Attachment C:

Evaluation of the Impact of Sandy Creek Energy Station SO_2 Emissions

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Attachment C, Part 1:

TCEQ's Evaluation of SO_2 Levels in McLennan County

TCEQ's Evaluation of SO_2 Levels in McLennan County

Sandy Creek Energy Station – McLennan County, TX

The Texas Commission on Environmental Quality (TCEQ) evaluated the impact of the Sandy Creek Energy Station sulfur dioxide (SO_2) emissions along with McLennan County SO_2 emissions with the use of monitoring data. Past and recent monitored data from the Waco Mazanec C1037 air quality monitor show McLennan County has been, and is still, attaining the 2010 SO_2 NAAQS. Sandy Creek is the only major SO_2 emissions source identified by the United States Environmental Protection Agency (EPA) in McLennan County. Due to McLennan County monitoring data showing compliance, the TCEQ determined that SO_2 emissions from Sandy Creek Energy Station do not significantly impact attainment of the 2010 SO_2 NAAQS in McLennan and nearby counties.

- The TCEQ has one monitor, Waco Mazanec C1037, in McLennan County that measures SO_2 concentrations. The 2014 SO_2 design value for this station is 6 parts per billion (ppb), which is well below the 75 ppb SO_2 NAAQS. Southerly winds prevail in the Waco area. The SO_2 monitor is located approximately 14 miles to the northwest of the Sandy Creek Energy Station. As a result, the Waco Mazanec monitor is downwind of the energy station in prevailing weather conditions. This indicates that the Sandy Creek Energy Station does not significantly impact attainment of the 2010 SO_2 NAAQS in McLennan County or other counties downwind of the facility.

Sandy Creek Energy Station has submitted additional information, including its own modeling results, to EPA Region 6. The modeling results provide additional evidence that the facility demonstrates compliance with the 2010 SO_2 NAAQS. Sandy Creek's determination of compliance for the facility provides additional information in support of an attainment designation for McLennan County.

- By letter dated June 12, 2015 to Ms. Wren Stenger of EPA Region 6, Sandy Creek Energy Station submitted information to the EPA for consideration in making designations for the 2010 SO_2 NAAQS, including: copies of the site's air quality permit; Sandy Creek Energy Station's April 5, 2013 petition to the EPA Clean Markets Division for an Alternate Emissions Reporting Methodology; and a modeling analysis for one-hour average ambient SO_2 concentrations. This attachment contains copies of the additional information submitted to the EPA by Sandy Creek in 2013 and 2015.

Sandy Creek Energy Station should not have been included in the list of sites identified in the EPA's March 20, 2015 letter. The 2012 SO_2 emissions data for Sandy Creek Energy Station cited by the EPA is substituted emissions data, not actual measured data, and greatly over-estimates the emissions for the facility. Sandy Creek's estimate of actual emissions, taking into account controls and actual conditions, is 25.6 tons, whereas the substituted emissions data used was 4,954.8 tons.

- While the 2012 SO_2 emissions data for Sandy Creek Energy Station in the EPA Clean Air Markets Division's Air Market Program Database is numerically over the threshold that the EPA agreed to in the consent decree approved by the Court on March 2, 2015, this emission data grossly overstates the actual SO_2 emissions from the facility in 2012. The Sandy Creek Energy Station facility commenced operations on November 24, 2012; however, the unit's continuous emissions monitoring system (CEMS) was not installed and certified until March 2013. In accordance with 40 Code of Federal Regulations (CFR) Part 75 monitoring requirements, Sandy Creek Energy State followed the specified data substitution requirements for reporting emissions to EPA from November 2012 through March 2013. However, the data substitution requirements lead to greatly over-estimated 2012 emissions for Sandy Creek. Actual 2012 SO_2 emissions for the Sandy Creek Energy Station coal-fired unit are estimated to be only about 26 tons. Actual monitored SO_2 emissions data after the certification of the facility's CEMS shows the SO_2 emission rate to be less than 0.1 pound per million British thermal units (lb/MMBtu), which is less than one-tenth the 1.137 lb/MMBtu determined from the 40 CFR Part 75 substituted emissions data reported to the Air Markets Program for 2012.

- As allowed by 40 CFR Part 75, §75.4(d)(4), Sandy Creek Energy Station submitted a petition for an alternate methodology for reporting substituted emission data on April 5, 2013 to Mr. Reid Harvey, Acting Director of the EPA Clean Air Markets Division. As far as the TCEQ is aware, the EPA has not yet acted on Sandy Creek Energy Station's petition. If the alternate methodology proposed by Sandy Creek Energy Station is approved by EPA and used to determine the facility's emissions for the time period requested, the 2012 SO_2 emissions reported to the Air Markets Program would be an estimated 2,280 tons. This estimate still overstates emissions because the methodology assumes maximum potential concentration (i.e., no SO_2 pollution controls) and maximum potential flow rate for the 270 hours that the unit fired coal fuel. If the EPA had acted on Sandy Creek Energy Station's petition and approved the proposed methodology in a timely manner, the reported 2012 emissions in the Air Markets Program Database would have been under the 2,600-ton threshold specified in the consent decree.

Sandy Creek Energy Station is a modern coal-fired power plant with a flue gas desulfurization (FGD) scrubber and stringent permit restrictions on SO_2 emissions.

- The coal-fired utility boiler located at Sandy Creek Energy Station is equipped with a dry FGD scrubber for SO_2 control. The unit is limited by permit to firing only low sulfur subbituminous coal with a sulfur content not to exceed 0.60 lb/MMBtu of heat input. The facility's permit conditions not only limit SO_2 emissions on both a pound per hour and ton per year basis, but also on lb/MMBtu basis. The unit's SO_2 emissions are limited to 0.10 lb/MMBtu on a 12-month rolling average basis and 0.12 lb/MMBtu on a 30-day rolling average basis.

Attachment C:

TCEQ's Evaluation of the Impact of Sandy Creek Energy Station SO_2 Emissions

Part 2:

Additional Supporting Information for Sandy Creek Energy Station

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(254) 896-4205 tel.
(254) 896-7726 fax.

File No. 20.1.2.1

Certified Delivery

June 12, 2015

Ms. Wren Stenger
Director, Multimedia Planning and Permitting Division
U.S. EPA, Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

Re: Area Designations for One-Hour SO_2 NAAQS
Sandy Creek Energy Station, McLennan County, Texas

Letter No.: SCS-EPA-0002

Dear Director Stenger:

The purpose of this letter is to provide the U.S. Environmental Protection Agency ("EPA") with information for consideration in its attainment designations implementing the revised National Ambient Air Quality Standard ("NAAQS") for sulfur dioxide ("SO_2") for the area surrounding the Sandy Creek Energy Station located in McLennan County, Texas. This information is submitted on behalf of Sandy Creek Services, LLC ("Sandy Creek"), the operator of the Sandy Creek Energy Station. Sandy Creek believes this information uncontrovertibly supports a determination that the area around the Sandy Creek Energy Station should be designated attainment.

Regulatory Background

In 2010, the EPA revised the primary SO_2 NAAQS by establishing a new one-hour standard. In 2011 and 2012, Governor Perry recommended that EPA designate McLennan County as in attainment with the new standard. The EPA published final nonattainment area designations for 29 areas in 16 states in 2013 for which ambient monitoring data identified exceedances, which did not include any county in Texas. *See* 78 Fed. Reg. 47,191 (Aug. 5, 2013). For the rest of the Nation, EPA proposed to await the development of information necessary to make supportable designations. *See* 79 Fed. Reg. 27,446 (May 13, 2014) (proposed "Data Requirements Rule" directing state agencies "to provide data to characterize current air quality in areas with large sources of SO_2 emissions…"). But under the terms of a March 2015 consent decree, EPA agreed to complete certain area designations by July 2, 2016. *See Sierra Club, et al., v. McCarthy*, No. 13-CV-03953-SI, N.D. Cal. (order entering consent decree issued Mar. 2, 2015). Accordingly, on March 20, 2015, the EPA Office of Air Quality Planning and Standards Director, Stephen Page, effectively directed compliance with the Data Requirements Rule. In that memorandum, Director Page asks the EPA Regions to ensure that each state with an identified area submit to EPA by September 18, 2015, information sufficient to allow for an appropriate designation of the area by the court ordered deadline of July 2, 2016.

Under the March 2015 consent decree, EPA is to designate by July 2, 2016 any areas containing a stationary source that in 2012 emitted more than 2,600 tons of SO_2 and had an annual average emission rate of at least 0.45 lbs SO_2/MMBtu. According to a posted listing, http://epa.gov/airquality/sulfurdioxide/designations/pdfs/sourceareas.pdf, the Sandy Creek Energy Station meets these criteria. This listing of the Sandy Creek Energy Station is based on incomplete or misleading information concerning its actual and potential emissions. The information provided in this letter addresses the incomplete and misleading emissions data. Once this additional data is considered, any concern that the Sandy Creek Energy Station could be responsible for exceedances of the revised SO_2 standard should be eliminated.

EPA is Using an Estimate of 2012 Emissions Several Factors Too High.

The Sandy Creek Energy Station, commissioned in November 2012, is one of the Nation's best-controlled and lowest-emitting coal-fired power plants. Its main boiler fires low-sulfur coal from the Powder River Basin and uses a dry scrubber (spray dryer absorber with lime injection) to achieve a minimum 90% SO_2 removal efficiency. Its permit-allowable maximum SO_2 emission rate of 0.12 lb/MMBtu (30-day rolling average) is barely one-quarter of the EPA's screening criteria for coal-fired power plants requiring attention in this phase of designation, 0.45 lb/MMBtu. A copy of the Sandy Creek Energy Station's permit is provided as Exhibit A.

The listing of the Sandy Creek Energy Station is premised on an EPA finding that the Sandy Creek Energy Station emitted 1.14 lb/MMBtu of SO_2 in 2012, which is among the highest rates on the list of 69 sources listed for further attention. This finding, however, is in error, an artifact of 40 CFR Part 75 data substitution procedures for the 29 days during which the Sandy Creek Energy Station operated in 2012. Part 75 instruct sources to use substituted emissions data based on the theoretical maximum potential pollutant concentration that could result from in sub-optimal combustion conditions. The substitute data is not an accurate reflection of the actual (or allowable) emissions for that 29-day period, or any other.

More specifically, the Sandy Creek Energy Station was in shakedown mode until the certification of its continuous emission monitoring system ("CEMS") was completed in March 2013. In order to estimate emissions during that pre-certification period solely for purposes of the Acid Rain Program, Sandy Creek used Part 75 data substitution procedures. *See* 40 C.F.R. § 75.4(d)(1). These procedures grossly and artificially inflated the estimated emissions far beyond permit limits or actual emissions levels in several respects:

- Assumed heat input rate of 18,046 MMBtu/hour versus permit limit of 8,185 MMBtu/hour; and
- Assumed SO_2 emission rate of 1.14 lb/MMBtu versus permit limit 30-day rolling average 0.12 lb/MMBtu.

The net result of these assumptions made for the Acid Rain Database emission estimate for 2012 (4954.8 tons) are far in excess of the actual emissions (25.6 tons). The actual emissions were especially low because for the entire time that the Sandy Creek Energy Station was on-line in 2012 (587 total hours), the Sandy Creek Energy Station was firing on low-sulfur natural gas both for start-up, shutdown (317 hours) and also for co-firing with coal (270 hours) (documentation provided in Exhibit B).

The net result of this artifact of data substitution was an extreme divergence between the emissions rate reported to the Acid Rain Database for 2012 (1.14 lb/MMBtu) and the actual emission rate (0.039 lb/MMBtu) for that year. Further documentation of this overestimation was presented in a 2013 petition to EPA's Clean Air Markets Division, by which Sandy Creek sought relief from the added allowance costs associated with this excessively conservative estimate of actual emissions (copy provided as Exhibit C).

Actual emissions during the first two full years of regular operation for which certified CEMS is available (March 2013-March 2015) provide confirmation that the Sandy Creek Energy Station is a very low-emitting coal-fired electric generating unit. The annual average SO_2 emissions for 2013, 2014, and 2015 (through April) were 0.10, 0.078, and 0.084 lb/MMBtu, respectively. Based on this clarification and correction of the Sandy Creek Energy Station's actual and potential emissions, Sandy Creek respectfully submits that the Sandy Creek Energy Station requires no further evaluation because its emissions are substantially below the threshold set by EPA policy for identifying high-risk sources.

Modeling Already Has Confirmed that the Sandy Creek Energy Station's Emissions Pose no Threat to the One-Hour SO2 NAAQS

In 2011, Sandy Creek commissioned a modeling assessment to evaluate the possible implications of the newly adopted one-hour NAAQS (report provided as Exhibit D). Sandy Creek's contractor, Zephyr Environmental Corporation ("Zephyr"), modeled the Sandy Creek Energy Station's maximum permitted 1-hour SO_2 emission rate (0.30 lb/MMBtu) through five years of Waco meteorological data using AERMOD. The highest modeled contribution of the Sandy Creek Energy Station to any off-property receptor was 117 μg/m3. For the background concentration, Zephyr used the three-year average of the 99th percentile of the measured daily maximum one-hour concentrations during the period 2008 – 2010 at the Mazanec monitoring station located in Elm Mott, Texas (EPA Site No. 48-309-1037), the CAMS site nearest to the Sandy Creek Energy Station's location. Adding that concentration of 16.8 μg/m3 yielded a maximum of 134 μg/m3, comfortably below the NAAQS of 196 μg/m3, despite following these very conservative assumptions:

- Assumes coincidence of worst-case *permitted* one-hour emission rate with worst-case one-hour dispersion conditions over the five-year period;

- Assumes that the 99th percentile measured concentration of SO_2 in McLennan County (used as background) would be coincident with the highest emissions rate and worst-case meteorology at maximum receptor;

- Assumes all receptors are accessible and populated (EPA guidance allows for discounting receptors at which monitors are incapable of being placed).

1-Hour SO_2 Designation for McLennan County

Based on the information provided by this letter, Sandy Creek believes it should be demonstrably clear that the Sandy Creek Energy Station does not belong on any list of facilities that pose any risk of causing or contributing to SO_2 NAAQS exceedances. Further, the area warrants a designation of attainment, not only because there are no measured exceedances of the NAAQS, but modeling confirms that none would result from operation of the Sandy Creek Energy Station even at its maximum allowable emission rates.

Please call me at 908-239-3974 to convey any questions that remain.

Sincerely,

Kathy French

Kathy French
Vice President, Environmental
LS Power Development, LLC

cc: Mr. Guy Donaldson
U.S. EPA, Region 6
Multimedia and Permitting Division
1445 Ross Avenue, Suite 1200
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Mr. Steve Hagle, MC 122
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Texas Commission on Environmental Quality
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TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
AIR QUALITY PERMIT

A Permit Is Hereby Issued To
Sandy Creek Services, LLC
Authorizing the Construction and Operation of the
Sandy Creek Energy Station
Located at **Riesel, McLennan County, Texas**
Latitude 31° 28′ 27″ Longitude –96° 57′ 18″

Permits: 70861 and PSDTX1039

Revision Date : November 21, 2014

Expiration Date: July 18, 2016

For the Commission

1. **Facilities** covered by this permit shall be constructed and operated as specified in the application for the permit. All representations regarding construction plans and operation procedures contained in the permit application shall be conditions upon which the permit is issued. Variations from these representations shall be unlawful unless the permit holder first makes application to the Texas Commission on Environmental Quality (commission) Executive Director to amend this permit in that regard and such amendment is approved. [Title 30 Texas Administrative Code 116.116 (30 TAC 116.116)]
2. **Voiding of Permit**. A permit or permit amendment is automatically void if the holder fails to begin construction within 18 months of the date of issuance, discontinues construction for more than 18 months prior to completion, or fails to complete construction within a reasonable time. Upon request, the executive director may grant an 18-month extension. Before the extension is granted the permit may be subject to revision based on best available control technology, lowest achievable emission rate, and netting or offsets as applicable. One additional extension of up to 18 months may be granted if the permit holder demonstrates that emissions from the facility will comply with all rules and regulations of the commission, the intent of the Texas Clean Air Act (TCAA), including protection of the public's health and physical property; and (b)(1)the permit holder is a party to litigation not of the permit holder's initiation regarding the issuance of the permit; or (b)(2) the permit holder has spent, or committed to spend, at least 10 percent of the estimated total cost of the project up to a maximum of $5 million. A permit holder granted an extension under subsection (b)(1) of this section may receive one subsequent extension if the permit holder meets the conditions of subsection (b)(2) of this section. [30 TAC 116.120(a), (b) and (c)]
3. **Construction Progress**. Start of construction, construction interruptions exceeding 45 days, and completion of construction shall be reported to the appropriate regional office of the commission not later than 15 working days after occurrence of the event. [30 TAC 116.115(b)(2)(A)]
4. **Start-up Notification**. The appropriate air program regional office shall be notified prior to the commencement of operations of the facilities authorized by the permit in such a manner that a representative of the commission may be present. The permit holder shall provide a separate notification for the commencement of operations for each unit of phased construction, which may involve a series of units commencing operations at different times. Prior to operation of the facilities authorized by the permit, the permit holder shall identify the source or sources of allowances to be utilized for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program). [30 TAC 116.115(b)(2)(B)(iii)]
5. **Sampling Requirements**. If sampling is required, the permit holder shall contact the commission's Office of Compliance and Enforcement prior to sampling to obtain the proper data forms and procedures. All sampling and testing procedures must be approved by the executive director and coordinated with the regional representatives of the commission. The permit holder is also responsible for providing sampling facilities and conducting the sampling operations or contracting with an independent sampling consultant. [30 TAC 116.115(b)(2)(C)]

