an e·on company

Ms. Elizabeth O'Donnell
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40602-0615

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SEP 07 2006
PUBLIC SERVICE COMMISSION

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September 7, 2006

RE: *In the Matter Of: The Application Of Louisville Gas and Electric Company For Approval Of Its 2006 Compliance Plan For Recovery By Environmental Surcharge* - **Case No. 2006-00208**

Dear Ms. O'Donnell:

Enclosed please find an original and five (5) copies of Louisville Gas and Electric Company's ("LG&E") 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**

RECEIVED

SEP 07 2006

PUBLIC SERVICE COMMISSION

**In the Matter of:**

| | | |
|---|---|---|
| **THE APPLICATION OF LOUISVILLE GAS AND** | ) | |
| **ELECTRIC COMPANY FOR APPROVAL OF ITS** | ) | **CASE NO.** |
| **2006 COMPLIANCE PLAN FOR RECOVERY BY** | ) | **2006-00208** |
| **ENVIRONMENTAL SURCHARGE** | ) | |

**RESPONSE OF**
**LOUISVILLE GAS AND ELECTRIC COMPANY**
**TO**
**SECOND DATA REQUEST OF**
**COMMISSION STAFF**
**DATED AUGUST 21, 2006**

**FILED: SEPTEMBER 7, 2006**

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2006-00208**

**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 1(b) and 1(d). Explain why Paddy's Run Units 12 and 13 appear in the estimated nitrogen oxide ("$NO_X$") allowance schedules but not in the schedules of actual 2005 or estimated 2006 emissions.

A-1. The combustion turbines at Paddy's Run (and Trimble County) appear collectively in the schedule of actual 2005 and estimated 2006 emissions as "Peakers." The units have very low emissions and receive minimal allowances and were grouped together as "Peakers".

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2006-00208

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 2.

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 LG&E 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 LG&E'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 <u>requirements</u> under the Act that mandate the mitigation of $SO_3$ emissions and LG&E 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) standards specified in 401 KAR 61:015 and LMAPCD Regulation 7.06. Plume "touchdowns" can potentially pose a hazard to human health or the environment. Clearly, as indicated in the response to Question 2(a), both KDAQ and USEPA have

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[1] Citing <u>New York et al. v. EPA</u>, 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.

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).

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2006-00208**

**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 2(d). In this response, LG&E states,

> The findings in the Sargent and Lundy $SO_3$ Mitigation Study, Exhibit JPM-3, 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-3 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 LG&E agree that, based upon the statements from Exhibit JPM-3, 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-3 shows a chart relating flue gas $SO_3$ concentration with estimated plume opacity for different stack diameters.

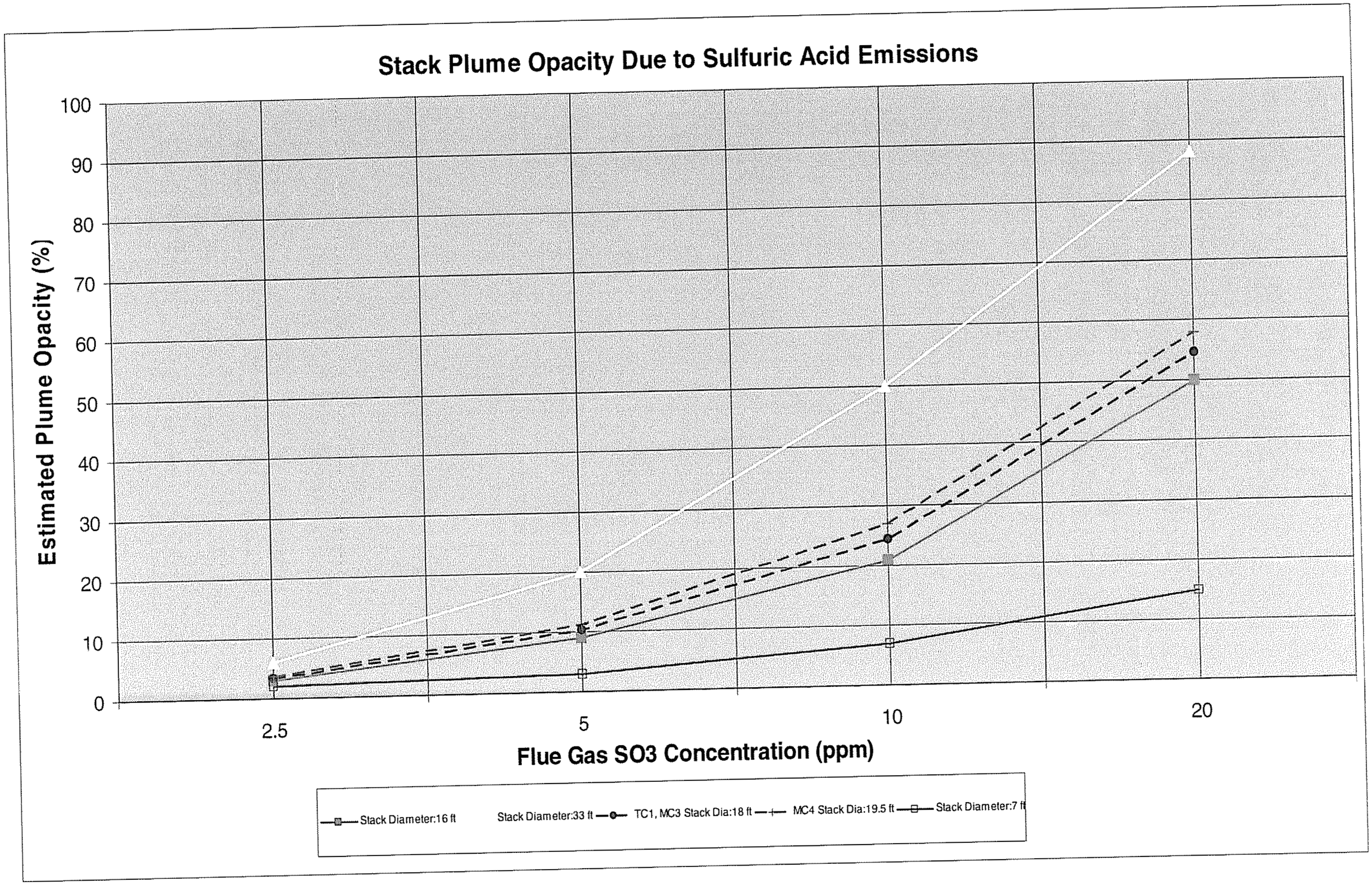
What are the diameters of the stacks at Mill Creek Units 3 and 4 and Trimble County Unit 1?

