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June 30, 2014

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
2014 JUN 30 PM 4:23
CHIEF CLERKS OFFICE

Ms. Bridget C. Bohac
Chief Clerk
Texas Commission on Environmental Quality
P.O. Box 13087, MC 105
Austin, TX 78711-3087

RE: TCEQ Docket No. 2012-1635-MIS-U; Brazos Electric Power Cooperative, Inc.; Johnson County Generation Facility; CN600128821 I RN100223312; Account No. HI-0230-L; Permit No. 25384/PSD-TX-839; Filing of Appeal for Application for Use Determination for Pollution Control Property Application No. 13544

Dear Ms. Bohac:

Brazos Electric Power Cooperative, Inc. ("BEPC") received a Notice of Negative Use Determination for Application for Use Determination for Pollution Control Property Application No. 13544 from Mr. David Brymer, Director of the Air Quality Division of the Texas Commission on Environmental Quality, dated June 5, 2014 ("Notice of Negative Use Determination"). The Notice of Negative Use Determination was sent to BEPC's tax consultant, Mr. Jim Harris, with insufficient postage. As a result, Mr. Harris did not receive the Notice of Negative Use Determination until June 13, 2014, upon his payment to the United States Postal Service of the additional $0.21 that was required for proper delivery. In an abundance of caution, BEPC is utilizing the presumed three business day delivery period set forth in 30 Tex. Admin. Code § 17.25(b) to establish the date of BEPC's date of receipt of the Notice of Negative Use Determination. As such, this appeal of the Negative Use Determination is timely filed.

The following information is provided, as required in 30 Tex. Admin. Code § 17.25(b)(1-5), in support of BEPC's appeal:

1. **Name, address, and daytime telephone number of person filing appeal:**

Paul C. Sarahan
Counsel for Brazos Electric Power Cooperative, Inc.
Thompson & Knight LLP
98 San Jacinto Blvd., Ste. 1900
Austin, Texas 78701
Day Time Phone#: (512) 469-6106

2. **Name and address of the entity to which the use determination was issued:**

Brazos Electric Power Cooperative, Inc.
Johnson County Generation Facility
831 Sparks Dr.
Cleburne, Texas 76033-7700

3. **Use determination application number for the application for which the use determination was issued:**

Use Determination Application No. 13544 ("Application No. 13544")

4. **Request on appeal:**

BEPC respectfully requests the Commission's consideration of the use determination issued on June 5, 2014. Specifically, BEPC requests that the Commission remand this matter to the Executive Director with the following instructions:

A. The Executive Director's inputs that were required to be used in TCEQ's CAP formula are contrary to Tex. Tax Code § 11.31(b);

B. HRSGs have been statutorily designated as pollution control equipment. As such, some portion of the value of that equipment must be attributed to pollution control, and provided a tax exemption;

C. The purpose of the calculation is to determine what percentage of the equipment's value is attributable to production and what percentage is attributable to pollution control. The percentages must add up to 100%;

D. Because the CAP formula is capable of generating a negative number, and in the case at hand, a significantly negative number, it is inconsistent with state law, and invalid as a matter of law;

E. The Executive Director is required to initiate rulemaking to revise the calculation utilized to determine the percentage of the equipment's value that is attributable to production and the percentage of the equipment's value is attributable to pollution control. In doing so, the percentages for the two calculations shall add up to 100% and neither calculation shall result in a negative number;

F. With respect to the pending application, the Executive Director shall grant a positive use determination of 64.29% for the equipment claimed in BEPC's Application No.

13544, as originally filed on or about April 24, 2009, as amended on March 7, 2012,[1] and as reflected in its responses to the Executive Director filed in this matter.

5. **Basis for the Appeal:**

BEPC respectfully requests that the Commission consider the Executive Director's use determination based specifically on the single issue that forms the basis of the Negative Use Determination issued in this matter on June 5, 2014, and based on that consideration, remand this matter to the Executive Director for further actions, as set forth above. In support of this request, BEPC would show as follows:

A. The Executive Director Relies on a Single Basis for His Negative Use Determination with respect to BEPC's Application No. 13544

The Executive Director bases his Negative Use Determination issued in this matter solely on his finding that BEPC's methods for determining the use determination are unreasonable. No other issue was presented by the Executive Director in the Negative Use Determination, and under due process considerations, the Executive Director is barred from raising any additional issue(s) in support of a Negative Use Determination in this matter in any response to this appeal.