6. **Equivalency of Methods.** The permit holder must demonstrate or otherwise justify the equivalency of emission control methods, sampling or other emission testing methods, and monitoring methods proposed as alternatives to methods indicated in the conditions of the permit. Alternative methods shall be applied for in writing and must be reviewed and approved by the executive director prior to their use in fulfilling any requirements of the permit. [30 TAC 116.115(b)(2)(D)]
7. **Recordkeeping.** The permit holder shall maintain a copy of the permit along with records containing the information and data sufficient to demonstrate compliance with the permit, including production records and operating hours; keep all required records in a file at the plant site. If, however, the facility normally operates unattended, records shall be maintained at the nearest staffed location within Texas specified in the application; make the records available at the request of personnel from the commission or any air pollution control program having jurisdiction; comply with any additional recordkeeping requirements specified in special conditions attached to the permit; and retain information in the file for at least two years following the date that the information or data is obtained. [30 TAC 116.115(b)(2)(E)]
8. **Maximum Allowable Emission Rates**. The total emissions of air contaminants from any of the sources of emissions must not exceed the values stated on the table attached to the permit entitled "Emission Sources--Maximum Allowable Emission Rates." [30 TAC 116.115(b)(2)(F)]
9. **Maintenance of Emission Control**. The permitted facilities shall not be operated unless all air pollution emission capture and abatement equipment is maintained in good working order and operating properly during normal facility operations. The permit holder shall provide notification for upsets and maintenance in accordance with 30 TAC 101.201, 101.211, and 101.221 of this title (relating to Emissions Event Reporting and Recordkeeping Requirements; Scheduled Maintenance, Startup, and Shutdown Reporting and Recordkeeping Requirements; and Operational Requirements). [30 TAC 116.115(b)(2)(G)]
10. **Compliance with Rules**. Acceptance of a permit by an applicant constitutes an acknowledgment and agreement that the permit holder will comply with all rules, regulations, and orders of the commission issued in conformity with the TCAA and the conditions precedent to the granting of the permit. If more than one state or federal rule or regulation or permit condition is applicable, the most stringent limit or condition shall govern and be the standard by which compliance shall be demonstrated. Acceptance includes consent to the entrance of commission employees and agents into the permitted premises at reasonable times to investigate conditions relating to the emission or concentration of air contaminants, including compliance with the permit. [30 TAC 116.115(b)(2)(H)]
11. **This** permit may not be transferred, assigned, or conveyed by the holder except as provided by rule. [30 TAC 116.110(e)]
12. **There** may be additional special conditions attached to a permit upon issuance or modification of the permit. Such conditions in a permit may be more restrictive than the requirements of Title 30 of the Texas Administrative Code. [30 TAC 116.115(c)]
13. **Emissions** from this facility must not cause or contribute to a condition of "air pollution" as defined in Texas Health and Safety Code (THSC) 382.003(3) or violate THSC 382.085. If the executive director determines that such a condition or violation occurs, the holder shall implement additional abatement measures as necessary to control or prevent the condition or violation.
14. **The** permit holder shall comply with all the requirements of this permit. Emissions that exceed the limits of this permit are not authorized and are violations of this permit.

Special Conditions

Permit Numbers 70861 and PSDTX1039

Emission Rates and Permit Representations

1. This permit covers only those sources of emissions listed in the attached table entitled "Emission Sources - Maximum Allowable Emission Rates," and those sources are limited to the emission limits and other conditions specified in that attached table. Compliance with the annual emission limits shall be based on throughput for a rolling 12-month year rather than the calendar year.

2. Emission limits are based upon permit representations in the:

   A. application dated January 9, 2004 as updated March 10, 2005;

   B. alteration or amendment requests dated: December 14, 2010; February 8, 2011, (with subsequent updates); July 18, 2011 (with subsequent January 26, 2012 update); January 9, 2012; December 5, 2012; July 22, 2014; and September 12, 2014.

Federal Applicability

3. The pulverized coal (PC) boiler, identified as emission point number (EPN) S01, shall comply with applicable requirements of EPA regulations in 40 Code of Federal Regulations (CFR) as follows:

   A. Part 60, Standards of Performance for New Stationary Sources, Subpart A, General Conditions, and Subpart Da, Standards of Performance for Electric Utility Steam Generating Units; and

   B. Part 63, National Emission Standards for Hazardous Air Pollutants, Subpart UUUUU for Electric Utility Steam Generating Units, as adopted.

4. The auxiliary boiler, identified as EPN S02, shall comply with the applicable requirements of 40 CFR Part 60, Subpart A, and Subpart Db, Standards of Performance for Industrial, Commercial, and Institutional Boilers.

5. The coal processing, storage and conveying facilities, identified as EPNs S03a, S03b, S05, S06, and S09 through S13, shall comply with the applicable requirements of 40 CFR Part 60, Subpart A, and Subpart Y, Standards of Performance for Coal Preparation Plants.

6. If any condition of this permit is more stringent than the regulations identified in Special Conditions No. 3 through 5, then for the purposes of complying with this permit, the permit shall govern and be the standard by which compliance shall be demonstrated.

Fuel Specifications, Operating Limitations, Performance Standards, and Construction Specifications

7. Fuel fired in the PC Boiler, EPN S01, shall be limited to:

   A. Low sulfur subbituminous coal with:

      (1) Sulfur content not to exceed a 12-month rolling average of 0.60 pound per million British thermal units (lb/MMBtu) of heat input and with the heat input based on fuel higher heating value (HHV); and

      (2) trace metal concentrations not to exceed, on a 12-month rolling average basis, the concentration limitations identified in Attachment A of this permit.

   B. Pipeline quality natural gas.

   C. Use of any other fuel will require prior approval from the permitting authority.

   D. Upon request by the Executive Director of the Texas Commission on Environmental Quality (TCEQ) or any air pollution control program having jurisdiction, the holder of this permit shall provide a sample and/or an analysis of the fuel fired in the PC Boiler, or shall allow air pollution control agency representatives to obtain a sample for analysis.

8. The PC Boiler shall be limited to a maximum heat input of 8,185 MMBtu/hr, averaged over a 12-month rolling period, based on the HHV of the fuel fired. **(11/14)**

9. Opacity of emissions from EPN S01 must not exceed 10 percent, averaged over a six-minute period, except for those periods described in Title 30 Texas Administrative Code § 111.111(a) (1)(E) [30 TAC § 111.111(a)(1)(E)].

10. Emissions from EPN S01 shall not exceed the performance standards in the following tables.

A. Standards demonstrated by Continuous Emissions Monitoring Systems (CEMS)

Pollutant[1]	Performance Standard (lb/MMBtu)[2]	Compliance Averaging Period
NO_x	0.070	30-day rolling
NO_x	0.050	12-month rolling
SO_2	0.12	30-day rolling
SO_2	0.10	12-month rolling
CO	0.15	12-month rolling
	not lb/MMBtu:	
Hg **(6/12)**	1.0 (10^{-5}) lb/MWh	12-month rolling[3]
NH_3	10 ppm	hourly
NH_3	3 ppm	12-month rolling

B. Standards demonstrated by Test Method[4] (TM) or SW-846 testing

Pollutant[1]	Performance Standard (lb/MMBtu)[2]	Compliance Demonstration Period
PM/PM_{10} (filterable)	0.015	annual
PM/PM_{10} total[5]	0.030	annual
VOC	3.6 (10^{-3})	annual
Organic HAP[6]	2.4 (10^{-4})	annual
H_2SO_4	3.7 (10^{-3})	annual
HCl	2.7 (10^{-4})	annual
HF **(11/14)**	2.4 (10^{-4})	annual
Halogenated Acid HAPs	3.0 (10^{-4})	annual

Notes:
[1]NO_x - nitrogen oxides
SO_2 - sulfur dioxide
CO - carbon monoxide
Hg – mercury
NH_3 – ammonia
PM - particulate matter
PM_{10} - PM $\leq$10 µm in diameter
VOC - volatile organic compounds
HAPs - hazardous air pollutants
H_2SO_4 - sulfuric acid mist
HCl - hydrogen chloride
HF - hydrogen fluoride
Halogenated Acid HAP - combined HF and HCl emissions

[2]lb/MMBtu - pounds of emissions per million Btu of heat input. Heat input is based on fuel HHV.

lb/MWh - pounds of emission per gross megawatt-hour of electricity output.

ppm - parts per million by volume, dry, adjusted to 5% oxygen (O_2).

[3] Or other averaging period specified by EPA.

[4] TM - EPA Test Methods, based on the average of three stack sampling runs to be conducted as prescribed by Special Conditions No. 30 and 39.

[5] Total PM/PM_{10} including back-half (condensibles) catch of sampling train.

[6] Organic HAP emissions are the total of the organic species listed in Section 112(b)(2) of the Federal Clean Air Act (less the organic compounds identified in 40 CFR 63, Subpart C), as measured using: EPA SW 846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Method 0031 for volatile organic HAP and Method 0010 for semi-volatile organic HAP; and EPA Other Test Method 029 (OTM-029) for hydrogen cyanide or other method as determined by Special Condition No. 31.B.

11. During any consecutive 12-month period, plant-wide emissions of HAP listed in Section 112 of the Federal Clean Air Act from the Sandy Creek Energy Station (SCES) shall be less than: **(6/12)**

    A. 10 tons per year of any single HAP; and

    B. 25 tons per year of all HAP combined.

12. In the event that the CEMS for NO_x or SO_2 are not operating for a period longer than one hour, the permit holder shall operate at no less than the ammonia feed rate to the selective catalytic reduction (SCR) system and the sorbent feed rate to the flue gas desulfurization system that were established during a successful initial performance test (adjusted for load) or at the feed rates that were measured prior to the loss of the CEMS, whichever feed rates are higher.

13. The holder of this permit shall operate the PC Boiler and associated air pollution control equipment in accordance with good air pollution control practice to minimize emissions during startup and shutdown, by operating in accordance with a written startup and shutdown plan. The plan shall include detailed procedures for review of relevant operating parameters of the PC Boiler and associated air pollution control equipment during startup and shutdown to make adjustments and corrections to reduce or eliminate any excess emissions. The plan shall also address

readily foreseeable startup scenarios, including hot startups, when the operation of the boiler is only temporarily interrupted, and provide for appropriate review of the operational condition of the boiler before initiating startup.

14. The PC Boiler Stack, EPN S01, will be approximately 360 feet tall with an exit diameter of 28 feet. Stack sampling ports and platform(s) shall be constructed on the stack as specified in the attachment entitled "Chapter 2, Stack Sampling Facilities," or an alternate design may be required at a later date if determined necessary by the Director of the TCEQ Waco Regional Office. Adequate advance notice shall be provided by TCEQ if an alternate design is required.

15. The auxiliary boiler, identified as EPN S02, shall meet the following specifications:

    A. Emissions of NO_x shall not exceed 9 ppmv, dry, corrected to 3% O_2, averaged over 3 hours of operation.

    B. Opacity of emissions shall not exceed 10 percent.

    C. Fuel shall be limited to pipeline quality natural gas.

    D. After commercial operation of the PC boiler, EPN S02 operation shall be limited to a maximum of 500 hours per year. **(6/12)**

16. The 1500 kW emergency diesel fuel-fired electric generator, identified as EPN S33, shall meet the following specifications: **(6/12)**

    A. The engine shall be certified by the manufacturer to comply with the applicable emission specifications of 40 CFR 60, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

    B. Fuel shall be limited to diesel engine fuel containing no more than 15 ppm by weight sulfur. Purchased diesel engine fuel shall comply with the EPA standards for nonroad diesel fuel in 40 CFR 80, Regulation of Fuels and Fuel Additives, in effect at the time of purchase.

    C. Operation for maintenance and testing shall be limited to a maximum of 100 hours per year.

17. The 403 hp emergency diesel fuel-fired fire water pump, identified as EPN S34, shall meet the following specifications: **(6/12)**

A. The engine shall be certified by the manufacturer to comply with the applicable emission specifications of 40 CFR 60, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

B. Fuel shall be limited to diesel engine fuel containing no more than 15 ppm by weight sulfur. Purchased diesel engine fuel shall comply with the EPA standards for nonroad diesel fuel in 40 CFR 80, Regulation of Fuels and Fuel Additives, in effect at the time of purchase.

C. Operation shall be limited to a maximum of 100 hours per year unless a greater number of hours of operation is required to fight a fire.

Chemical and Fuel Storage

18. Aqueous ammonia storage tanks shall be located within a physical barrier to traffic. Tank containment shall be employed with a minimum of 110% of tank volume.

19. Audio, olfactory, and visual checks for ammonia and water treatment chemical leaks shall be made once per shift within the operating area.

A. No later than one hour following detection of a leak, plant personnel shall take the following actions:

(1) Locate and isolate the leak.

(2) Use a leak collection or containment system to control the leak until repair or replacement can be made.

B. Within 24 hours of detection of a leak, plant personnel shall commence repair or replacement of the leaking component as appropriate.

20. In any consecutive 12-month period, the holder of this permit shall not receive more than the following quantities of diesel fuel:

Tank Number	12-month throughput
S36	240,000
S37	50,000
S38	2,500

Material Handling Operating Limitations and Standards

21. Annual coal received at the Sandy Creek site shall not exceed 4.37 million tons per calendar year. Coal shall be delivered at the rail car unloading building which shall be partially enclosed as described in the application.

22. If spontaneous combustion occurs in a coal stockpile, plant personnel will begin efforts as soon as possible to extinguish the fire, except when extinguishing the fire may unduly jeopardize the safety of plant personnel and equipment, or may cause the fire to spread, in which case the stockpile fire may be permitted to burn itself out.

23. A watering truck and/or the coal yard watering system shall be used to minimize dust emissions from the active coal storage pile area. Surface crusting agents or like chemicals shall be used to minimize dust emissions from the inactive coal storage pile area.

24. Permanent plant roads shall be paved with a cohesive hard surface which can be cleaned by sweeping or washing. Other roads shall be sprinkled with water and/or surface crusting agents as necessary to maintain compliance with all TCEQ rules and regulations.

25. Material storage area footprints shall be limited as follows:

Source	EPN	Area
Active Coal Pile No.1	S07	27,560 ft²
Active Coal Pile No. 2	S08	27,560 ft²
Inactive coal pile	S14	600,625 ft²
Disposal area - active working face*	S26a	43,560 ft²
Disposal area - inactive exposed surfaces*	S26b	217,800 ft²

*footprint is not limited to a specific location

26. All conveyors shall be covered, enclosed, partially covered, or partially enclosed, as represented in the application, to minimize fugitive PM emissions. If visibility problems occur, additional controls may be required. Coverings and enclosures are considered abatement equipment, and should be kept in good repair.

27. Fugitive emissions from the transfer points on belt conveyors, any material handling, and the stockpile activities shall not create an off-property nuisance condition. A trained observer with delegation from the Executive Director of the TCEQ may determine compliance with this special condition by 40 CFR Part 60, Appendix A, TM 22, or equivalent. Continuous demonstration of compliance with this special condition is not required. If this condition is violated, additional controls or process changes may be required to limit visible PM emissions.

28. As determined by a certified opacity observer with delegation from the Executive Director of the TCEQ and according to 40 CFR 60, Appendix A, TM 9, or equivalent, opacity of emissions from any single fabric filter baghouse stack listed in Special Condition No. 29 shall not exceed 5 percent averaged over a six-minute period. Continuous demonstration of compliance with this special condition is not required.

29. Material handling baghouses, designed to meet an emission limit of 0.01 grain PM per dry standard cubic foot of exhaust, properly installed and in good working order, shall control PM emissions from the following sources:

Source	EPN
Railcar coal unloading station and substructure	S03a
Active coal pile reclaim	S09
Coal transfer tower	S11
Coal silos and tripper deck conveyor	S13
Fly ash silo	S18
Fly ash transfer point #1	S23
Railcar lime unloading	S27a
Lime silo	S29
Urea silo	S30

Initial Demonstration of Compliance

30. The holder of this permit shall perform initial stack sampling and other testing to establish the actual quantities of air contaminants being emitted into the atmosphere. Unless otherwise specified in this Special Condition No. 30, the sampling and testing shall be conducted in accordance with the methods and procedures specified in Special Condition No. 31. The holder of this permit is responsible for providing sampling and testing facilities and conducting the

sampling and testing operations at his expense. The TCEQ Executive Director or his designated representative shall be afforded the opportunity to observe all such sampling.

A. For the PC Boiler, EPN S01:

(1) Demonstrate compliance with the performance standards of Special Condition No. 10.B and the hourly emission rates of the maximum allowable emissions rate table (MAERT), applicable to normal operations, using the average of three stack sampling test runs of at least one hour per run for each contaminant.