c. Provide copies of the Environmental Protection Agency's Method 9 protocols referenced in the response to Item 2(d).

A3. 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-3, 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 Mill Creek and Trimble stack diameter curves can be plotted on the graph (see Attachment). 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 20% (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 the Trimble and Mill Creek Stations. However, final operational control parameters will be established through testing and calibration for each unit and application of USEPA Method 9 testing.

b. The Mill Creek Unit 3 stack diameter is 18 feet.
The Mill Creek Unit 4 stack diameter is 19.5 feet.
The Trimble County Unit 1 stack diameter is 18 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.




Attachment to Response to Question 3(a)
Page 1 of 1
Malloy

EMISSION MEASUREMENT TECHNICAL INFORMATION CENTER
NSPS TEST METHOD

Prepared by **Emission Measurement Branch**
Technical Support Division, OAQPS, EPA

**EMTIC TM-009**
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 ______________________________

| Hr | Min | Seconds 0 | 15 | 30 | 45 | Steam plume (check if applicable) Attached | Detached | Comments |
|---|---|---|---|---|---|---|---|---|
| | 0 | | | | | | | |
| | 1 | | | | | | | |
| | 2 | | | | | | | |
| | 3 | | | | | | | |
| | 4 | | | | | | | |
| | 5 | | | | | | | |
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**Figure 9-2. Observation record (continued).**

Page ___ of ___

Company ______________________________ Observer ______________________________

Location ______________________________ Type facility ______________________________

Test Number ______________________________ Point of emissions ______________________________

| Hr | Min | Seconds 0 | 15 | 30 | 45 | Steam plume (check if applicable) Attached | Detached | Comments |
|---|---|---|---|---|---|---|---|---|
| | 30 | | | | | | | |
| | 31 | | | | | | | |
| | 32 | | | | | | | |
| | 33 | | | | | | | |
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| | 35 | | | | | | | |
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| | 59 | | | | | | | |

**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 $\pm 5$ 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.

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**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2006-00208**

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

**Question No. 4**

**Responding Witness: Kent W. Blake**

Q-4. Refer to the response to the Staff's First Request, Item 9.

a. Explain in detail why LG&E 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 LG&E 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 LG&E intend to amend its application, testimony, and proposed environmental surcharge tariff to include a request to recover O&M expenses for AQCS at Trimble County Unit 2?

A-4. 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 9. 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 9, 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 9, the Company reserves the right to seek recovery of these expenses in a subsequent filing under KRS 278.183 or KRS 278.190.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2006-00208**

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

**Question No. 5**

**Responding Witness: Kent W. Blake / Shannon L. Charnas**

Q-5. Refer to the response to the Staff's First Request, Item 11(b).

a. Provide the original cost and accumulated depreciation associated with the Mill Creek stack opacity monitors that were replaced by the installation of the new particulate monitors, as reflected in LG&E's surcharge calculations.

b. Provide the depreciation expense, property taxes, insurance expense, and any O&M expense associated with the replaced Mill Creek stack opacity monitors, as reflected in LG&E's surcharge calculations.

c. Does LG&E's approved environmental compliance plan include provisions for operational inventory or mobile test units? Explain the response.

d. If the Mill Creek stack opacity monitors are no longer operating as part of the capital investment associated with LG&E's environmental compliance plan, explain in detail why LG&E believes there is no need to adjust the surcharge calculations for this removal.

A-5. a. The Mill Creek stack opacity monitors are not part of the environmental compliance rate base. Therefore, there are no costs associated with this equipment reflected in LG&E's surcharge calculation.

b. See the response to Part a.

c. No. LG&E has not sought approval for the inclusion of operational inventory or mobile test units. The Mill Creek stack opacity monitors are not included in the Company's environmental compliance plan or the environmental compliance rate base.

d. The Mill Creek stack opacity monitors are not included as part of LG&E's compliance plan. They are part of the cost of service used in the determination of base rates and will remain a part of that cost of service as inventory available for use at other facilities as needed. Therefore, no adjustment to the ECR rate base is necessary.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2006-00208**

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

**Question No. 6**

**Responding Witness: Robert M. Conroy**

Q-6. Refer to the response to the Staff's First Request, Item 11. Prior to the Commission Staff's request, had LG&E prepared any analyses or modeling to determine if the proposed changes in determining R(m) would impact LG&E'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-6. 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 the 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.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2006-00208**

**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 14. 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-7. The tariff changes would appear on customer bills with the February 2007 billing cycle.