For purposes of establishing the record before the Commission, BEPC understands that the prior filings under this Docket No. 2012-1635-MIS-U are before the Commission and BEPC is not required to refile these documents in order for them to be considered a part of the Commission's record. To complete the record, BEPC has attached to this Appeal BEPC's Application No. 13544; the Executive Director's Notice of Deficiency, dated February 21, 2013; BEPC's Response, dated June 24, 2013; the Executive Director's Second Notice of Deficiency, dated February 3, 2014; BEPC's Response, dated April 4, 2014; and the Executive Director's Negative Use Determination, dated June 5, 2014. These documents are attached hereto as Attachments A-F, respectively, and are incorporated herein.[2]

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[1] The Negative Use Determination refers to Application No. 13544 as having been filed as a Tier IV application. As originally filed, that is correct. However, based on certain decisions of the Commission, BEPC filed an amended Application No. 13544, under Tier III, on March 7, 2012.

[2] Further, the argument and evidence presented by those similarly situated HRSG applicants is incorporated herein by reference as if fully set forth herein including, without limitation, the argument and evidence presented in relation to Application Nos. UD 07-11914 (Tenaska Gateway Partners, Ltd- Rusk County); UD 07-11966 (Freestone Power Generation, L.P. –Freestone County); UD 07-11971 (Borger Energy Associates, L.P.- Hutchinson County); UD 07-11969 (Brazos Valley Energy, L.P.- Fort Bend County); UD 07-11994 (Freeport Energy Center, L.P.- Brazoria County); UD 07-11926 (CER-Colorado Bend Energy LLC (f/k/a Navasota Wharton Energy Partners, L.P .) - Wharton County); UD 12696 (EN Service's LP- Harrison County); UD 16409 (Bosque Power Company, LLC- Bosque County); UD 12210 & 12211 (Topaz Power Group, LLC- Nueces County); UD 15506, 16410, 16411 & 16412 (Cottonwood Energy Company LP - Newton County); UD 12268 (WolfHollow I, LP- Hood County); UD 13534 (South Texas Electric Cooperative, Inc. –Victoria County); UD 16413 (Brazos Electric Cooperative, Inc.- Jack County); UD 12004 (NRG Texas Power LLC- Limestone County); UD 07-12271 (Midlothian Energy Limited Partnership – Ellis County); UD 07-12202 (Wise County Power Company, LLC- Wise County); UD 07-12203

B. Calculation of Pollution Control Percentage

Following the Commission's remand of the Executive Director's prior negative use determination related to BEPC's Application No. 13544, the Executive Director mandated the use of particular inputs to the cost analysis procedure ("CAP") formula set forth in 30 Tex. Admin. Code §17.17(c). BEPC objected to these mandated inputs for reasons set forth below, but, without waiving such objections, provided the requested calculation in two responses filed with the Executive Director. In addition, BEPC provided four alternative approaches to calculating the percentage of the equipment's value that is attributable to production and the percentage that is attributable to pollution control.

By statute, TCEQ is charged with adopting rules that "allow for determinations that distinguish the proportion of property that is used to control, monitor, prevent, or reduce pollution from the proportion of property that is used to produce good or services." TEX. TAX CODE §11.31(g)(3). "Proportion" is commonly defined as "a part considered in relation to the whole." AMER. HERITAGE COLLEGE DICT. at 1117 (4th ed., 2004). The Legislature has designated HRSGs as pollution control property. TEX. TAX CODE §11.31(k)(8). BEPC has conceded that HRSGs have both pollution control and production purposes. To effectuate the Legislature's direction as established in Tex. Tax Code §11.31(g)(3), TCEQ is charged with developing a calculation that will determine the proportion of property that is used to control, monitor, prevent, or reduce pollution and the proportion of property that is used to produce good or services. The two portions form the whole, and therefore the two percentages must add up to 100%. Utilizing the Executive Director's mandated inputs, TCEQ's CAP procedure fails this test. Because the CAP procedure formula, as interpreted by the Executive Director, generates a negative number, it is inconsistent with state law, and invalid as a matter of law. Given this outcome, BEPC respectfully requests that the Commission remand this matter to the Executive Director with specific instructions consistent with the Legislature mandate that HRSGs constitute pollution control equipment.