(2) Air contaminants to be sampled and analyzed under (1) above include: NO_x, SO_2, CO, VOC, H_2SO_4, HCl, HF, PM, PM_{10}, NH_3, Hg, phosphorus, non-Hg HAP metals, and organic HAP. Diluents to be measured include O_2 or carbon dioxide (CO_2).

(3) Demonstrate compliance with the performance standards of Special Condition No. 9 applicable to normal operations, using the average of 30 six-minute readings as provided in 40 CFR 60.11(b).

(4) Demonstrate compliance with 40 CFR 60, Subparts A and Da, for NO_x, SO_2, PM, and opacity.

(5) Demonstrate compliance with the lb/MMBtu performance standards listed on Attachment A and the lb/hr emission rate for lead listed on the MAERT using the average of three stack sampling test runs.

(6) Calculate HCl, HF and SeO removal efficiencies based on the difference between the stack sampling results for these compounds and an analysis of their concentration in a sample of coal that is representative of the fuel being fired during the stack testing. Removal efficiencies are calculated as follows:

$$\eta = \frac{HAP_{Coal} - HAP_{Stack}}{HAP_{Coal}} \times 100\%$$

Where:

η = Removal efficiency, %

HAP_{Coal} = Concentration of the HAP in coal, lb/MMBtu as converted from elemental form as tested (i.e. Cl, F and Se)
HAP_{Stack} = Concentration of the HAP as determined by stack test, lb/MMBtu

(7) Boiler load during testing shall be maintained as follows.

(a) Operate at maximum firing rates for the atmospheric conditions occurring during the test as measured by millions of pounds of steam generated per hour or MW of electric generator output. If the steam generating unit is unable to operate at maximum rates during testing, then additional stack testing may be required when higher production rates are achieved.

(b) During 30-day average emission testing, the boiler load does not have to be maximum, but the load must be representative of future operating conditions and must include at least one 24-hour period at full load.

(c) Separate and additional to (a), operate at 50 percent load while testing for VOC emissions in order to demonstrate compliance with the VOC emission limits at reduced load as well as full load.

(8) During the sampling runs for HCl and HF, the permit holder shall monitor and record the rate of sorbent injection into the spray dryer absorber ("Demonstration Sorbent Injection Rate"). **(6/12)**

B. For the auxiliary boiler, EPN S02:

(1) Demonstrate compliance with the NO_x performance standard of Special Condition No. 15 and the hourly NO_x and CO emission rates of the MAERT, using the average of three one-hour stack sampling test runs for each contaminant.

(2) Demonstrate compliance with the opacity limitation of 40 CFR 60 Subpart Db and Special Condition No. 15.

(3) Demonstrate compliance with the SO_2 emission rate of the MAERT through fuel sampling to demonstrate use of pipeline quality natural gas.

(4) Demonstrate compliance with the PM/PM_{10} and VOC emission rates of the MAERT through operation of the auxiliary boiler within its design limitations.

C. (1) For the coal handling facilities with stack emissions, EPNs S03a, S09, S11, and S13, demonstrate compliance with the opacity limits of this permit and 40 CFR 60, Subpart Y.

(2) For the coal handling facilities with fugitive emissions, EPNs S03b, S05, S06, S10, and S12, demonstrate compliance with the opacity limits of 40 CFR 60, Subpart Y using 40 CFR Part 60, Appendix A, Test Method 22.

D. For at least one material handling baghouse, to be selected by the Waco Regional Director of the TCEQ, or his designated representative, sample PM emissions using TM 5 testing to show compliance with the emission limit of Special Condition No. 29.

E. For the emergency generator and fire-water pump, EPNs S33 and S34, demonstrate compliance with the emission rates of the MAERT by showing compliance with the requirements of Special Condition No. 16 and 17, respectively.

F. For the cooling tower, EPN S32, demonstrate compliance with the emission rates of the MAERT by records that demonstrate that the drift eliminators are designed to limit drift as specified in the application, and by inspection of modules, selected by the regional director or his designated representative, for: consistency with the specified design; flow bypassing the drift eliminators; and damage to the eliminators.

G. Requests to waive testing for any pollutant specified in this condition shall be submitted to the TCEQ Waco Regional Office and the TCEQ Austin Office of Air, Air Permits Division. Test waivers and alternate or equivalent procedure proposals for New Source Performance Standards testing which must have EPA approval shall be submitted to the TCEQ Waco Regional Office.

H. Sampling as required by this condition shall occur within 60 days after achieving the maximum fuel firing rate at which the PC Boiler will be operated but no later than 180 days after initial start-up. The first boiler operating day of 30-day average initial performance testing required by 40 CFR 60.46a(f) must commence within this time.

Test Methods and Procedures

31. A. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual; EPA Methods in 40 CFR Part 60,

Appendix A; 40 CFR Part 63, Appendix A; 40 CFR Part 51, Appendix M; EPA Other Test Methods; EPA Conditional Test Methods; EPA SW 846 "Test Methods for Evaluating Solid Waste, Physical/Chemical Methods"; and American Society for Testing and Materials (ASTM) as follows:

(1) Appendix A, Methods 1 through 4, as appropriate, for exhaust flow, diluent, and moisture concentration;

(2) Appendix A, Method 5 or 17, modified to include back-half condensibles, for the concentration of PM;

(3) Appendix A, Method 5 or 17, for the filterable concentration of PM (front-half catch);

(4) Appendix A, Method 6, 6a, 6c, or 8, for the concentration of SO_2;

(5) Appendix A, Method 7E for the concentrations of NO_x and O_2, or equivalent methods;

(6) Appendix A, Method 8 or a modified Method 8 for H_2SO_4;

(7) Appendix A, Method 9 for opacity;

(8) Appendix A, Method 10 for the concentration of CO;

(9) Appendix A, Method 18 for acrolein and methyl chloride;

(10) Appendix A, Method 19, for applicable calculation methods;

(11) Appendix A, Method 23 for dioxin/furan;

(12) Appendix A, Method 25A, modified to exclude methane and ethane, for the concentration of VOC (to measure total carbon as propane);

(13) Appendix A, Method 26 or 26A for HCl and HF;

(14) EPA Conditional Test Method 27 (CTM-027), for NH_3;

(15) Appendix A, Method 29 for the metals listed in Attachment A and phosphorous;

(16) Appendix M, Methods 201A and 202, or Appendix A, Test Method 5, modified to include back-half condensibles, for the concentration of particulate matter less than 10 microns in diameter, PM_{10};

(17) Appendix M, Methods 201A or Appendix A, Test Method 5, for the filterable concentration of particulate matter less than 10 microns in diameter, PM_{10} (front-half catch);

(18) ASTM D6784-02, Standard Test Method for Elemental, Oxidized, Particle-Bound, and Total Mercury in Flue Gas Generated from Coal-

Fired Stationary Sources (also known as the Ontario Hydro Method), or other approved EPA methods for measuring mercury;

(19) EPA SW 846, Method 0031 with analytical method 8260B for volatile organic HAP, Method 0010 with analytical method 8270D for semi-volatile organic HAP, and Method 0011 with analytical method 8315A for formaldehyde, acetaldehyde, and other select aldehydes, and ketones;

(20) EPA 40 CFR 63, Appendix A, Method 320 is an acceptable alternative for aldehydes;

(21) EPA Other Test Method 029 (OTM-029) for hydrogen cyanide;

(22) Any deviations from those procedures must be approved by the Executive Director of the TCEQ prior to sampling.

B. The TCEQ Waco Regional Office shall be given notice as soon as testing is scheduled but not less than 30 days prior to sampling to schedule a pretest meeting.

(1) The notice shall include:

(a) Date for pretest meeting.
(b) Date sampling will occur.
(c) Name of firm conducting sampling.
(d) Type of sampling equipment to be used.
(e) Method or procedure to be used in sampling.
(f) Projected date of commencement of the 30-day rolling average initial performance tests for SO_2 and NO_x, in accordance with 40 CFR 60.46a(f).

(2) The purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for submitting the test reports. The permit holder shall present at the pretest meeting the manner in which stack sampling will be executed in order to demonstrate compliance with emission standards found in this permit and 40 CFR Part 60, Subparts Da, Db, and Y.

(3) Prior to the pretest meeting, a written proposed description of any deviation from sampling procedures specified in permit conditions or TCEQ, EPA or ASTM sampling procedures shall be made available to the TCEQ. The TCEQ Regional Director shall approve or disapprove of any deviation from specified sampling procedures.

C. Information in the test report shall include the following data for each test run:

(1) hourly coal firing rate (in tons);

(2) average coal Btu/lb as-received and dry weight;

(3) average steam generation rate in millions of pounds per hour;

(4) average generator output in MW;

(5) daily sulfur content and heat content of the fuel measured in accordance with EPA TM 19 to show compliance with 40 CFR 60, Subpart Da;

(6) control device operating rates, including SCR reagent injection rate, the Demonstration Sorbent Injection Rate, as defined in Special Condition No. 30, and if applicable, the lime/ash reinjection rate; **(6/12)**

(7) emissions in the units of the limits of this permit, lb/hr and lb/MMBtu, three-hour or 30-day average, as appropriate.

(8) any additional records deemed necessary during the stack sampling pre-test meeting.

D. Two copies of the final sampling report shall be forwarded to the TCEQ within 60 days after sampling is completed. Sampling reports shall comply with the attached conditions of Chapter 14 of the TCEQ Sampling Procedures Manual. The reports shall be distributed as follows:

One copy to the TCEQ Waco Regional Office.
One copy to the TCEQ Austin Office of Air, Air Permits Division.

Continuous Demonstration of Compliance

32. The holder of this permit shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) to measure and record the concentrations of NO_x, CO, and SO_2 from EPN S01. Diluents to be measured include O_2 or CO_2. The CEMS data shall be used to determine continuous compliance with the NO_x, CO, and SO_2 emission limitations in Special Condition No. 3A (NO_x and SO_2), Special Condition No. 10A, and the attached MAERT. Except as provided by Special Condition No. 49, continuous compliance with the performance standards of Special Condition No. 10A shall commence on the first boiler operating day of the 30-day

initial performance testing required by NSPS Subpart Da.

A. The CEMS shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable Performance Specification Nos. 1 through 9, 40 CFR Part 60, Appendix B or an acceptable alternative. If there are no applicable performance specifications in 40 CFR Part 60, Appendix B, contact the TCEQ Austin Office of Air, Air Permits Division for requirements to be met.

B. The holder of this permit shall assure that the CEMS meets the applicable quality assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1, or an acceptable alternative. Relative accuracy exceedances, as specified in 40 CFR Part 60, Appendix F, § 5.2.3 and any CEMS downtime and all cylinder gas audit exceedances of ±15 percent accuracy shall be reported semiannually to the appropriate TCEQ Regional Director, and necessary corrective action shall be taken. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Director.

C. The monitoring data shall be reduced to hourly average concentrations at least once a day, using normally a minimum of four equally-spaced data points from each one-hour period. The individual average concentrations shall be reduced to units of the permit allowable emission rate in pounds per hour at least once a day. Pound per hour data shall be summed on a monthly basis to tons per year and used to determine compliance with the annual emissions limits of this permit. If the CEMS malfunctions, then the recorded concentrations may be reduced to units of the permit allowable as soon as practicable after the CEMS resumes normal operation.

D. The appropriate TCEQ Regional Office shall be notified at least 30 days prior to any required relative accuracy test audits in order to provide them the opportunity to observe the testing.

E. If applicable, each CEMS will be required to meet the design and performance specifications, pass the field tests, and meet the installation requirements and data analysis and reporting requirements specified in the applicable performance specifications in 40 CFR Part 75, Appendix A and B, as an acceptable alternative to paragraph A. of this condition.

F. Each CEMS shall be operational during 95% of the operating hours of the PC Boiler, exclusive of the time required for zero and span checks. If this operational criteria is not met for the reporting quarter, the holder of this permit shall develop and implement a monitor quality improvement plan. The plan should address the downtime issues to improve availability and reliability. The plan should provide additional assurance of compliance including record keeping of reagent flow rates for monitor downtime periods.

33. The holder of this permit shall install, calibrate, operate, and maintain a continuous opacity monitoring system (COMS) to measure and record the opacity of emissions from EPN S01. The COMS data shall be used to determine continuous compliance with the opacity emission limitations in Special Conditions No. 3A and 9.

   A. The COMS shall satisfy all of the Federal NSPS requirements for COMS as specified in 40 CFR Part 60, Appendix B, Performance Specification 1 (PS-1). In order to demonstrate compliance with PS-1, the COMS shall meet the manufacturer's design and performance specifications, and undergo performance evaluation testing as outlined in 40 CFR 60, Subpart A, § 60.13. The TCEQ Regional Director shall be notified 30 days prior to the certification.

   B. The COMS shall be zeroed and spanned daily as specified in 40 CFR Part § 60.13. Corrective action shall be taken when the 24-hour span drift exceeds two times the amounts specified in PS-1, or as specified by the TCEQ if not specified in PS-1.

   C. If the EPA promulgates a quality assurance, quality control standard for the COMS, a Quality Assurance Plan (QAP) shall be prepared in accordance with the EPA standard for the COMS and adhered to, within six months after promulgation. The QAP shall be maintained to reflect changes to component technology. At the request of the TCEQ Regional Director, the holder of this permit shall submit documentation demonstrating compliance with these standards.

   D. The data shall be reduced to six-minute opacity averages, using a minimum of 36 equally-spaced data points from each six-minute period.

   E. The COMS shall be operational during 95% of the operating hours of the PC Boiler, exclusive of the time required for zero and span checks. If this operational criteria is not met for the reporting quarter, the holder of this permit shall develop and implement a monitor quality improvement plan. The plan should address the downtime issues to improve availability and reliability. The plan should provide additional assurance of compliance including EPA Test Method 9 support during daytime monitor downtime periods and parametric support for nighttime monitor downtime periods.

F. Recertification, if required, shall be based on the requirements of 40 CFR Part 60, Appendix B, PS-1 in effect at the time of initial certification.

34. The holder of this permit shall install, calibrate, operate, and maintain a CEMS to measure and record the concentration of NH_3 from EPN S01. The NH_3 concentrations shall be corrected and reported in accordance with Special Condition No. 10A. The CEMS data shall be used to determine continuous compliance with the NH_3 performance specifications in Special Condition No. 10A and the MAERT. Any other method used for measuring NH_3 slip shall require prior approval from the TCEQ Waco Regional Office, with consultation between the Regional Office and the TCEQ Austin Air Permits Division.

35. The holder of this permit shall install, calibrate, operate, and maintain a CEMS or sorbent trap monitoring system to measure and record the concentration of mercury from EPN S01, as described in 40 CFR Part 63. The continuous monitoring system data shall be used to demonstrate continuous compliance with the emission limitations of Special Condition No. 10A and the MAERT.

36. If any emission monitor fails to meet specified performance, it shall be repaired or replaced as soon as reasonably possible.

37. The holder of this permit shall use the following procedures and equations to calculate the monthly plant-wide emissions of each single HAP and the combined total HAP from the SCES. The monthly emissions of each single HAP and the combined HAP shall be summed each month to tons per year and used to determine compliance with the annual HAP emission limits of Special Condition No. 11 and the MAERT.

A. Calculation of monthly HCl emissions from the PC-fired boiler:

$$\mathbf{HCl} = \frac{1\ ton}{2000\ lb}\sum_{i=1}^{n}(\mathbf{EF}_{\mathbf{HCl}}) \times \mathbf{HI}_i$$

Where:

HCl = Monthly HCl emissions from the PC Boiler in tons per month.

HI_i = Heat input in MMBtu/hr for the i^{th} operating hour in the month as calculated from the Part 75-certified CEMS.

n = Number of operating hours in the month.

EF_{HCl} = $(CC/GCV)(1\text{-}HCl_R)(HCl/Cl)$

CC = Monthly average chlorine content as computed from data obtained pursuant to Special Condition No. 38.

GCV = Monthly average gross calorific value as computed from data obtained pursuant to Special Condition No. 38.

HCl_R = Percent removal of HCl, as used in the calculation of EF_{HCl}, determined from the most recent stack testing results in Special Condition Nos. 30.A. and 39, approved by the TCEQ Waco Regional Office. **(6/12)**

HCl/Cl = HCl-to-Cl conversion factor = 36.5/35.5.

B. Calculation of monthly HF emissions from the PC-fired boiler:

$$HF = \frac{1\ ton}{2000\ lb}\sum_{i=1}^{n}(EF_{HF}) \times HI_i$$

Where:

HF = Monthly HF emissions from the PC-fired boiler in tons per month.

HI_i = Heat input in MMBtu/hr for the i^{th} operating hour in the month as calculated from the Part 75-certified CEMS.

n = Number of operating hours in the month.

EF_{HF} = $(FC/GCV)(1\text{-}HF_R)(HF/F)$

FC = Monthly average fluorine content as computed from data obtained pursuant to Special Condition No. 38.

GCV = Monthly average gross calorific value as computed from data obtained pursuant to Special Condition No. 38.

HF_R = Percent removal of HF, as used in the calculation of EF_{HF}, determined from the most recent stack testing results in Special Condition Nos. 30.A. and 39, approved by the TCEQ Waco Regional Office. **(6/12)**

HF/F = HF-to-F conversion factor = 20.0/19.0.

