand charge for each rate schedule to which this mechanism is applicable and automatic adjustment clause revenues for the Fuel Adjustment Clause, the Demand-Side Management Cost Recovery Mechanism and STOD Program Cost Recovery Factor as applicable for each rate schedule.

4) Current expense month (m) shall be the second month preceding the month in which the Environmental Surcharge is billed.

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| Date of Issue: June 23, 2006 | Issued By | Date Effective: With Bills Rendered |
| Canceling First Revision to Original Sheet No. 72, | | On and After |
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John R. McCall
General Counsel and Secretary
Louisville, Kentucky
Issued by Authority of an Order of the KPSC in Case No. 2006-00206 dated