(1) The Executive Director's Mandated Inputs are Contrary to Tex. Tax Code § 11.31(b)

In his February 21, 2013 Notice of Technical Deficiency, the Executive Director required that BEPC calculate a partial use determination using specific inputs for the variables set forth in the CAP. BEPC objected and continues to object to the mandated inputs, as this action constitutes improper and illegal rulemaking. Without waiving that objection, BEPC provided the requested calculation, which resulted in a partial use determination of -605.08%. Based on further direction from the Executive Director set forth in his February 3, 2014 Second Notice of Technical Deficiency, BEPC revised the calculation as directed, which resulted in a partial use determination of -82.55%.

(Ennis Power Company, LLC- Ellis County); UD 15020 (Motiva Enterprises, LLC- Jefferson County); UD 07-12272 (Hay Energy Limited Partnership- Hays County); and UD 12826 (GIM Channelview Cogeneration LLC- Harris County).

The Executive Director mandated that a boiler is the comparable appropriate equipment for the CCO input in the CAP formula calculation. By doing so, the Executive Director erred in three ways.

First, the HRSG is not solely production equipment. As the Executive Director well knows and as the Legislature has expressly recognized, the HRSG serves two functions: (1) it allows BEPC to reuse heat to generate steam and thereby generate more electricity; and (2) by doing so, it reduces the amount of energy needed to generate the increased amount of electricity and, as a result, prevents pollution that would occur in the absence of the HRSG. The Legislature has recognized that the HRSG is pollution control equipment. The Executive Director and the Commission, through rulemaking, have also recognized this fact.

Second, BEPC has never contended that the HRSG was installed solely for the purpose of preventing pollution. The process in which BEPC and the Executive Director are currently engaged is to determine the allocation of the HRSG's two functions, i.e., what percentage is attributable to production and what percentage is attributable to pollution prevention. A resulting consequence is that the two percentages must add up to 100%. As noted herein, and in BEPC's previous submissions, the Executive Director's use and interpretation of the CAP formula does not meet this test.

Third, by fiat, the Executive Director has determined that a boiler sized to create the same amount of steam as the HRSG is *the*, i.e., the one and only, appropriate comparable equipment that may be used in a CAP calculation for a HRSG. The Executive Director has exceeded his authority by mandating one and only one approach to this variable, and further, in that regard, mandating the consideration of quite possibly the most expensive equipment possible. "Comparable equipment" is not a defined term in 30 Tex. Admin. Code ch. 17. "Comparable" is defined in normal usage as similar, or capable of comparison. Synonyms include "analogous," "corresponding," "matching," and "resembling." BEPC asserts that replacement boilers do not match or resemble a HRSG, and therefore the Executive Director's mandate is improper.

Further, even if replacement boilers were analogous to a HRSG, it cannot be argued that replacement boilers are the only comparable equipment. If a CCO must be used, BEPC asserts that an appropriate comparable equipment is a pipe that would vent heat in the absence of the HRSGs. This approach is discussed in further detail below.

In his February 3, 2014 Notice of Technical Deficiency, the Executive Director directed that BEPC remove certain equipment, specifically the feedwater systems; boiler systems; chemical injection; cooling air systems; nitrogen systems; and condensate systems be removed from each of the three CAP-based calculations. In addition, the Executive Director required that BEPC remove from the calculation of Production Costs, in each of the three CAP-based calculations, any costs related to operating the gas turbine, the water systems, or the steam turbine. The Executive Director acknowledged that his initial refusal to include costs related to

the operation of the duct burners, including fuel costs, was in error, and he requested that these costs be included in the calculation of Production Costs.

The Executive Director contended that the feedwater systems, boiler systems, chemical injection, cooling air systems, nitrogen systems, and condensate systems are all production equipment for which a positive use determination is not available. However, these systems are essential to the operation of the HRSG. Without these pieces of equipment, the HRSG will not function and neither the production nor the pollution prevention benefits will be achieved. The HRSG must include all ancillary equipment and production costs required for the equipment to operate. The HRSG does not function without the heat generated from fuel burned by a combustion turbine ("CT"), nor will it function without water to make steam. In order for water to be introduced to the HRSG, the following equipment must be present: the feed water system, cooling air systems, condensate systems, and chemical injection systems. The production costs essential for HRSG to operate, and produce the required megawatts ("MW") demanded by the grid, must include CT fuel consumption, duct burner fuel consumption, and Steam Turbine production costs. In order for the HRSG to produce the MW required to supply the grid with the load required by ERCOT while limiting the total emissions produced, as required by applicable environmental regulations, HRSG must function as designed. This design includes the feed water system, cooling air systems, condensate systems, and chemical injection systems. The allocation of the production and pollution prevention functions of the equipment serves to appropriately identify the proportion of the equipment costs for which a tax abatement may be obtained.