C. Calculation of monthly emissions of non-mercury metal compounds (other than selenium compounds) that are included in Section 112 of the Clean Air Act from the PC-fired boiler:

$$\text{Metal compound}_j = \frac{1\ ton}{2000\ lb}\sum_{i=1}^{n}(EFMC)_j \times \frac{HI_i}{10^6}$$

Where:

Metal compound$_j$ = Monthly emissions of the j[th] metal compound (excluding mercury and selenium), assuming the compound is the lowest oxidized species of the elemental metal (antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, and nickel), from the PC-fired boiler in tons per month.

HI_i = Heat input in MMBtu/hr for the i[th] operating hour in the month as calculated from the Part 75-certified CEMS.

n = Number of operating hours in the month.

$EFMC_j$ = Emission Factor of the j[th] metal compound in pounds of pollutant per trillion Btu heat input (lb/TBtu), derived utilizing the following equations:

Metal Compound	$MW_{Compound}$	$MW_{Element}$	Equation
Antimony trioxide (Sb_2O_3)	291.50	121.75	$(1.10)\ X^{0.63}$
Arsenic trioxide (As_2O_3)	197.84	74.92	$(4.09)\ X^{0.85}$
Beryllium oxide (BeO)	25.01	9.01	$(3.33)\ X^{1.1}$
Cadmium oxide (CdO)	128.41	112.41	$(3.77)\ X^{0.50}$
Chromium oxide (CrO)	68.00	52.00	$(4.84)\ X^{0.58}$
Cobalt oxide (CoO)	74.93	58.93	$(2.16)\ X^{0.69}$

Metal Compound	$MW_{Compound}$	$MW_{Element}$	Equation
Lead oxide (PbO)	223.19	207.19	$(3.66)\ X^{0.80}$
Manganese dioxide (MnO_2)	70.94	54.94	$(4.91)\ X^{0.60}$
Nickel oxide (NiO)	74.70	58.70	$(5.60)\ X^{0.48}$

Where $X = (MC_j/AC * PM)$

and

MC_j = Monthly average of the j[th] metal content as computed from data obtained pursuant to Special Condition No. 38, expressed in parts per million.

AC = Monthly average of the ash content of the coal as computed from data obtained pursuant to Special Condition No. 38.
PM = Maximum filterable particulate matter concentration, 0.015 lb/MMBtu.

D. Calculation of monthly emissions of selenium dioxide (SeO_2) from the PC-fired boiler:

$$SeO_2 = \frac{1\ ton}{2000\ lb} \sum_{i=1}^{n} (EF_{SeO2}) \times HI_i$$

Where:

SeO_2 = Monthly SeO_2 emissions from the PC-fired boiler in tons per month.

HI_i = Heat input in MMBtu/hr for the i[th] operating hour in the month as calculated from the Part 75-certified CEMS.

n = Number of operating hours in the month.
EF_{SeO2} = $(SeC/GCV)(1\text{-}SeO_{2R})(SeO_2/Se)$

SeC = Monthly average selenium content as computed from data obtained pursuant to Special Condition No. 38.

GCV = Monthly average gross calorific value as computed from data obtained pursuant to Special Condition No. 38.

SeO_{2R} = Percent removal of SeO_2 from stack testing results in Special Condition Nos. 30.A. and 39, approved by the TCEQ Waco Regional Office.

SeO_2/O = SeO_2-to-Se conversion factor = 110.96/78.96.

E. Calculation of monthly emissions of all other substances that are listed in Section 112 of the Clean Air Act from the PC-fired boiler:

$$HAP_j = \frac{1\ ton}{2000 lb} \sum_{i=1}^{n} (EF)_j \times HI_i$$

Where,

HAP_j = Monthly emissions of the j^{th} HAP of all other substances included in section 112 of the Clean Air Act from the PC-fired boiler in tons per month.

HI_i = Heat input in MMBtu/hr for the i^{th} operating hour in the month as calculated from the Part 75-certified CEMS.

n = Number of operating hours in the month.

EF = Test-generated emission factor in lbs/MMBtu from stack testing results in Special Condition Nos. 30.A.(2) and 39, and approved by the TCEQ Waco Regional Office.

F. Calculation of monthly emissions of all HAPs that are listed in Section 112 of the Clean Air Act from the other combustion sources (the auxiliary boiler, emergency generator, and emergency fire water pump) at the SCES:

$$OC_j = (EF)_j \times HI$$

Where,

OC_j = Monthly emissions of the j^{th} HAP of all HAPs listed in section 112 of the Clean Air Act from the auxiliary boiler and emergency engines, in tons per month.

EF = Emission Factor in lbs/MMBtu from HAP emission factors for the auxiliary boiler and emergency engines listed in the updated permit alteration representations dated April 20, 2011.

HI = Total heat input in MMBtu for the month for the combustion source.

G. Monthly mercury emissions using data acquired by the Mercury CEMS.

H. Individual and combined HAP emissions are assumed to be:

(1) from all coal and ash handling emissions, 0.006 ton per year of metallic HAP; and

(2) from all fuel storage tanks, 0.002 ton per year of organic HAP.

I. Total HAPs emitted each month shall be calculated by adding the individual HAP emissions from Special Condition No. 37 (A)-(G).

38. The holder of this permit shall obtain a representative sample of the coal as-fired on a weekly basis for analysis for sulfur content (%S), moisture content, ash content, chlorine content, fluorine content, antimony content, arsenic content, beryllium content, cadmium content, chromium content, cobalt content, lead content, manganese content, nickel content, selenium content, and gross calorific value (GCV). The sample shall be acquired and analyzed using the procedures of 40 CFR Part 60, Appendix A, Test Method 19, § 5.2.1. The sample data shall be used after the initial demonstration of compliance to:

A. determine ongoing compliance with the non-mercury metal performance standards identified in Attachment A of this permit, the emission rates for lead in the MAERT, and the sulfur content of Special Condition No. 7; and

B. calculate the on-going HAP emissions in accordance with the calculation procedures of Special Condition No. 37.

39. After the initial demonstration of compliance, ongoing stack sampling of EPN S01 for H_2SO_4, HCl, HF, HCN, phosphorus, VOC, volatile organic HAP, semi-volatile organic HAP, dioxins, non-mercury HAP metals, and total PM/PM_{10} emissions shall be used to demonstrate ongoing compliance and shall meet the following specifications:

A. Stack sampling shall be performed once annually during periods of normal operation, except as follows: **(6/12)**

(1) If the test does not establish compliance with a performance standard of

Special Condition No. 10B, the holder of this permit may conduct additional tests during the year to be averaged with the previous test(s) to demonstrate compliance.

(2) If, after two years of stack sampling, the average of the stack sampling results for a pollutant is less than 70% of the applicable performance standard identified in Special Condition No. 10B, then compliance stack sampling for such pollutant may be conducted once every three years.

(3) For HCl, HF, and organic HAPs:

(a) stack testing must occur at six-month intervals for the two-year period starting with the initial performance test required by Special Condition No. 30; and

(b) for three years thereafter, if the most recent performance test required or allowed by this Special Condition measures emissions above 90% of the performance standard identified in Special Condition No. 10B, another performance test for that constituent shall be conducted within six months.

B. Sampling required in (A.) of this Special Condition shall demonstrate compliance with the performance standards of Special Condition No. 10B and the lb/hr emission limits of the MAERT applicable to normal operations.

C. Sampling required in (A.) of this Special Condition shall be conducted in accordance with the methods, procedures, and notification protocol specified in Special Condition No. 31.

D. Ongoing compliance with the H_2SO_4 tons per year emission rates in the MAERT shall be demonstrated by calculating rolling 12-month annual emissions from emission factors (lb/MMBtu, HHV) obtained from the sampling required in (A.) of this condition and the monthly total heat input (MMBtu, HHV) from coal.

40. Compliance with the following emission rates in the MAERT, applicable to periods of startup and shutdown, will be demonstrated as follows:

A. Compliance with the lead and PM and PM_{10} (filterable and total) emission rates in the MAERT applicable during startup and shutdown will be demonstrated if the recorded pressure drop across the baghouse meet manufacturer guidelines for proper operation during startup and shutdown.

B. Compliance with the VOC emission rate in the MAERT applicable during startup and shutdown will be demonstrated if the CO emissions during startup and shutdown are in compliance with the CO emission rate in the MAERT for startup and shutdown.

C. Compliance with the H_2SO_4, HF, and HCl emission rates in the MAERT for startup and shutdown will be demonstrated if the SO_2 emissions during startup and shutdown are in compliance with the SO_2 emission rate in the MAERT for startup and shutdown.

41. Following the initial demonstration of compliance, ongoing compliance with the emission limits for the sources and emission limitations listed in this condition shall be through source operation in accordance with manufacturer's specifications, or in accordance with written procedures that are shown to maintain operating conditions necessary for emission compliance. The Executive Director of the TCEQ or his designated representative may also require direct measurement of emissions using the sampling methods and procedures specified in Special Condition No. 31 to establish compliance with the limitations, in which case the sampled emission rate will be used to determine compliance.

    A. The auxiliary boiler, EPN S02, emission limitations of Special Condition No. 15A and 15B and the MAERT.

    B. The emergency diesel engines, EPNs S33 and S34, emission limitations in the MAERT.

42. Following the initial demonstration of compliance, ongoing compliance with the emission rates in the MAERT for the cooling tower, EPN S32, will be based on annual inspection of modules, and repair as necessary to maintain drift eliminator structural integrity and minimize bypassing of flow around drift eliminators.

43. Following the initial demonstration of compliance, ongoing compliance with the emission rates in the MAERT for the coal, ash, lime and urea material handling baghouses will be demonstrated by annual opacity testing using TM 9 for EPNs S03a, S09, S11, and S13 and TM 22 for EPNs S18, S23, S27a, S29, and S30. The Executive Director of the TCEQ or his designated representative may also require sampling conducted in accordance with the methods and procedures specified in Special Condition No. 31 to directly measure the lb/hr emission rate, in which case the sampled lb/hr emission rate will be used to determine compliance with the applicable emission rate in the MAERT.

44. Compliance with the emission rates in the MAERT for the fuel storage tanks, EPN

S36 through S38, will be demonstrated by compliance with Special Condition No. 20.

Recordkeeping Requirements

45. The following records shall be kept at the plant for the life of the permit. All records required in this permit shall be made available at the request of personnel from the TCEQ, the EPA, or any air pollution control agency with jurisdiction.

    A. A copy of this permit.

    B. A copy of the permit application dated January 9, 2004 and all subsequent updates submitted to the TCEQ. **(6/12)**

    C. A complete copy of the testing reports and records of the initial air emissions performance testing completed pursuant to the Initial Demonstration of Compliance.

    D. Required stack sampling results or other air emissions testing (other than CEMS or COMS data) that may be conducted on units authorized under this permit after the date of issuance of this permit.

46. The following records shall be kept for a minimum of five years after collection and shall be made immediately available upon request to representatives of the TCEQ, the EPA, or any local air pollution control program having jurisdiction. Records shall be legible and maintained in an orderly manner. The following records shall be maintained:

    A. Continuous emission monitoring data for opacity, SO_2, NO_x, CO, and diluent gases, O_2 or CO_2, from CEMS to demonstrate compliance with the emission rates listed in the MAERT and performance standards listed in this permit for pollutants that are monitored by CEMS or COMS. Data retention at intervals less than one hour is not required. Records should identify the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, maintenance, and malfunction along with the justification for excluding data. Records should also identify factors used in calculations that are used to demonstrate compliance with emissions limits and performance standards.

    B. Files of all CEMS or COMS quality assurance measures, calibration checks, adjustments and maintenance performed on these systems.

C. Steam turbine generator hourly gross electrical output in MW, including identification of shutdown intervals, for compliance with output based performance specifications of this permit.

D. Written coal analysis for all coal received from each coal supplier to show compliance with the sulfur and trace metal concentration limits of this permit, and written analysis provided by natural gas and diesel fuel suppliers to show compliance with the sulfur content limitations of this permit.

E. Average coal feed rate to the PC Boiler in pounds per hour and the corresponding average heat input (HHV) in MMBtu/hr, based upon an average over each calendar month.

F. Monthly and rolling 12-month emissions of plant-wide HAP, including all calculations made to comply with Special Condition Nos. 11, 37, and 38.

G. Ammonia feed rate and sorbent feed rate established during a successful initial performance test to fulfill the requirements of Special Condition No. 12.

H. Hours of operation of the emergency generator, emergency fire water pump, and auxiliary boiler to show compliance with the hourly operating limitations of this permit.

I. Tons of coal received at the site monthly to show compliance with the throughput requirements of this permit.

J. The amount of fuel received for storage in EPN S36 through S38 and the consecutive 12-month total of fuel received for each source to show compliance with the throughput requirements of this permit.

K. Records of cleaning and maintenance performed on abatement equipment, including records of replacement maintenance performed on baghouses and conveyors. A log should be kept with descriptions of the activity performed and the time period over which it was performed.

L. Records required to show compliance with 40 CFR part 60, Subparts Da, Db, and Y, including records of required reporting.

M. Records of daily road maintenance for dust control to show compliance with Special Condition No. 24.

N. Records of audio, olfactory, and visual checks for ammonia and water treatment chemicals leaks and repairs to show compliance with Special Condition No. 19.

Reporting

47. The holder of this permit shall submit to the TCEQ Waco Regional Office and the Air Enforcement Branch of EPA in Dallas quarterly reports as described in 40 CFR § 60.7. Such reports are required for each emission unit which is required to be continuously monitored pursuant to this permit.

As-Built Information

48. The holder of this permit shall submit to the TCEQ Waco Regional Office and the TCEQ Air Permits Division change pages to the permit application reflective of the final plans and engineering specifications on the PC Boiler, auxiliary boiler, emergency engines, and other sources, including their respective control equipment, no later than 30 days before initial startup of the PC Boiler. This information shall include:

   A. All TCEQ Tables in the permit application, updated with manufacturer and other specified data.

   B. Revised plot plans and equipment drawings as required to reflect the constructed facility.

   C. Manufacturer's certification of emissions for the diesel engines and if applicable, cost information to verify compliance with the emission Tier requirements of this permit.

   D. Identification of any maximum inputs of raw materials for the as-built facility, and any diesel fuel sulfur or engine manufacturer=s emission specification that is lower than the values represented in the permit application and used for calculating or establishing emissions. Accompanying this information shall be a request for permit alteration. The TCEQ shall alter the permit special conditions and MAERT to reflect any such reduction in emissions. Increases in allowable emission rates require a permit amendment before construction begins. A permit amendment or alteration is not required if the change(s) to the facility as built qualify for an exemption from permitting or permit by rule under 30 TAC Chapter 106. **(9/11)**

Optimization Studies

49. If the permit holder is unable to demonstrate compliance with the PC Boiler performance standards identified in Special Condition No. 10A for the control of NH_3, NO_x or Hg within 180 days of initial startup, then the permit holder may request additional time for an emissions optimization study to mitigate emissions from the unit. Optimization studies may be requested by the permit holder to evaluate and implement additional efforts to mitigate the emissions of NH_3, NO_x or Hg. Exceedances of an NH_3, NO_x, or Hg emission limit that occur before or during an approved optimization study are not a violation of the emission limit or performance standard set forth for those contaminants in this permit as long as the owner or operator maintains and operates the equipment and control equipment at all times in a manner consistent with good practice for minimizing emissions. The following conditions shall be met for the studies:

   A. Prior to the initiation of optimization studies, a protocol shall be developed and approved by the Executive Director of the TCEQ. The protocol shall include at a minimum a proposed duration of the study period and an explanation of control efforts that will be evaluated. Additionally, the protocol will include a description of the specific testing that will be used to evaluate emissions during the optimization study. All stack testing done for this optimization study shall be coordinated with the TCEQ Waco Regional Office.

   B. A report summarizing the results of the optimization study shall be submitted to the TCEQ Air Permits Division and TCEQ Waco Regional Office within forty-five (45) days after the completion of the individual optimization study. This report shall include a summary of the effort utilized to mitigate emissions and the resulting emission rates measured during the study, as well as a listing of actions that will be undertaken by the permit holder to achieve the performance standard listed in Special Condition No. 10.

   C. All optimization studies shall be completed within 12 months of the initial demonstration of compliance stack testing.

50. Within 60 days after completing the first annual compliance sampling required by Special Condition 39, the holder of this permit shall submit a request to adjust the performance standards for the control of H_2SO_4, HCl, HF, and total PM/PM_{10} identified in Special Condition No. 10B to reflect the results of the sampling of these compounds conducted to that date, with appropriate consideration given for data variability. The adjustment on a pollutant-by-pollutant basis to the performance standard for the control of H_2SO_4, HCl, HF, or back-half PM/PM_{10} shall only be required if the average of the sampling for any such pollutant is 50% or less of the

currently permitted value. At a minimum, this submittal shall include the Initial Demonstration of Compliance sampling required by this permit and the first annual compliance sampling required by Special Condition No. 39.