Without the operation of these units, and their associated expenses (including fuel costs), no electricity would be generated from any steam produced via the HRSG, and therefore no marketable product would be generated. The Executive Director cannot have it both ways. If electricity is the marketable product, the HRSG Applicants must be allowed to take into account the costs (and the equipment) associated with generating that marketable product as part of its NPVMP calculation. TCEQ's rules mandate it.

The Executive Director, through the processing of this application, also narrowed the scope of the CAP's Production Cost variable by asserting that the cost attributed to the production of electricity, which the Executive Director has designated as the marketable product, must exclude costs relating to operating the gas turbine or the steam turbine including fuel costs.

The exclusion of fuel costs from Production Cost is particularly problematic and inappropriate. "Production Cost" expressly includes the cost of "raw materials." *See* 30 TEX. ADMIN. CODE §17.17(c)(2). In this context, fuel is the raw material for the production of the steam and its costs are an element of Production Cost, by definition. Additional costs that are included in Production Cost include storage, transportation, and personnel costs. *See id.* The interpretation of the elements to be included in, and excluded from, the calculation of NPVMP is inaccurate and constitutes improper and illegal rulemaking.

Without waiving its objections to the Executive Director's directives included in the Notices of Technical Deficiency, as set forth above, and in prior proceedings and filings in this matter, BEPC has prepared revised calculations in conformance with these directives. These calculations were prepared for purposes of responding to the Notices of Technical Deficiency lest the Executive Director find that BEPC had failed to submit a complete application and therefore determine that its application is void. BEPC expressly reserved its right to contest the Executive Director's directives, which it does through this appeal. Under the Executive Director's mandated approach, the use determination calculation is -82.55%.

It is BEPC's conclusion that the calculation, using the specific inputs mandated by the Executive Director, will in each and every case result in a negative use determination, based on a CAP calculation that will be significantly negative. Such a result is no more appropriate than a situation in which a calculation consistently results in a use determination of greater than 100%. This result is contrary to the Legislature's enactment of Tex. Tax Code § 11.31(b).

HRSGs have been statutorily designated as pollution control equipment. As such, some portion of the value of that equipment must be attributed to pollution control, and provided a tax exemption. A result of zero, less than zero, or far less than zero is not valid, any more than a result of greater than 100% would be valid. The purpose of the calculation is to determine what percentage of the equipment's value is attributable to production and what percentage is attributable to pollution prevention. The percentages must add up to 100%.

Because the formula, as interpreted by the Executive Director, is capable of generating a negative number, it is inconsistent with state law, and invalid as a matter of law. Given this outcome, BEPC respectfully requests that the Commission remand this matter to the Executive Director with specific instructions consistent with the Legislature mandate that HRSGs constitute pollution control property.

(2) Alternative Calculations Consistent with the Legislature's Designation of HRSGs as Pollution Control Property

In an effort to reach a resolution of this matter, and without waiving its rights to pursue a partial use determination of 64.29%, BEPC proposed four other calculations for the Executive Director's consideration. Two involved approaches that did not follow the CAP formula, specifically: (i) The Executive Director's 2008 Adopted Recommendation, which proposed an across-the-board 61% positive use determination for HRSG applicants; and (ii) a five-step Avoided NOx Emissions calculation that would result in a 39.7% positive use determination. The final two calculations utilized the CAP formula with inputs for the variables that were consistent with the CAP formula, but which differed from the inputs mandated by the Executive Director. BEPC asserts that these approaches constitute a more reasoned calculation of a positive use determination given the flaws identified in the CAP formula, as interpreted by the Executive Director. Each approach is addressed below:

a) The Executive Director's 2008 Adopted Recommendation

On December 3, 2008, the Executive Director affirmatively represented to the Commission that, "The Executive Director *intends to apply the adopted recommendation to all subsequently filed similar use determination applications, and to those applications currently pending adjudication.*" Executive Director's December 3, 2008 Response Brief to Rusk County, et al., Appraisal Districts' Appeals of the Executive Director's Use Determinations, § IV, pp. 10-11 (emphasis added). That recommendation was based, among other things, on the Work Group's efforts and reads as follows:

> The thermal efficiency increase or production gain derived from the installation of a HRSG is approximately 39%. Since this percentage represents the additional amount of electrical energy produced for a given heat input, it therefore represents the production value of the equipment. Based on this production value, the pollution control percentage of a HRSG installed at a combined-cycle facility is 61%. *Staff is therefore recommending the positive use determination of 61% for the installation of a HRSG in a combined-cycle facility.*

Id. at 11 (emphasis in original).

In his Negative Use Determination, the Executive Director rejected the proposed use of the Executive Director's 2008 Adopted Recommendation because it "did not accurately calculate an appropriate use determination because the less efficient the equipment, the higher the positive use determination it yielded." Negative Use Determination, at 2. Through this analysis, the Executive Director erred in two ways.

First, given that the percentage would be applied across-the-board to all HRSG applicants, the percentage appears to have been intended to represent the average pollution control proportion attributable to the installation of a HRSG in a combined-cycle facility. Because the percentage would be applied to all HRSG applicants, no advantage would be gained as a result of inefficiency at a particular facility.

Second, the deficiency that the Executive Director's claims to exist in the Executive Director's 2008 Adopted Recommendation is also present in the Executive Director's interpretation of the CAP formula. Specifically, the Executive Director has asserted that electricity is the marketable product for which BEPC must calculate a net present value as part of the CAP formula. The more efficient a facility is, the more electricity it will produce over the life of the facility. The more electricity the facility produces over its life, the greater the net present value of that stream of electricity will be. Because the net present value is a deduction in the numerator of the CAP formula, a more efficient plant will generate a higher net present value, and therefore a lower use determination percentage under the CAP procedure. Using the Executive Director's reasoning, if the Executive Director's 2008 Adopted Recommendation produces an unreasonable result and should not be used as a basis for a final use determination

because it rewards inefficiency and punishes efficiency, then neither should the CAP formula, as interpreted by the Executive Director, because it has the same effect.

b) Avoided Emissions Approach

The CAP formula focuses on the productivity aspects of a piece of equipment, rather than on the pollution control benefits derived from the use of that equipment. BEPC respectfully suggests that the calculation should be focused on the HRSG's pollution control benefits. One approach to doing so would be to calculate the amount of NO_x emissions that are avoided by the use of the HRSG.

Step 1 of this approach converts the input-based emissions (those calculated based on the input to the process, specifically lb/MMBtu, the format reported to several agencies) to an output-based format (specifically lb/MWh) using BEPC's heat rate (Btu/kW).

Step 2 multiplies this output-based emission rate by BEPC's capacity and annual capacity factor (a measure of actual plant output compared to the maximum) to calculate annual emissions.

Step 3 and 4 mirror Steps 1 and 2 but are performed for a "Baseline" simple cycle plant using BEPC's heat rate for a six-unit simple cycle facility.

Step 4 uses BEPC's capacity and capacity factor to calculate the Baseline facility's emissions on an equal basis to BEPC.