51. The permit holder shall monitor and record the rate of sorbent injection into the spray dryer absorber during all normal coal-fired operations of the pulverized coal boiler (EPN S01) ("Operating Sorbent Rate"). If the Operating Sorbent Rate experiences abnormal variations from the Demonstration Sorbent Injection Rate, as defined in Special Condition No. 30.A.(8), then the permit holder shall take prompt and appropriate corrective action consistent with good air pollution control practices, and shall include a summary of any abnormal variations and corrective actions taken in the report required by Special Condition No. 47. **(6/12)**

Date: November 21, 2014

Attachment A
Non-mercury Metal Concentrations in Coal and Emission Performance Standards

Constituent	Annual Average Concentration (ppmw)	Performance Standard (lb/MMBtu)
Beryllium	1.7	5.0 (10^{-7})
Lead	9.48	6.7 (10^{-6})
Arsenic	25	1.0 (10^{-5})
Cadmium	0.27	9.0 (10^{-7})
Vanadium	33	2.1 (10^{-4})
Nickel	12	7.0 (10^{-6})
Silver	0.20	1.2 (10^{-6})
Barium	660	3.0 (10^{-3})
Chromium	11	7.0 (10^{-6})
Copper	20	8.8 (10^{-5})
Manganese	110	3.0 10^{-5})
Antimony	1.18	4.0 (10^{-7})
Selenium	1.68	7.0 (10^{-6})
Zinc	35	1.7 (10^{-4})
Cobalt	4	2.0 (10^{-6})

Date: June 22, 2012

Emission Sources - Maximum Allowable Emission Rates

Permit Numbers 70861 and PSDTX1039

This table lists the maximum allowable emission rates and all sources of air contaminants on the applicant's property covered by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities covered by this permit.

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
S01	Pulverized Coal (PC) Boiler (8,185 MMBtu/hr)	NO_x (30-day)	573	1,793
		NO_x (1-hr)	1,637	--
		SO_2 (30-day)	982	3,585
		SO_2 (1-hr)	2,456	--
		PM/PM_{10} (filterable)	123	538
		PM/PM_{10} (total)	246	1,076
		CO (30-day)	1,228	5,378
		CO (1-hr)	2,456	--
		VOC	29	129
		Organic HAP	--	8.5
		Sulfuric acid mist	127	133
		Hydrogen fluoride	2.0	8.6
		Hydrogen chloride	2.2	9.7
		Total Halogenated Acids (5)	--	10.7
		Ammonia	41	55
		Lead	0.55	0.41
		Mercury	0.94	0.038

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
S01	Startup Emissions - PC Boiler	NO_x	964	--
		SO_2	2,892	--
		PM/PM_{10} (filterable)	123	--
		PM/PM_{10} (total)	327	--
		CO	1,228	--
		VOC	43	--
		Sulfuric acid mist	111	--
		Hydrogen fluoride	6	--
		Hydrogen chloride	3	--
		Ammonia	41	
		Lead	0.55	--
		Mercury	0.90	--
The following source is incorporated by reference. It remains authorized by the Air Quality Standard Permit for Boilers, effective November 3, 2006. The authorization was reviewed under Registration No. 95851, issued June 9, 2011.				
S02	Natural Gas-fired Auxiliary Boiler (278 MMBtu/hr) Before Commercial Operation of Main Boiler (unlimited annual hours of operation)	NO_x	2.78	12.2
		SO_2	0.17	0.7
		CO	10.3	45.2
		$PM/PM_{10}/PM_{2.5}$	1.61	7.1
		VOC	1.8	7.9
S02	Natural Gas-fired Auxiliary Boiler (278 MMBtu/hr) After Commercial Operation of Main Boiler (operation limited to 500 hours per year)	NO_x	2.78	0.70
		SO_2	0.17	0.04
		CO	10.3	2.58
		$PM/PM_{10}/PM_{2.5}$	1.61	0.40
		VOC	1.8	0.45

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
S03a	Railcar Coal Unloading - Baghouse Vent	PM	0.28	0.15
		PM_{10}	0.13	0.072
S03b	Railcar Coal Unloading - Coal Dust Fugitives (6)	PM	0.28	0.15
		PM_{10}	0.13	0.072
S05	Stackout Conveyor #1 - Coal Dust Fugitives (6)	PM	0.25	0.15
		PM_{10}	0.12	0.070
S06	Stackout Conveyor #2 - Coal Dust Fugitives (6)	PM	0.13	0.074
		PM_{10}	0.059	0.035
S07	Active Coal Pile #1 - Coal Dust Fugitives (6)	PM	0.08	0.36
		PM_{10}	0.041	0.18
S08	Active Coal Pile #2 - Coal Dust Fugitives (6)	PM	0.08	0.36
		PM_{10}	0.041	0.18
S09	Active Coal Pile Reclaim - Baghouse Vent	PM	0.002	0.005
		PM_{10}	<0.001	0.002
S10	Reclaim Conveyor #1 - Coal Dust Fugitives (6)	PM	0.053	0.104
		PM_{10}	0.025	0.049
The following two sources are incorporated by reference. They remain authorized by Permit by Rule, 30 TAC § 106.262, effective November 1, 2003. The authorization was reviewed under Registration No. 97212, issued September 26, 2011.				
S10EC	Emergency Reclaim Conveyor Coal Dust Fugitives (6)	PM	0.063	0.12
		PM_{10}	0.030	0.059
S10EC	Emergency Reclaim Hopper Coal Dust Fugitives (6)	PM	0.038	0.074
		PM_{10}	0.018	0.035

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
S11	Coal Transfer Tower - Baghouse Vent	PM	0.083	0.049
		PM_{10}	0.039	0.023
The following source is incorporated by reference. It remains authorized by Permit by Rule, 30 TAC § 106.262, effective November 1, 2003. The authorization was reviewed under Registration No. 97212, issued September 26, 2011.				
S12	Reclaim Conveyor #2 - Coal Dust Fugitives (6)	PM	0.35	0.35
		PM_{10}	0.17	0.16
S13	Tripper Deck Silo Bay - Enclosed Conveyor - Baghouse Vent	PM	0.0015	0.0015
		PM_{10}	<0.001	<0.001
S14	Inactive Coal Pile - Coal Dust Fugitives (6)	PM	0.26	1.12
		PM_{10}	0.13	0.56
S15	Bottom Ash Conveyor & Drop to Bunker - Dust Fugitives (6)	PM	0.0014	0.0014
		PM_{10}	0.00064	0.00068
S16	Bottom Ash Bunker - Truck Loadout - Dust Fugitives (6)	PM	0.041	0.0057
		PM_{10}	0.019	0.0027
S18	Fly Ash Silo - Conveyor Loading - Baghouse Vent	PM	0.31	0.39
		PM_{10}	0.11	0.14
S24	Fly Ash Transfer Point #2 - Dust Fugitives (6)	PM	0.044	0.027
		PM_{10}	0.021	0.013
S26	Fly Ash Landfill - Dust Fugitives (6)	PM	0.31	1.36
		PM_{10}	0.16	0.68

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
S29	Pebble Lime Silo 1-Pneumatic Loading - Baghouse Vent	PM	0.090	0.0015
		PM_{10}	0.043	0.0007
The following two sources are incorporated by reference. They remain authorized by Permit by Rule, 30 TAC § 106.144, effective September 4, 2000. The authorization was reviewed under Registration No. 97212, issued September 26, 2011.				
S31	Pebble Lime Silo 2 Loading - Baghouse Vent	PM	0.002	<0.001
		PM_{10}	<0.001	<0.001
S35	Hydrated Lime Silo 3 Loading - Baghouse Vent	PM	<0.001	<0.001
		PM_{10}	<0.001	<0.001
S32	Cooling Tower	PM_{10}	11	50
S33	Diesel-fired Engine - Emergency Generator (1,500 kW)	NO_x	25.7	1.29
		SO_2	0.53	0.027
		CO	2.53	0.13
		$PM/PM_{10}/PM_{2.5}$	0.22	0.011
		VOC	0.53	0.027
S34	Diesel-fired Emergency Fire Water Pump (403 hp)	NO_x	3.41	0.17
		SO_2	0.11	0.0053
		CO	0.66	0.033
		$PM/PM_{10}/PM_{2.5}$	0.081	0.0040
		VOC	0.14	0.0071
S37	Diesel Fuel Storage Tank (800 gallons)	VOC	0.023	<0.001
S38	Diesel Fuel Storage Tank (580 gallons)	VOC	0.056	<0.001

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
S39	Aqueous Ammonia Fugitives (6)	Ammonia	0.16	0.70
The following sources are incorporated by reference. They remain authorized by Permit by Rule, as indicated after each source name. The authorizations were reviewed under Registration No. 97212, issued September 26, 2011.				
S40	Fire Water Booster Pump Engine (109 hp) [30 TAC § 106.511]	NO_x	1.36	0.068
		CO	0.32	0.016
		VOC	0.038	0.0019
		SO_2	0.029	0.0014
		$PM/PM_{10}/PM_{2.5}$	0.072	0.0036
S41	Diesel Fuel Storage Tank (290 gallons) [30 TAC § 106.473]	VOC	0.039	<0.001
S42	Activated Carbon Silo - Baghouse Vent [30 TAC § 106.144]	$PM/PM_{10}/PM_{2.5}$	<0.001	<0.001
S44	Soda Ash Silo - Baghouse Vent [30 TAC § 106.144]	$PM/PM_{10}/PM_{2.5}$	<0.001	<0.001
S58	Recycled Ash Silo - Baghouse Vent [30 TAC §§ 106.261-106.262]	PM	0.26	1.11
		PM_{10}	0.09	0.39
S59	Lube Oil Mist Eliminator Vent [30 TAC § 106.261]	VOC	0.091	0.40
S60	Lube Oil Tank [30 TAC § 106.472]	VOC	0.010	<0.001
S61	Sulfuric Acid Tank - Condensate Polishing [30 TAC § 106.472]	Sulfuric acid	<0.001	<0.001
S62	Sodium Hypochlorite Tank - Cooling Water Treatment [30 TAC § 106.472]	Sodium Hypochlorite	1.24	0.078
S63	Sodium Bromide Tank - Cooling Water Treatment [30 TAC § 106.472]	Sodium Bromide	0.007	<0.001

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
S64	Caustic Tank - Condensate Polishing [30 TAC § 106.472]	Caustic	<0.001	<0.001
S65	Sulfuric Acid Tank - Cooling Water Treatment [30 TAC § 106.472]	Sulfuric Acid	<0.001	<0.001
S66	Sulfuric Acid Tank - Process Water Treatment [30 TAC § 106.472]	Sulfuric Acid	<0.001	<0.001
S67	Sodium Hypochlorite Tank - Process Water Treatment [30 TAC § 106.472]	Sodium Hypochlorite	1.24	0.078
S68	Ferric Chloride Tank - Process Water Treatment [30 TAC § 106.472]	Ferric Chloride	0.25	0.010
S69	Caustic Tank - Process Water Treatment [30 TAC § 106.472]	Caustic	0.088	0.005
S71	Hydraulic Fluid Tank [30 TAC § 106.472]	VOC	<0.001	<0.001
S72	Diesel Fuel Storage Tank (5,000 gallons) [30 TAC § 106.472]	VOC	0.08	0.0032
S73	Diesel Fuel Storage Tank (5,000 gallons) [30 TAC § 106.472]	VOC	0.08	0.0032
S74AB	Recycled Ash Wetting/Mixing Drop from silo to mix tank (6) [30 TAC §§ 106.261-106.262]	PM	0.006	0.024
		PM_{10}	0.003	0.011

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) NO_x - total oxides of nitrogen
SO_2 - sulfur dioxide
PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$
PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$
CO - carbon monoxide
VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
HAP - hazardous air pollutants

Emission Sources - Maximum Allowable Emission Rates

(4) Compliance with annual emission limits (tons per year) is based on a 12-month rolling period. Annual limits include emissions from normal and planned maintenance, startup, and shutdown emissions.
(5) Total halogenated acids equals the sum of hydrogen chloride and hydrogen fluoride emissions. Although separate annual emission limits are established for HCl and HF, total annual emissions of these air pollutants shall not exceed the single annual emission limit for total halogenated acids.
(6) Fugitive emission rate is an estimate and is enforceable through compliance with the applicable special conditions and permit application representations.

Date: November 21, 2014

Summary Operations Report

Start Date: 01/01/2012 00:00

Stop Date: 12/31/2012 23:59

Total Hours Operated: 587

Total Hours Gas Firing: 587

Total Hours Coal Firing: 270

STANDARD LABORATORIES, INC.
1530 N. Cullen Avenue, Evansville, IN 47715

FOR:

SANDY CREEK SERICES, LLC
c/o SANDY CREEK ENERGY STATION
RIESEL, TX 73382
ATTN: BRYON KOHLS

ID:

As Fired Samples
Weekly Composite
December 9-15

LAB NO.: 2012-1491-12
DATE RECEIVED: 12/18/12

DATE REPORTED: 01/18/13

PROXIMATE ANALYSIS

	% As Received	Dry Basis
Moisture	27.86	
Ash	6.77	9.38
Volatile	30.85	42.77
Fixed Carbon	34.52	47.85
Sulfur	0.34	0.47
Btu/lb	8509	11795
MAF Btu/lb		13016

MINERAL ANALYSIS OF ASH

	% Ignited Basis
Silicon Dioxide	44.36
Aluminum Oxide	16.30
Titanium Dioxide	0.96
Calcium Oxide	15.92
Potassium Oxide	0.94
Magnesium Oxide	3.30
Sodium Oxide	1.04
Phosphorus Pentoxide	0.63
Ferric Oxide	6.62
Sulfur Trioxide	6.91
Barium Oxide	0.37
Manganese Dioxide	0.03
Strontium Oxide	0.20
Undetermined	2.42
Base/Acid Ratio:	0.45
Slag Viscosity T250:	2350
Fouling Index:	0.47
Slagging Index:	0.21
Silica Value:	63.19
% Alkali as Na2O:	0.16

TRACE ELEMENT

	ug/g Dry Coal Basis
Antimony	0.29
Arsenic	1.9
Barium	342
Beryllium	0.5
Cadmium	0.09
Chlorine	72
Chromium	11
Cobalt	2.4
Copper	12
Fluorine	76
Lead	2.8
Manganese	23
Mercury	0.179
Nickel	10
Selenium	0.9
Silver	0.04
Vanadium	20
Zinc	13

Respectfully Submitted, Judith Snider

FORM NO 20

STANDARD LABORATORIES, INC.

1530 N. Cullen Avenue, Evansville, IN 47715

FOR:

SANDY CREEK SERICES, LLC
c/o SANDY CREEK ENERGY STATION
RIESEL, TX 73382
ATTN: BRYON KOHLS

ID:

As Fired Samples
Weekly Composite
December 16-20

LAB NO.: 2012-1491-15
DATE RECEIVED: 01/02/13

DATE REPORTED: 01/18/13

PROXIMATE ANALYSIS

	% As Received	Dry Basis
Moisture	28.09	
Ash	5.89	8.19
Volatile	30.37	42.24
Fixed Carbon	35.65	49.57
Sulfur	0.28	0.39
Btu/lb	8574	11923
MAF Btu/lb		12987

MINERAL ANALYSIS OF ASH

	% Ignited Basis
Silicon Dioxide	36.64
Aluminum Oxide	17.88
Titanium Dioxide	1.22
Calcium Oxide	17.56
Potassium Oxide	0.60
Magnesium Oxide	3.90
Sodium Oxide	1.12
Phosphorus Pentoxide	0.84
Ferric Oxide	6.34
Sulfur Trioxide	12.66
Barium Oxide	0.47
Manganese Dioxide	0.05
Strontium Oxide	0.25
Undetermined	0.47
Base/Acid Ratio:	0.53
Slag Viscosity T250:	2280
Fouling Index:	0.59
Slagging Index:	0.21
Silica Value:	56.86
% Alkali as Na2O:	0.12

TRACE ELEMENT

	ug/g Dry Coal Basis
Antimony	0.19
Arsenic	1.4
Barium	331
Beryllium	0.3
Cadmium	0.09
Chlorine	46
Chromium	6
Cobalt	1.6
Copper	11
Fluorine	83
Lead	2.4
Manganese	17
Mercury	0.080
Nickel	5
Selenium	0.9
Silver	0.04
Vanadium	15
Zinc	11

Respectfully Submitted, Judith Snider

FORM NO 20

Sandy Creek Energy Associates, L.P.

c/o LS Power Development, LLC
Two Tower Center, 11th Floor
East Brunswick, New Jersey 08816
(732) 249-6750 Tel.
(732) 249-7290 Fax.

File No. 20.1.2.1

Via Certified Mail

April 5, 2013

Mr. Reid Harvey, Acting Director
Attn: Mr. Travis Johnson
U.S. Environmental Protection Agency
Clean Air Markets Division, MC-6204J
1200 Pennsylvania Avenue, NW
Washington, DC 20460

Re: Petition for Approval of Alternate Emissions Reporting Methodology for Unit S01 at the Sandy Creek Energy Station (ORIS Code 56611) Pursuant to 40 CFR §75.66(l)
Letter No.: SCEA-EPA-0012

Dear Mr. Harvey,

Sandy Creek Energy Associates, LP (SCEA) is submitting this petition pursuant to 40 CFR §75.4(d)(4) and 40 CFR §75.66(l) to request authorization to use alternate methodologies for calculating and reporting emissions for Unit S01 while firing natural gas in lieu of using maximum potential concentrations and stack flow rate as specified in 40 CFR §75.4(d)(1) until the facility CEMS is certified. The use of maximum potential concentrations and stack flow rate based on coal firing grossly overestimates the natural gas emissions.

<u>Background</u>

The Sandy Creek Energy Station is owned and operated in part by SCEA. The facility has a pulverized coal boiler rated at a nominal 8,185 MMBtu/hr, designated as Unit S01, which is subject to the following programs: ARP, CAIRNOX and CAIRSO2. The unit started commercial operation on October 10, 2011 but was forced to shut down during the commissioning process due to a casualty event with the boiler. The unplanned shutdown notification was submitted to EPA CAMD on 11/8/2011 as specified in 40 CFR §75.61(a)(3).

The pulverized coal boiler is designed to fire low-sulfur sub-bituminous Powder River Basin coal but uses pipeline quality natural gas as the startup fuel and for flame stabilization up to 25% load. When operating on coal, the boiler is equipped with dry-low NO_x burners and uses overfire air and a Selective Catalytic Reduction system with ammonia injection to control NO_x emissions and a spray dryer absorber with lime injection to control SO_2 emissions.

The facility natural gas supplier contract specifies that the gas will contain no more than 5 grains of total sulfur per 100 standard cubic feet and that the gas heating value will be between 950 and 1050 Btu/scf. Therefore, as allowed under 40 CFR Part 75, Appendix D, Section 2.3.1.4(a)(3), the facility obtained and analyzed one representative sample of the gas fired in the boiler to determine its total sulfur content to be able to demonstrate that the gas initially qualifies as pipeline natural gas. The sample analytical result demonstrating that the total sulfur content of the gas is ≤ 0.5 grains/100scf is provided in Attachment A. In addition, the facility obtained a result of the natural gas analyzed at the gas yard by the supplier gas chromatograph on the same day that the facility grab sample was taken (2/13/13) to demonstrate that the heating value is between 950 and 1100 Btu/scf. This information is also provided in Attachment A.

Due to the forced outage required for boiler repair, the CEMS could not be certified within 180 calendar days of the initial commercial operation date because Unit S01 could not be operated. The unit is now subject to the initial CEMS certification deadline and reporting requirements provided in 40 CFR §75.4(d). SCEA provided notification to EPA CAMD on November 14, 2012 as specified in 40 CFR §75.61(a)(3)(ii) and the unit recommenced commercial operation on November 24, 2012. Under §75.4(d), the deadline for the initial CEMS certification is within 90 unit operating days or within 180 calendar days from the date the unit recommences commercial operation. SCEA intends to certify the boiler CEMS within this applicable deadline.

Under 40 CFR §75.4(d), the facility is required to determine and report SO_2 concentration, NO_x emission rate, CO_2 concentration, and flow rate data for all unit operating hours after the applicable compliance date until all of the required certification tests are successfully completed, using either:

> (1) The maximum potential concentration of SO_2 (as defined in section 2.1.1.1 of 40 CFR Part 75, Appendix A), the maximum potential NO_x emission rate, as defined in 40 CFR §72.2 , the maximum potential flow rate, as defined in section 2.1.4.1 of 40 CFR §75, Appendix A, or the maximum potential CO_2 concentration, as defined in section 2.1.3.1 of 40 CFR Part 75, Appendix A; or
>
> (2) The conditional data validation provisions of 40 CFR §75.20(b)(3); or
>
> (3) Reference methods under 40 CFR §75.22(b); or
>
> (4) Another procedure approved by the Administrator pursuant to a petition under 40 CFR §75.66.

The unit has operated on natural gas for numerous hours since it restarted its commissioning in November 2012. Consequently, pursuant to the requirements of 40 CFR §75.4(d)(4), until the CEMS is certified, SCEA seeks approval to use one of the alternate methodologies listed in the following section to determine and report SO_2, NO_x, and CO_2 emission rates and unit heat input rate during the hours in which the boiler is fired only with natural gas, because these data would be more representative of the actual unit emissions than the maximum values required by 40 CFR Part 75, Appendix A which are based on coal rather than natural gas.

Proposed Natural Gas Alternate Calculation Methodologies

Part 75 requires coal-fired boilers, such as the Unit S01 at Sandy Creek Energy Station, to use CEMS and stack flow methodology to calculate SO_2, NO_x and CO_2 emissions and heat input rate. In addition, Part 75 allows units that fire low sulfur gaseous fuel during startup to use the alternate methodology based on heat input and SO_2 emission factor provided in 40 CFR Part 75, Appendix F, Equation F-23 to calculate SO_2 emissions when firing such fuels.

In order to report emissions during periods of natural gas firing using the CEMS and stack methodology required for coal-fired boilers, while still reporting conservatively high but more representative emissions for the boiler , SCEA consulted with Mr. Robert Vollaro of EPA CAMD who provided guidance on which SCEA developed the alternate methodologies described below. It is anticipated that the use of these maximum default SO_2 and CO_2 concentration values and pro-rated stack flow in the missing data substitution procedure will result in more conservative hourly emissions than the values obtained when using the alternate methodologies provided in Part 75 Appendix D and G for calculating SO_2 and CO_2 emissions from pipeline natural gas combustion. Documentation of how the default values were determined is provided in Attachment B.

The maximum default values to be used while firing coal and/or coal and gas are the ones identified in the facility revised electronic monitoring plan that was submitted to EPA CAMD on 3/26/13 and also documented in the calculations provided in Attachment B. These maximum values were determined as specified in 40 CFR Part 75, Appendix A. A printout of the electronic monitoring plan is provided in Attachment C. SCEA hereby requests EPA CAMD's approval to use fuel specific missing data substitution procedures in order to be able to use the maximum default values for coal and gas separately until the CEMS is certified. The default values for coal will be used as specified in 40 CFR §75.4(d)(1) and the default values for gas will be used in one of the alternate emission calculations listed below.

Pipeline Natural Gas Firing Alternate Calculation Methodology 1: The facility proposes to calculate the emissions using the maximum pro-rated stack flow of 43,582,000 scfh that corresponds to the maximum design heat input rate for the natural gas burner (3,000 MMBtu/hr) and the following emission factors and/or concentrations:

SO_2 emissions – concentration of 0.9 ppmv wet derived from the emission factor provided in the rule (table D-6) for pipeline natural gas when fuel sulfur data is not available, i.e., 0.002 lb/MMBtu and a maximum CO_2 concentration of 7.9% as determined below.

NO_x emissions – emission factor of 0.197 lb/MMBtu based on a maximum NO_x concentration of 100 ppm provided by the manufacturer and a minimum CO_2 concentration of 6.3% wet determined based on the minimum CO_2 concentration of 11.2% for coal and the ratio of the carbon-based F-factors for natural gas and sub-bituminous coal provided in the rule.

CO_2 emissions – default maximum CO_2 concentration of 7.9% determined based on the default maximum CO_2 concentration for coal (14%) and the ratio of the carbon-based F-factors for natural gas (1040 dscf/mmBtu) and sub-bituminous coal (1840 dscf/mmBtu) provided in the rule.

<u>Pipeline Natural Gas Alternate Calculation Methodology 2:</u> The facility proposes to calculate the emissions using the maximum pro-rated stack flow of 43,582,000 scfh that corresponds to the maximum design heat input rate for the natural gas burner (3,000 MMBtu/hr) and the following emission factors and/or concentrations:

SO_2 emissions – default SO_2 maximum concentration of 2.0 ppmv wet specified in 40 CFR §75.11(e)(iii) for very low sulfur fuels.

NO_x and CO_2 emissions - will be calculated the same way as in methodology 1 based on guidance received from EPA CAMD.

<u>Conclusion</u>

SCEA understands that the petition review process may take a few months and has prepared and submitted the 4th Qtr 2012 report using the maximum coal values as required by 40 CFR §75.4(d)(1). However, SCEA respectfully requests that the EPA CAMD hold off on performing the 2012 Acid Rain/CAIR reconciliation that began on March 1, 2013 for unit S01, until the petition is reviewed, the necessary revisions are made to these emission reports and the revised reports are submitted to EPA CAMD.

Should you have any questions or need any additional information to process this petition in a timely manner, please contact Bill Petersen at (254) 896-4317.

Sincerely,

George Scienski
Vice President

ACID RAIN CERTIFICATION STATEMENT

I am authorized to make this submission on behalf of the owners and operators of the source or units for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment.

04/05/2013

Signature Designated Representative	Date

ATTACHMENT A

PIPELINE NATURAL GAS TOTAL SULFUR DOCUMENTATION

HOUSTON LABORATORIES
8820 INTERCHANGE DRIVE
HOUSTON, TEXAS 77054
PHONE (713) 660-0901

Certificate of Analysis

Number: 1030-2013020543-001A

Randy Pike
Energy Transfer Company
1600 N. Jackson
Jacksonville Texas 75766

February 26, 2013

Sample ID:		Sampled By:	GR
Station Name:	Sandy Creek Plant	Sample Of:	Gas
Station Number :	-	Sample Date:	02/13/2013 15:25
Location:	McHerman Co.	Sample Condition:	467.0 psig @ 66.0°F
Sample Point:		PO / Ref. No:	
		COC_No:	H67774

ANALYTICAL DATA

Test	Method	Result	Unit	Detection Limit	Lab Tech.	Date Analyzed
Total Sulfur By UV	ASTM-D-6667	1.4	PPMW	1.0	EM	02/26/13
Total Sulfur By UV	ASTM-D-6667	0.0001	Wt%.		EM	02/26/13
Total Sulfur By UV	ASTM-D-6667	0.044	gr/100 cu.ft.		EM	02/26/13

Comments: Cylinder Number: 4455

Sample On: 02/13/2013 15:25

Hydrocarbon Laboratory Manager

Quality Assurance: The above analyses are performed in accordance with ASTM, UOP or GPA guidelines for quality assurance, unless otherwise stated.

4/3/2013 3:13 PM

R. Pike

ENERGY TRANSFER

Gas Chromatograph Report

from Contract Day 02/13/2013 to Contract Day 02/13/2013

Analysis ID: 056012-00

Analysis Name: SANDY CREEK GAS YARD

Company Name: Transportation

Effective Date	Sat. HV	As Del HV	Dry HV	Meas. HV	Water Content	Wobbe	Real Gravity	C1	C2	C3	IC4	NC4	IC5	NC5	C6	C7	C8	C9	C10	N2	CO2	O2	H2O	H2S	H2	He
02/13/2013 09:00			1015.6			1332.5	0.5809	96.5354	1.4593	0.2647	0.0575	0.0718	0.0310	0.0200	0.0247	0.0184	0.0089	0.0000	0.0000	0.4504	1.0545	0.0000	0.0000	0.0000	0.0000	0.0000
Average:			1015.6				0.5809	96.5354	1.4593	0.2647	0.0575	0.0718	0.0310	0.0200	0.0247	0.0184	0.0089	0.0000	0.0000	0.4504	1.0545	0.0000	0.0000	0.0000	0.0000	0.0000

ATTACHMENT B
COAL AND NATURAL GAS PROPOSED EMISSION CALCULATIONS

Proposed Emissions Calculations for Sandy Creek

The calculation methodologies provided below were derived based on guidance received from Robert Vollaro of EPA CAMD. The NO_x emission calculations were slightly modified to incorporate the minimum CO_2 wet concentration estimated based on the minimum CO_2 dry concentration of 13.39% and maximum moisture concentration of 16.1% used to estimate the MPF of 134,058,000 scfh identified in the electronic monitoring plan and to include more realistic NO_x maximum emission rates for coal and pipeline natural gas, estimated using manufacturer NO_x MPC rather than Part 75 NO_x MPC default values for these fuels.

<u>SO_2 Emissions</u>

For any hour(s) in which coal was combusted after the unit recommenced operation in November 2012 and before the CEMS is certified in 2013, the MPC for coal must be used in the SO_2 emissions calculations along with the maximum potential flow rate for coal combustion. As identified in the electronic monitoring plan provided in Attachment C, the coal SO_2 MPC is 758.6 ppmv wet and the coal MPF is 134,058,000 scfh. Since the SO_2 monitor measures on a wet basis, Equation F-1 from Appendix F of Part 75 will be used to calculate the SO_2 emission rate in lb/hr. The unit DAHS Part 75 software will calculate the coal SO_2 emissions in tons using these maximum values and the actual unit operating hours firing coal.

For hours in which natural gas was combusted, the MPC for natural gas must also be used in the emissions calculations, along with the maximum potential flow rate for natural gas combustion. These values are significantly lower than the MPC and MPF for coal combustion.

The following methodology will be used to calculate the SO_2 emissions for the natural gas combustion since the facility is able to document that the gas meets the Part 72 definition of pipeline natural gas (PNG).

The maximum potential SO_2 emission rate for PNG combustion is 0.002 lb/MMBtu, according to Table D-6 in Appendix D of Part 75. To convert this to an equivalent stack gas concentration, a modified version of Equation F-6 in Appendix F is used, where C_h is the SO_2 concentration (ppm) , and the K factor is 1.660×10^{-7} lb/scf-ppm SO_2. The maximum potential CO_2 concentration for PNG combustion must be used in this calculation. To obtain the CO_2 MPC for PNG, the coal-fired MPC (i.e., 14% CO_2, from Appendix A, section 2.1.3.1) was multiplied by the ratio of the carbon-based F-factors for natural gas and sub-bituminous coal resulting in a PNG MPC of 7.9% CO_2.

$$(MPC)_{PNG} = (1040/1840)\,(14\%\ CO_2) = 7.9\%\ CO_2$$

Rearranging Equation F-6 and solving it for SO_2 concentration, the PNG SO_2 MPC is determined to be 0.9 ppmv wet.

$$c_h = \frac{(E)(\%CO_2)}{100\,(K)(F_c)} = \frac{(0.002)(7.9)}{100\,(1.66\,x\,10^{-7})\,(1040)} = 0.9\ ppm\ SO_2$$

When a unit with an SO_2 monitor combusts natural gas, very low SO_2 concentrations (sometimes zero or even negative) are often recorded. Part 75 requires all readings below 2 ppm to be reported as 2 ppm. Therefore, another option (recommended by EPA CAMD) is to use 2 ppm as the MPC for SO_2 when PNG is combusted.

To determine the SO_2 mass emissions from PNG combustion in 2012/2013, the facility will substitute the SO_2 MPC and MPF into Equation F-1 to calculate the SO_2 emission rate in lb/hr. The MPF for PNG combustion is less than the MPF for coal because the unit's heat input rate can only reach 3,000 MMBtu/hr on PNG, as opposed to 8,185 MMBtu/hr on coal. The coal MPF is 134,058,000 scfh, which corresponds to the maximum hourly heat input of 8,185 MMBtu/hr at normal CO_2 concentrations. The corresponding MPF for PNG at 8,185 MMBtu/hr can be approximated by the ratio of the dry-basis F-factors for PNG and sub-bituminous coal as indicated in the following equation:

$$(\text{MPF})_{\text{PNG}} = (134{,}058{,}000)\,(8710/9820) = 118{,}905{,}000 \text{ scfh}$$

However, the unit can only reach 3,000 MMBtu/hr when PNG is combusted. Therefore, the MPF must be multiplied by the ratio of 3,000 MMBtu/hr to 8,185 MMBtu/hr. In view of this, the appropriate MPF for PNG combustion is estimated to be:

$$(118{,}905{,}000)\,(3{,}000/8{,}185) = 43{,}582{,}000 \text{ scfh}$$

Substituting the PNG SO_2 MPCs and the MPF determined above into Equation F-1, the two alternate SO_2 emission rates in lb/hr for PNG combustion would be:

$$E = K\,C_{SO2}\,Q = (1.66 \times 10^{-7} \text{ lb/scf-ppm})\,(0.9 \text{ ppm})\,(43{,}582{,}000 \text{ scfh})$$
$$E = 6.5 \text{ lb/hr}$$

$$E = K\,C_{SO2}\,Q = (1.66 \times 10^{-7} \text{ lb/scf-ppm})\,(2 \text{ ppm})\,(43{,}582{,}000 \text{ scfh})$$
$$E = 14.5 \text{ lb/hr}$$

The unit DAHS Part 75 software will calculate the PNG SO_2 emissions in tons using one of these maximum values (whichever approved) and the actual unit operating hours firing PNG.

CO_2 Emissions

For coal-fired hours, Equation F-11 from Appendix F of Part 75 will be used to calculate the CO_2 mass emission rate in tons/hr by substituting the coal MPF and maximum CO_2 default values specified above. The K-factor to be used in the equation is 5.7×10^{-7} tons/scf-%CO_2. The unit DAHS Part 75 software will calculate the coal CO_2 emissions in tons using these maximum values and the actual unit operating hours firing coal.

For PNG combustion, Equation F-11 will also be used, except that the MPF value is 43,582,000 scfh and the MPC is 7.9% CO_2, as determined above. This will result in a CO_2 mass emission rate of 196.2 tons/hr.

$$E_{CO2} = K\ (C_{CO2})\ (Q) = (5.7 \text{ x } 10^{-7})\ (7.9)\ (43{,}582{,}000)\ =\ 196.2 \text{ tons/hr}$$

This emission rate is higher than the one that would be obtained from Appendix G, but it is preferred because it uses CEMS-based concepts and a CEMS equation. The unit DAHS Part 75 software will calculate the PNG CO_2 emissions in tons using these maximum values and the actual unit operating hours firing PNG.