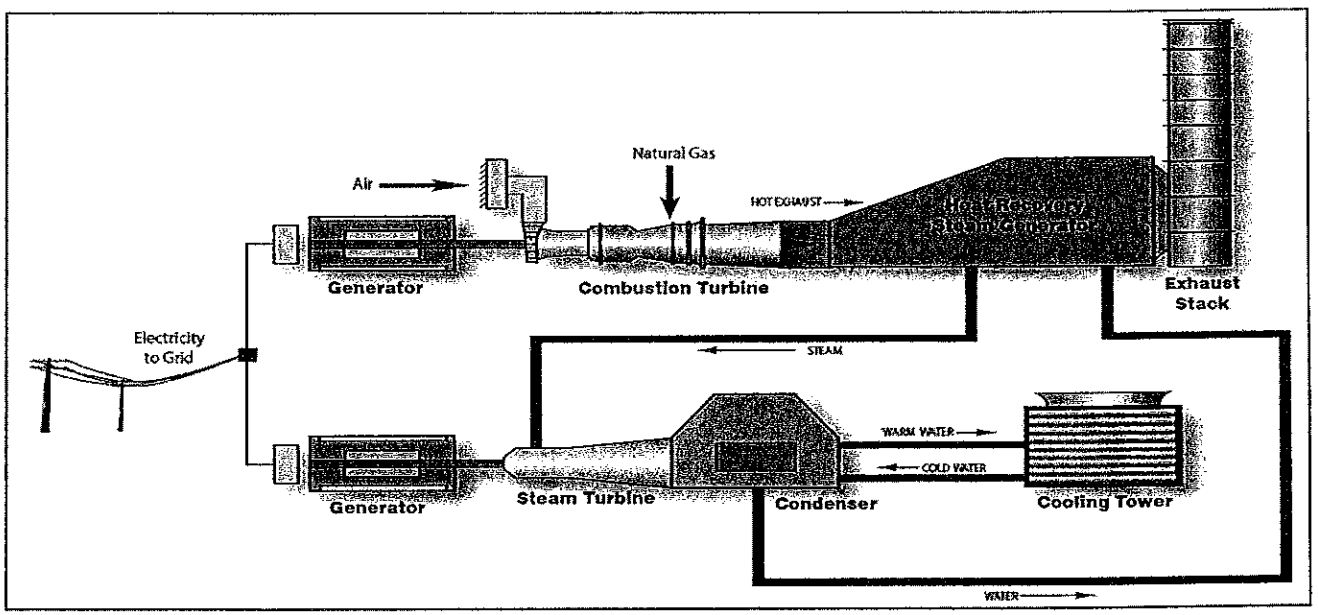
Finally, Step 5 calculates the difference in emissions of BEPC's facility and the Baseline facility and then divides by the lower BEPC emissions to arrive at the avoided emissions calculation. For this application, BEPC's avoided emissions percentage was 39.7%.

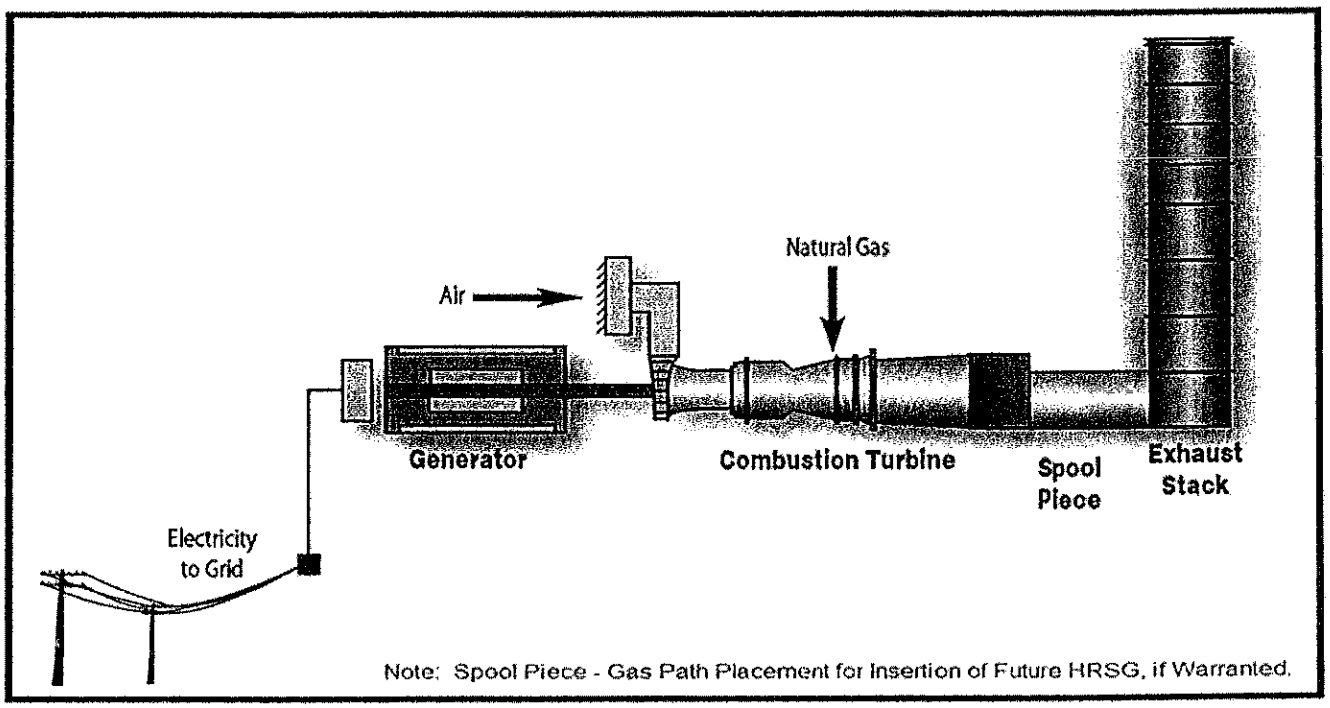
The Executive Director rejected this approach by asserting that it did not distinguish between pollution control and production, and does not attribute any value to production. This is incorrect. The avoided emissions percentage is the pollution control percentage. The production percentage is calculated by subtracting the avoided emissions percentage from 1, resulting in this case in a production percentage of 60.3%.

The Executive Director further contends that this approach ignores NO_x reductions from other property for which a positive use determination has been issued. Such a hypothetical would only apply to equipment that also had the dual pollution control and production functions present in the HRSG scenario. If such a hypothetical presented itself, the Executive Director may be required to conduct further analysis to ensure that the use determination was properly allocated among the various equipment. This hypothetical complication is, however, not a basis for completely rejecting the suggested approach.

c) CAP Calculation Using Piping or Spool Piece

BEPC proposed piping or spool piece as "comparable equipment" that could be used to calculate the Capital Cost Old ("CCO") in the CAP formula. The HRSG and its ancillary equipment hypothetically take the place of the piping or spool piece. The two designs are depicted below:





Using this approach, the application of the CAP formula results in a positive use determination of 63.76%. As stated in BEPC's responses to the Executive Director, without the HRSG, exhaust gases would be conveyed via piping from the combustion chamber to a control device or stack. No additional power would be generated, and no pollution prevention would be achieved. With the use of the HRSG, both objectives are realized.

The Executive Director notes that CCO is the cost of comparable equipment without the pollution control feature. Negative Use Determination, at 2; *see also* 30 TEX. ADMIN. CODE §17.17(c)(1) and its associated Figure. The Executive Director has apparently rejected the piping as the CCO because it produces no steam. Through this analysis, the Executive Director erred in four ways.

First, the rule does not require that the proposed CCO have the same productive capacity as, in this, the HRSG. It simply must be comparable equipment. "Comparable" is not defined in the rules. "Comparable" is defined in normal usage as similar, or capable of comparison. Synonyms include "analogous," "corresponding," "matching," and "resembling." BEPC asserts that replacement boilers do not match or resemble a HRSG, and therefore the Executive Director's mandate is improper.

Second, with respect to the "comparable equipment" variable, the Executive Director has exceeded his authority by mandating one and only one approach to this variable. Further, the Executive Director has mandated the consideration of quite possibly the most expensive equipment possible as CCO. The Executive Director's mandate constitutes improper rulemaking.

Third, the use of the CCO, as interpreted by the Executive Director, simply makes the HRSG twice as expensive - first, the entity must purchase the HRSG, then it must discount the value of the HRSG by the cost of hypothetical equipment designed to mimic the productivity of the HRSG itself. Such an approach negates the purpose of installing the HRSG in the first place, i.e., producing greater quantities of steam while reducing the environmental impact that would occur without the use of this equipment.

Fourth, the mandate of a boiler(s) as CCO results in a consideration of the production benefits of the HRSG twice, once by determining the size and cost of the boiler required to be considered as CCO, and again in the calculation of the net present value of the electricity that the Executive Director has deemed to be the marketable product for the HRSG. This is, again, improper. NPVMP is designed to capture "the production benefits of property used partially for pollution control and partially for production." *See* 35 Tex. Reg. 10964, 10965 (Dec. 10, 2010). Because the CCO and CCN have been equalized or normalized, the HRSG is no longer producing additional steam beyond that produced by CCO. Therefore, there is no basis for NPVMP under such circumstances.