NO_x Emissions

Equation F-6 from Appendix F of Part 75 will be used to calculate the maximum potential NO_x emission rate in lb/MMBtu. In Equation F-6, the NO_x concentration must be the MPC, and the CO_2 concentration may either be the minimum CO_2 during normal operation (excluding startup, shutdown, and upsets) or the diluent cap value.

For coal combustion, the NO_x MPC identified in the electronic monitoring plan is 600 ppm. This value was provided by the boiler manufacturer. The minimum CO_2 concentration is 11.2% CO_2 .based on the minimum dry CO_2 concentration of 13.39% and maximum moisture concentration of 16.1% used to estimate the MPF of 134,058,000 scfh also identified in the electronic monitoring plan. Therefore, the maximum potential NO_x emission rate (MER) for coal would be:

$$E = K\ C_{NOx}\ F_c\ \frac{100}{\%CO_2} = 1.194\ x\ 10^{-7} * 600 * 1840 * \frac{100}{11.2} = 1.177\ lb/mmBtu$$

For PNG combustion, in the absence of actual measured NO_x concentrations or manufacturer estimated NO_x MPC, the facility would be required to use 600 ppm (default from Table 2-1 in section 2.1.2.1 of Appendix A) as the NO_x MPC. To estimate the minimum CO_2 concentration for PNG combustion, the estimated minimum value for coal was multiplied by the ratio of the carbon-based F-factors for natural gas and sub-bituminous coal, i.e., 11.2% CO_2 (1040/1840) = 6.3% CO_2. Therefore, the NO_x MER for PNG would be:

$$E = K\ C_{NOx}\ F_c\ \frac{100}{\%CO_2} = 1.194\ x\ 10^{-7} * 600 * 1040 * \frac{100}{6.3} = 1.183\ lb/mmBtu$$

This NO_x emission rate is grossly overstated (likely by a factor of 4 or more). In view of this the facility obtained quality-assured NO_x concentration data from the CEMS while the unit was combusting only PNG during the period of 2/16/13 through 3/22/13, to determine a more realistic NO_x MPC value and avoid substantial over-reporting of the NO_x mass emissions. Based on the data provided in Attachment D, the PNG NO_x MPC would be 45 ppm. However, to be conservative, the facility will use in the calculations the NO_x MPC value of 100 ppm provided by the burner manufacturer (documentation also provided in Attachment D). Therefore, the more realistic NO_x MER for PNG would be:

$$E = K\ C_{NOx}\ F_c\ \frac{100}{\%CO_2} = 1.194\ x\,10^{-7}\ *100*1040*\frac{100}{6.3} = 0.197\ lb/mmBtu$$

The hourly NO_x mass emission rate in lb/hr will be calculated using Equation F-24a in Appendix F (i.e., as the product of the NO_x emission rate and heat input rate). In this equation, the NO_x emission rate will be the fuel-specific MER determined above and the heat input rate will be the maximum rated hourly heat input calculated based on each fuel MPF and CO2 MPC identified above using Equation F-15. These calculated heat input rates will be conservatively higher than the maximum design heat input rate for the gas burner (i.e., 3,000 MMBtu/hr) and coal-fired boiler (i.e., 8,185 MMBtu/hr).

Using the MER values calculated above, the hourly NO_x maximum emission rate for coal and PNG combustion would be:

Coal: 1.177 lb/MMBtu x 10200.1 MMBtu/hr = 12,006 lb/hr

PNG: 0.197 lb/MMBtu x 3310.6 MMBtu/hr = 652 lb/hr

The unit DAHS Part 75 software will calculate the coal and PNG NO_x emissions in tons using these maximum values and the actual unit operating hours firing each fuel.

ATTACHMENT C
PRINTOUT OF ELECTRONIC MONITORING PLAN

ECMPS Client Tool

Version 1.0 2013 Q1

Monitoring Plan Printout Report

March 26, 2013 03:32 PM

Facility Name: Sandy Creek Energy Station

Facility Details

Facility ID (ORISPL):	56611
Monitoring Plan Location IDs:	S01
State:	TX
County:	McLennan
Latitude:	31.4641
Longitude:	-96.9575

Reporting Frequency

Monitoring Plan Location IDs	Reporting Frequency	Begin Quarter	End Quarter
S01	Q - Quarterly	2012 QTR 4	

Monitoring Location Attributes

Unit/Stack/Pipe Identifier	Duct Indicator	Ground Elevation	Stack Height	Cross Area Exit	Cross Area Flow	Material Code	Shape Code	Begin Date	End Date
S01		480	360	615	615	OTHER	ROUND	11/04/2012	

Unit Operation Information

Unit Identifier	Non-Load Based Ind	Commence Commercial Operation Date	Commence Operation Date	Boiler/Turbine Type			Max Heat Input		
				Code	Begin Date	End Date	Value (mmBtu)	Begin Date	End Date
S01	0	10/10/2011	10/10/2011	DB	10/10/2011		8185.0	10/10/2011	

Unit Type Codes: DB - Dry bottom wall-fired boiler

Unit Program Information

Unit Identifier	Program Code	Unit Class	Unit Monitor Certification Begin Date	Unit Monitor Certification Deadline
S01	ARP	P2	10/10/2011	04/07/2012
	CAIRNOX	A	10/10/2011	04/07/2012
	CAIRSO2	A	10/10/2011	04/07/2012
	TRNOX	A	01/01/2012	04/07/2012
	TRNOXOS	A	05/01/2012	05/01/2012
	TRSO2G2	A	01/01/2012	04/07/2012

Unit Fuel

Unit Identifier	Fuel Type	Fuel Indicator	Demonstration Method for GCV	Demonstration Method for Daily Sulfur	Ozone Season Indicator	Begin Date	End Date
S01	C	P				11/04/2012	
	PNG	I				11/04/2012	

Fuel Type Codes:
PNG - Pipeline Natural Gas
C - Coal

Fuel Indicator Codes:
P - Primary
I - Ignition (Startup)

Unit Controls

Unit Identifier	Parameter	Control Equipment	Original Ind	Seasonal Ind	Installation Date	Optimization Date	Retirement Date
S01	PART	B	Y				
	SO2	DL	Y				
	NOX	SCR	Y				

Control Equipment Descriptions:
SCR - Selective Catalytic Reduction
DL - Dry Lime FGD
B - Baghouse

Monitoring Method

Unit/Stack/Pipe Identifier	Parameter	Methodology	Substitute Data Approach	Bypass Approach Code	Begin Date/Hour	End Date/Hour
S01	CO2	CEM	SPTS		11/04/2012 00	
	HI	CEM	SPTS		11/04/2012 00	
	NOX	NOXR			11/04/2012 00	
	NOXR	CEM	SPTS		11/04/2012 00	
	OP	COM			11/04/2012 00	
	SO2	CEM	SPTS		11/04/2012 00	

Parameter Codes:
SO2 - SO2 Hourly Mass Rate (lb/hr)
OP - Opacity
NOXR - NOx Emission Rate (lb/mmBtu)
NOX - NOx Hourly Mass Rate (lb/hr)
HI - Heat Input Rate (mmBtu/hr)
CO2 - CO2 Hourly Mass Rate (ton/hr)

Methodology Codes:
NOXR - NOx Mass Calculated from NOx Emission Rate
COM - Continuous Opacity or Particulate Matter Monitor
CEM - Continuous Emission Monitor

Substitute Data Codes:
SPTS - Standard Part 75 for Missing Data

Monitoring System / Analytical Components

Unit/Stack /Pipe Identifier	System					Component								
	ID	Type	Des	Begin Date/Hour	End Date/Hour	ID	Type	SAM	BAS	Manufacturer	Model or Version	Serial Number	Begin Date/Hour	End Date/Hour
S01	101	SO2	P	11/04/2012 00		001	PRB	DIL		M&C PRODUCTS	SP2000H/DIL	17356/2006875	11/04/2012 00	
						003	DAHS			VIM TECHNOLOGIES	CEMLINK	4294	11/04/2012 00	
						006	SO2	DIL	W	THERMO	43I	CM10140002	11/04/2012 00	
	102	NOX	P	11/04/2012 00		001	PRB	DIL		M&C PRODUCTS	SP2000H/DIL	17356/2006875	11/04/2012 00	
						003	DAHS			VIM TECHNOLOGIES	CEMLINK	4294	11/04/2012 00	
						004	NOX	DIL	W	THERMO	42I	CM10140003	11/04/2012 00	
						009	CO2	DIL	W	THERMO	410I	CM1011741709	11/04/2012 00	
	103	CO2	P	11/04/2012 00		001	PRB	DIL		M&C PRODUCTS	SP2000H/DIL	17356/2006875	11/04/2012 00	
						003	DAHS			VIM TECHNOLOGIES	CEMLINK	4294	11/04/2012 00	
						009	CO2	DIL	W	THERMO	410I	CM1011741709	11/04/2012 00	
	104	FLOW	P	11/04/2012 00		003	DAHS			VIM TECHNOLOGIES	CEMLINK	4294	11/04/2012 00	
						008	FLOW	DP	W	EMRC	TBD	TBD	11/04/2012 00	
	105	OP	P	11/04/2012 00		003	DAHS			VIM TECHNOLOGIES	CEMLINK	4294	11/04/2012 00	
						010	OP	IS		DURAG	290	1213369	11/04/2012 00	

System Types Descriptions:
SO2 - SO2 Concentration
NOX - NOx Emission Rate
CO2 - CO2 Concentration
FLOW - Stack Flow
OP - Opacity

System Designations Descriptions:
P - Primary

Sample Acquisition Method (SAM):
IS - In Situ
DP - Differential Pressure
DIL - Dilution

Component Types Descriptions:

PRB - Probe
DAHS - Data Acquisition and Handling System
SO2 - SO2 Concentration
NOX - NOx Concentration
CO2 - CO2 Concentration
FLOW - Stack Flow Analyzer
OP - Opacity Monitor

Analyzer Range Data

Unit/Stack/Pipe Identifier	Component Type	Component ID	Range Code	Dual Range Indicator	Begin Date/Hour	End Date/Hour
S01	CO2	009	High Range		11/04/2012 00	
	NOX	004	Auto Ranging	Y	11/04/2012 00	
	SO2	006	Auto Ranging	Y	11/04/2012 00	

Component Types Descriptions:

CO2 - CO2 Concentration
NOX - NOx Concentration
SO2 - SO2 Concentration

Emissions Formulas

Unit/Stack/Pipe Identifier	Parameter	Formula ID	Formula Code	Formula	Begin Date/Hour	End Date/Hour
S01	SO2	F01	F-1		11/04/2012 00	
	NOXR	F02	F-6		11/04/2012 00	
	CO2	F03	F-11		11/04/2012 00	
	HI	F04	F-15		11/04/2012 00	
	NOX	F05	F-24A		11/04/2012 00	

Parameter Codes Descriptions:

SO2 - SO2 Hourly Mass Rate (lb/hr)
NOXR - NOx Emission Rate (lb/mmBtu)
CO2 - CO2 Hourly Mass Rate (ton/hr)
HI - Heat Input Rate (mmBtu/hr)
NOX - NOx Hourly Mass Rate (lb/hr)

Formula Codes Descriptions:

F-6 - NOXR/SO2R (from NOX or SO2 wet, CO2 wet, Fc)
F-24A - NOX (from NOX rate, HI)
F-15 - HI (from wet CO2, flow, Fc)
F-11 - CO2 (from CO2 wet, flow)
F-1 - SO2 (from SO2 wet, flow)

Span Values

Unit/Stack /Pipe Identifier	Comp Type	Scale	Method	MPC/ MPF	MEC	Span Value	Full-Scale Range	Units of Measure	Scale Transition Point	Def. High Range Value	Flow Full Range (SCFH)	Flow Span Value (SCFH)	Begin Date/Hour	End Date/Hour
S01	CO2	H	TB	14.0		20.000	20.000	PCT					11/04/2012 00	
	FLOW		F	134058000		2.500	2.500	INH2O			150000000	150000000	11/04/2012 00	
	NOX	H	ME	600.0	62.0	700.000	700.000	PPM	98.0				11/04/2012 00	
	NOX	L	PL		62.0	100.000	100.000	PPM	98.0				11/04/2012 00	
	SO2	H	F	759.0	75.9	1000.000	1000.000	PPM	98.0				11/04/2012 00	
	SO2	L	OL		75.9	100.000	100.000	PPM	98.0				11/04/2012 00	

Component Types Descriptions:
CO2 - CO2 Concentration
FLOW - Stack Flow Analyzer
NOX - NOx Concentration
SO2 - SO2 Concentration

Span Method Codes Descriptions:
TB - Table Defaults from Part 75
PL - Permit Limit for NOX MEC
OL - Other Limit
ME - Manufacturer's Estimate for NOX MPC
F - Formula

Units of Measure Descriptions:
PPM - Parts per Million
PCT - Percentage
INH2O - Inches of Water

Unit/Stack/Pipe Load or Operating Level Information

Unit/Stack/Pipe Identifier	Maximum Hourly Load	Units of Measure	Upper Bound of Range of Operation	Lower Bound of Range of Operation	Designated Normal Op. Level	Second Most Frequently Used Op. Level	Second Normal Indicator	Load Analysis Date	Begin Date/Hour	End Date/Hour
S01	988	MW	988	383	High	Mid	Yes	10/10/2011	10/10/2011 00	

Units of Measure Descriptions: MW - Megawatt

Monitoring Defaults

Unit/Stack/Pipe Identifier	Parameter	Value	Units of Measure	Purpose Code	Fuel Type	Operating Condition	Source of Value	Begin Date/Hour	End Date/Hour
S01	CO2N	5.0000	PCT	DC	NFS	A	DEF	11/04/2012 00	
	NORX	1.1770	LBMMBTU	MD	NFS	A	MAXD	11/04/2012 00	

Parameter Codes Descriptions:
NORX - Maximum NOx Emission Rate (lb/mmBtu)
CO2N - CO2 Minimum Concentration (pct)

Units of Measure Descriptions:
PCT - Percentage
LBMMBTU - Pounds / mmBtu

Purpose Codes Descriptions:
MD - Missing Data (or Unmonitored Bypass Stack or Emergency Fuel) Default
DC - Diluent Cap

Fuel Type Codes Descriptions: NFS - Non-Fuel Specific

Operating Conditions Descriptions: A - Any Hour

Source Codes Descriptions:
MAXD - Maximum Value based on Design
DEF - Default Value from Part 75

ATTACHMENT D
FACILITY 2013 NOx CEMS DATA and GAS BURNER MANUFACTURER NOx MPC ESTIMATE

WORST CASE NATURAL GAS (no coal)

Data obtained from the Part 75 database.
CEMS calibrated but not certified

Natural Gas NOx Default Value: **44.8** ppm
(filtered hours in which natural gas was the only fuel fired in the boiler)

TDATETIME	PROCESS CODE	UNIT OPERATING TIME	Stk_NOx_P75__ppm_	Stk_Coal_Feed__klb_hr_	Stk_Nat_Gas_Feed__klb_hr_	_Unit_MW
3/9/13 2:59 AM	3	0.75	35.7	0	74.7	74
3/9/13 3:59 AM	3	1	40.1	0	80.5	121
3/9/13 4:59 AM	3	1	42.7	0	82.8	150
3/9/13 5:59 AM	3	1	33.7	0	83.1	150
3/9/13 6:59 AM	3	1	31.9	0	82.3	150
3/13/13 9:59 AM	8	0.27	0	0	0	2
3/15/13 6:59 PM	4	0.9	42.6	0	67	104
3/22/13 2:59 AM	3	0.02	27.3	0	54.3	16
3/22/13 3:59 AM	3	1	35.1	0	68.9	82
3/22/13 4:59 AM	3	1	36.4	0	71.9	95
3/22/13 5:59 AM	3	1	42.3	0	80.9	150
3/22/13 6:59 AM	3	1	44.8	0	87.2	150

Information Request

IR# 210.0

Sandy Creek Services (SCS) (Open)
Sandy Creek Power Project

Date: 02/06/2013

**Safety Related: No
From: Nelson Eichelberger
Discipline: Engineering
Email: neichelberger@sandycreekservices.com

Rev 0 --

To: SCPP *Requested Response Date:* 2/20/13

Subject: NO_x production of gas igniters during commissioning

Description:
Owners are currently estimating emissions during commissioning in order to secure the appropriate number of allowances. Owners desire a statement from IHI estimating NO_x production (in lb/MMBtu) of the gas igniters when firing only on gas. If Owners do not receive this statement, Owners will be required to utilize EPA estimates, which may grossly overestimate NO_x production at SCES and subsequently cause Owners to incur additional costs. Your attention to this matter would be most appreciated.

To: SCS
Response from: SCPP

IHI has advised that the NOx emissions while firing only on natural gas is estimated to be approximately 100 ppm (6% O2 basis) at the economizer outlet during unit startup. This value can vary considerably due to a number of conditions, including fuel properties, combustion air temperature, fuel flow, and excess air ratio.

Response by: Mike McCollam
Date of Response: 14-Feb-13

Rev 1--

To: SCPP

SCS Response:

Response by:

Date of Response:

To: SCS

Response from: SCPP

Response by:

Date of Response:

Rev 2--

To: SCPP Requested Response Date:

SCS Response:

Response by:

Date of Response:

To: SCS
Response from: SCPP:

MODELING ANALYSIS TO DETERMINE ONE-HOUR AVERAGE AMBIENT SULFUR DIOXIDE CONCENTRATIONS POTENTIALLY ATTRIBUTABLE TO EMISSIONS FROM SANDY CREEK ENERGY STATION

SUBMITTED TO:

SANDY CREEK SERVICES, LLC
2161 RATTLESNAKE ROAD
RIESEL, TEXAS 76682

PREPARED BY:

CURTIS HARDER, P.E., AND KANWAR BHARDWAJ
ZEPHYR ENVIRONMENTAL CORPORATION
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2600 VIA FORTUNA, SUITE 450
AUSTIN, TEXAS 78746-6544

Curtis A. Harder

STATE OF TEXAS
CURTIS A. HARDER
60692
REGISTERED PROFESSIONAL ENGINEER

06/05/2015

JUNE 2015

zephyr

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APPENDICES

APPENDIX A: PLOT PLAN

1.0 INTRODUCTION

Sandy Creek Services, LLC (SCS) operates the Sandy Creek Energy Station (SCES), a pulverized coal-fired electric power generation facility located near Riesel in McLennan County, Texas. SCES operates under New Source Review (NSR) Permit Numbers 70861 and PSDTX1039 issued by the Texas Commission on Environmental Quality (TCEQ).

This following report documents an ambient air quality analysis (AQA) that Zephyr Environmental Corporation (Zephyr) conducted in 2011 to determine whether site-wide emissions of sulfur dioxide (SO_2) from the SCES may cause or contribute to an exceedance of the one-hour National Ambient Air Quality Standard (NAAQS) for SO_2. Zephyr conducted the modeling analysis in accordance with the methodologies and procedures prescribed by the modeling staff of the TCEQ and U.S. Environmental Protection Agency (EPA). The analysis undertaken in 2011 is being formally documented at this juncture in response to a March 20, 2015 EPA solicitation of information relevant to performing attainment designations with respect to the one-hour SO_2 NAAQS in the vicinity of various power plants, including the SCES.

2.0 MODELING METHODOLOGY

2.1 GENERAL MODELING ANALYSIS APPROACH

The general approach to conducting the AQA consisted of assessing the worst-case contribution from SCES's emission sources to ambient air SO_2 concentrations, assessing the maximum contribution from other emission sources, and then summing those maximum contributions together for comparison to the one-hour NAAQS for SO_2.

Zephyr used the maximum allowable hourly emission rates for the boiler stacks to assess SCES's worst-case contribution to ambient air SO_2 concentrations. A plot plan showing the names and locations of SCES's SO_2 emission points relative to the plant's property boundary is provided as Appendix A of this report.

Based on the review and analysis of existing ambient air monitoring data, Zephyr accounted for contributions from other nearby SO_2 sources by establishing a maximum ambient air concentration representative of the existing background in the vicinity of SCES. The representative background concentration was added to the maximum concentration predicted for SCES's SO_2 emission sources in order to calculate a maximum possible SO_2 concentration that could be compared to the NAAQS.

2.2 CHOICE OF DISPERSION MODEL

The American Meteorological Society / Environmental Protection Agency Regulatory Model (AERMOD) is the latest regulatory atmospheric dispersion model suitable for industrial sources and is the model preferred by the EPA for demonstrations of compliance with the one-hour SO_2 NAAQS. As specified by EPA and TCEQ modeling guidance current when the AQA was conducted, Zephyr used Version 11103 of AERMOD to perform the dispersion modeling for the analysis. To facilitate the running of AERMOD, Zephyr used the "BEE-Line BEEST for Windows" graphic user interface.

2.3 TERRAIN CONSIDERATIONS

In accordance with TCEQ and EPA guidance, Zephyr used U.S. Geological Survey (USGS) Digital Elevation Map (DEM) files to determine elevations of the emission sources and structures capable of downwashing source plumes at the site, as well as elevations of the off-property locations, known as receptors, at which ambient air SO_2 concentrations were calculated. The DEM files, each with a 30-meter resolution, were obtained from the Texas Natural Resources Information System (TNRIS). Using these topographical data, Zephyr ran AERMAP, AERMOD's terrain data pre-processor as implemented through the BEEST graphical user interface, to calculate elevations for each source and building and to calculate the elevation and hill height scale for each receptor.

2.4 BUILDING WAKE EFFECTS

Zephyr simulated downwash effects of plant structures on source plumes using guidance provided in the *User's Guide to the Building Profile Input Program* (EPA, October 1993). The EPA currently requires that all building downwash be determined using the EPA Building Profile Input Program (BPIPPRM) computer subroutine program.

Zephyr used "BEE-Line BEEST for Windows" computer interface to run the BPIPPRM subroutine (Version 04274) in order to calculate downwash parameter values for the analysis. This was accomplished by entering structure dimension and orientation data into the user interface so that the BPIPPRM subroutine would calculate downwash parameter values for each point source and then would automatically insert the values into the AERMOD input files in the appropriate locations and formats.

2.5 RECEPTOR GRIDS

Zephyr developed receptor grids for the AQA in accordance with general guidance provided by the TCEQ modeling staff for conducting modeling analyses to support NSR permit applications. Specifically, Zephyr used the 1983 North American Datum (NAD83) geodetic coordinate reference system to calculate Universal Transverse Mercator (UTM) coordinates for the modeling receptor grids. The receptor coverage utilized for the AQA consisted of the following:

- Receptors spaced 25 meters apart, extending to 200 meters from the legal property boundary
- Receptors spaced 100 meters apart, extending to 1,000 meters from the legal property boundary
- Receptors spaced 500 meters apart, extending to 5,000 meters from the legal property boundary.

The location of the highest one-hour concentrations predicted by AERMOD for the modeling analysis occurred northwest and northeast of the plant sources, all within 700 meters of the property line, with the highest concentration predicted to occur 350 meters from the property line to the northwest. Concentrations predicted for receptors from 350 meters to 5,000 meters from any property boundary steadily decreased with distance in every direction. Accordingly, running AERMOD to predict concentrations for receptors located beyond 5,000 meters from the property line was unwarranted.

2.6 METEOROLOGICAL DATA

To provide representative meteorological data for McLennan County in order to support dispersion modeling requirements, the TCEQ staff has prepared pre-processed AERMOD meteorological data sets using National Weather Service (NWS) surface data from Waco Regional Airport and NWS upper air data from Stephenville. The meteorological data sets made available by TCEQ consist of a set for each of three ranges of surface roughness length, characterized as "low", "medium", and "high". In order to select the appropriate meteorological data set for the relevant modeling domain, Zephyr utilized the EPA's AERSURFACE program to determine the surface roughness length for the SCES site. AERSURFACE requires the input of land cover data from USGS National Land Cover Data 1992 archives (NLCD92), which are used to determine land cover types in the immediate vicinity of the modeled emission sources. Based on the AERSURFACE program, a surface roughness of 0.135 meters (m) was calculated for the SCES site. Because this value falls within the 0.1-to-0.7-m range stated in the TCEQ's AERMOD training document, the "medium surface roughness" meteorological data set was selected for use in the modeling analysis.

For the one-hour SO_2 modeling analysis, Zephyr input into AERMOD five years (1985, 1987, 1988, 1989, and 1990) of the TCEQ-specified meteorological data.

2.7 AIR QUALITY MONITORING DATA

In accordance with EPA and TCEQ guidance for SO_2 NAAQS compliance demonstrations, a representative existing ambient air background concentration must be established. The representative background concentration is to be added to the maximum concentration predicted by AERMOD for new SO_2 emission sources in order to calculate a maximum possible SO_2 concentration that can be compared to the NAAQS. To establish a background concentration, Zephyr reviewed ambient air quality monitoring data available on the TCEQ's *Air Quality Data* website and the EPA's *AirData* website (http://www.epa.gov/air/data/). Based on this review, Zephyr selected ambient air SO_2 concentration data collected at the Waco Mazanec monitor station (TCEQ Continuous Air Monitoring Station 1037; EPA ID 48-309-1037) to calculate a representative background concentration for use in the NAAQS compliance demonstration.

In accordance with EPA and TCEQ guidance, the SO_2 background concentration (in micrograms per cubic meter ($\mu g/m^3$)) was calculated using the methodology specified for calculating the design value for the one-hour SO_2 NAAQS. This methodology consists of calculating the average of the 99th percentile of the daily maximum one-hour SO_2 concentrations for the three most recent years of measurements for which EPA/TCEQ minimum data collection criteria have been met. The background concentration calculated for the modeling analysis is presented in Table 2-1.

Table 2-1: Background SO_2 Concentration and Averaging Method

Pollutant	Monitor Station	County	Averaging Period	Concentration ($\mu g/m^3$)	Averaging Method for Concentration
SO_2	Waco Mazanec	McLennan	1-Hour	16.8	Three-year average of 99th percentile of the daily one-hour maximum concentrations for the period 2008-2010

3.0 MODELING EMISSIONS INVENTORY

The SCES SO_2 emission sources modeled in the AQA are presented in Table 3-1, along with each source's SO_2 emission rate.

Note that modeled emission rates for Emission Point Numbers (EPNs) S33 and S34 do not match current permit allowable emission rates; however, because these sources are considered intermittent due to their emergency status (i.e., they are operated in a non-emergency mode for much less than 100 hours per year), current TCEQ modeling guidance for a one-hour SO_2 NAAQS compliance demonstration allows for these sources to be modeled using annual average SO_2 emission rates in lieu of the permit allowable hourly rates. Therefore, because modeled emission rates for each of these engines exceeded the permit allowable annual emission rates, the modeling results are conservative.

Table 3-2 presents modeled stack exit parameter values for SCES sources. All combustion sources were modeled as point sources using values for exhaust parameters (i.e., stack exit velocities, diameters, and temperatures) obtained from SCES. The model uses stack parameter values to calculate the buoyancy and momentum rise of the emission plumes. All combustion exhausts were treated in the modeling analysis as being released vertically.

Table 3-1: Modeled SO_2 Emission Rates

EPN	Source Description	Modeled Hourly Emission Rate (lb/hr)
S01	Pulverized Coal Boiler	2,892 [1]
S02	Auxiliary Boiler	0.17
S33	Diesel-fired Emergency Generator	0.029
S34	Emergency Diesel Fuel-Fired Firewater Pump	0.029
S40	Emergency Diesel Fuel-Fired Firewater Booster Pump	0.029

[1] Corresponds to startup mode

Table 3-2: Modeled Stack Exit Parameter Values

EPN	Easting (X) (m)	Northing (Y) (m)	Base Elevation (m)	Exit Height (ft)	Exit Temperature (F)	Exit Velocity (fps)	Exit Diameter (ft)
S01	694,227	3,484,006	146.6	360.0	165.0	65.0	27.80
S02	694,071	3,484,039	146.6	265.0	300.0	135.0	5.00
S33	693,999	3,483,915	146.6	35.0	835.0	254.9	0.92
S34	694,086	3,484,089	146.6	13.0	844.0	160.4	0.50
S40	694,025	3,483,924	146.6	13.0	846.0	34.7	0.50

4.0 MODELING RESULTS

Table 4-1 summarizes the results of the AERMOD modeling conducted for the SCES SO_2 sources. The table lists:

- The maximum ground-level one-hour SO_2 concentration (in µg/m^3) predicted by AERMOD modeling for ambient air contributions from SCES SO_2 sources;
- The calculated maximum one-hour SO_2 concentration determined to be representative of the existing background air quality in the vicinity of SCES; and
- The sum of the two values listed above to estimate the maximum possible total ambient one-hour SO_2 concentration in the vicinity of SCES.

The table compares the predicted maximum total ambient one-hour SO_2 concentration for the area to the one-hour SO_2 NAAQS. The predicted maximum concentration is easily compliant with the NAAQS.

Table 4-1: Modeling Results

Pollutant	Averaging Period	Predicted Maximum Concentration Resulting from SCES Emissions Alone (µg/m^3)	Existing Background Concentration (µg/m^3)	Predicted Maximum Total Concentration (µg/m^3)	NAAQS (µg/m^3)
SO_2	one-hour	117 [1]	16.8 [2]	134	196

[1] As prescribed by the TCEQ and EPA, this value is calculated as the five-year average of the 99th percentile of the predicted daily maximum one-hour concentrations.

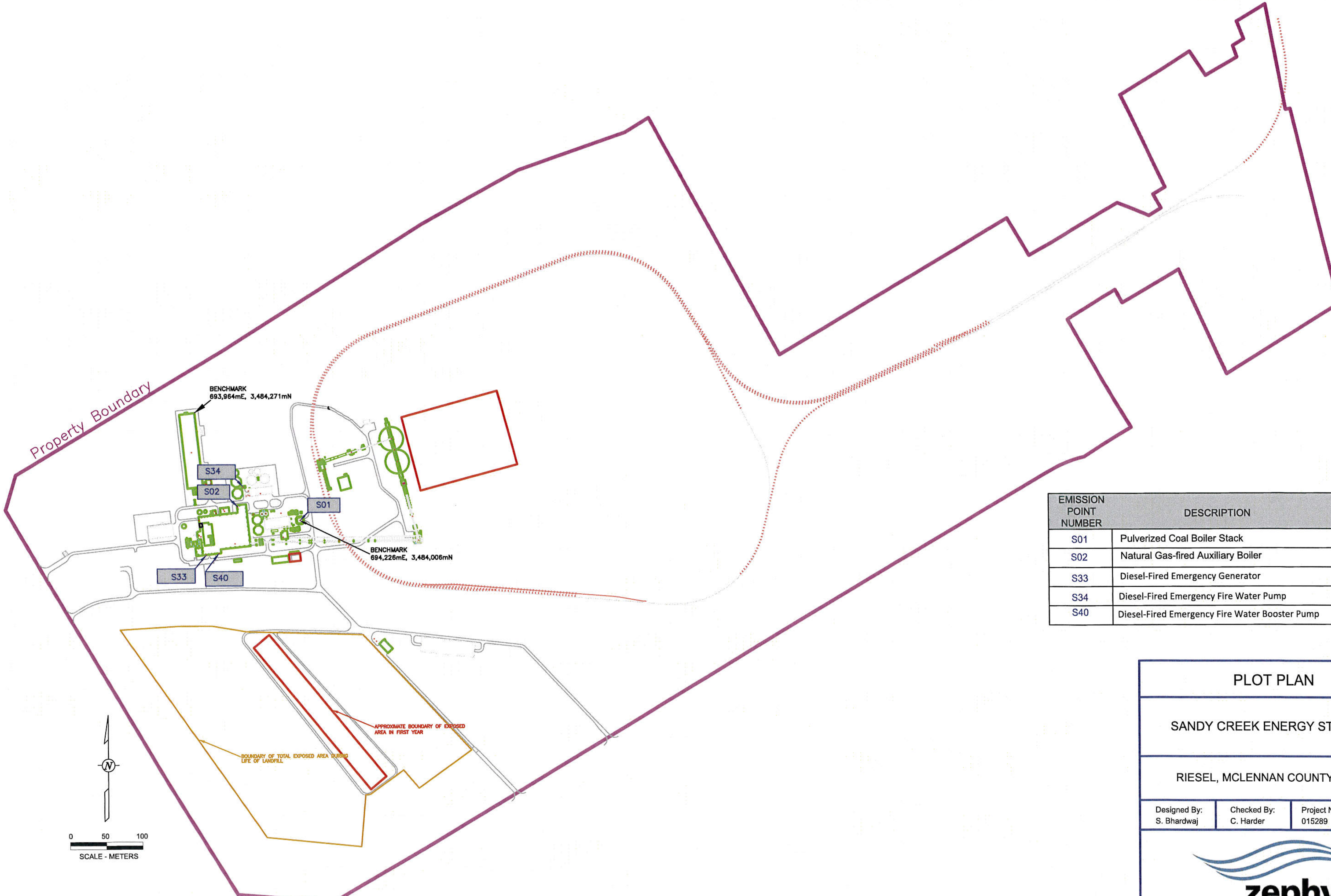
[2] As prescribed by the TCEQ and EPA, this value is calculated as the three-year average of the 99th percentile of the measured daily maximum one-hour concentrations.

5.0 CONCLUSIONS

Based on the modeling analysis conducted by Zephyr in 2011 as documented in this report, SO_2 emissions from SCES do not cause or contribute to an exceedance of the one-hour SO_2 NAAQS.

APPENDIX A

PLOT PLAN



EMISSION POINT NUMBER	DESCRIPTION
S01	Pulverized Coal Boiler Stack
S02	Natural Gas-fired Auxiliary Boiler
S33	Diesel-Fired Emergency Generator
S34	Diesel-Fired Emergency Fire Water Pump
S40	Diesel-Fired Emergency Fire Water Booster Pump

PLOT PLAN

SANDY CREEK ENERGY STATION

RIESEL, MCLENNAN COUNTY, TEXAS

Designed By:	Checked By:	Project No.:	Date:
S. Bhardwaj	C. Harder	015289	2015-5-26