Under BEPC's approach, the HRSG "replaces" the piping or spool piece that allows the steam generated by the combustion turbine to be directed to an exhaust stack where the steam is emitted. The metal piping is replaced by the metal HRSG which is designed to reutilize the steam and generate additional steam, achieving pollution control and production benefits. The piping is equipment that is comparable to the HRSG in that both are metal pieces of equipment that serve as conduits for steam. The piping does not have the pollution control feature present with the HRSG, and thus meets the definition of CCO. Granted, the piping does not have productive value, but the definition of CCO does not require it to have productive value. The productive value generated from the use of the HRSG is addressed in the CAP formula through the calculation of the net present value of the additional electricity produced by virtue of the HRSG over its lifetime.

d) CAP Calculation with CCO as 0

Finally, in this regard, BEPC proposed using zero as the CCO and NPVMP variables. Using these inputs for the designated variables, BEPC's HRSG would be entitled to a 100% positive use determination. As set forth above, BEPC asserts that replacement boilers do not match or resemble a HRSG, and therefore the Executive Director's mandate is improper. Indeed, an application of TCEQ's hierarchical definition of "Capital Cost Old," found in 30 Tex. Admin. Code § 17.17(c)(1), note 3, will conclude that no CCO should be used in the CAP calculation for a HRSG.

The Executive Director, in his February 21, 2013 Notice of Deficiency, directed the HRSG Applicants to calculate the Production Capacity Factor ("PCF") "by dividing the capacity of the existing equipment or process by the capacity of the new equipment or process." This calculation accurately reflects the first portion of the TCEQ's rules, found in 30 Tex. Admin. Code §17.17(b). However, the Executive Director failed to acknowledge that, under 30 Tex. Admin. Code §17.17(b), the PCF is to be included in the CAP formula only in limited circumstances. The rule notes, "when there is an increase in production capacity, PCF is used to adjust the capacity of the new equipment or process to the capacity of the existing equipment or process. When there is a decrease in production capacity, PCF is used to adjust the capacity of the existing equipment or process to the production capacity of the new equipment or process. In this case, this calculation is modified so that PCF is applied to Capital Cost Old (CCO) rather than Capital Cost New." *Id.*

First, there is no existing equipment or process. As a result, there is no increase or decrease in capacity. Under such circumstances, the rule recognizes that no calculation of PCF should be made. As a result, that portion of the CAP calculation is to be omitted. Inserting a value in for CCO requires that there be "old equipment." As stated, this is not a replacement of an HRSG. There is no old equipment.

Second, the Executive Director directed BEPC to calculate CCO as the cost of a boiler(s) required to produce the same amount of steam produced by the HRSG. The Executive Director's

interpretation of CCO is contrary to TCEQ's rules, which define "Capital cost old" as "The cost of the equipment that is being or has been replaced by the equipment covered in an application." 30 TEX. ADMIN. CODE §17.2(2). The definition continues by directing that the calculation of this variable in the CAP procedure is to be performed using one of the four hierarchical methods set forth in 30 Tex. Admin. Code §17.17(b)(1).[3]

The hierarchical methods, with an analysis of their applicability, are as follows:

Method 3.1: If comparable equipment without the pollution control feature is on the market in the United States, then an average market price of the most recent generation of technology must be used.

Analysis: There is no equipment that serves the function of the HRSG without its pollution control feature. The HRSG is the equipment that is the subject of the use determination application. There is no substitute for this equipment. Method 3.1 is therefore inapplicable.

Method 3.2: If the conditions in variable 3.1 do not apply and the company is replacing an existing unit that already has received a positive use determination, the company shall use the CCO from the a location for the previous use determination.

Analysis: The company is not replacing an existing unit that already has received a positive use determination. Method 3.2 is therefore inapplicable.

Method 3.3: If the conditions in variable 3.1 and 3.2 do not apply and the company is replacing an existing unit, then the company shall convert the original cost of the unit to today's dollars by using a published industry specific standard. If the production capacity of the new equipment or process is lower than the production capacity of the old equipment or process CCO is divided by the PCF to adjust CCO to reflect the same capacity as CCN.

Analysis: The company is not replacing an existing unit. Method 3.3 is therefore inapplicable.

Method 3.4: If the conditions in variables 3.1, 3.2, and 3.3 do not apply, and the company can obtain an estimate of the cost to manufacture the alternative equipment without the pollution control feature, then an average estimated cost to manufacture the unit must be used. The comparable unit must be the most recent generation of technology. A copy of the estimate must be provided with the worksheet including the specific source of the information.

Analysis: With the exception of the piping or spool piece discussed in the approach above, there is no alternative equipment that could be manufactured to serve the function of the HRSG without its pollution control feature. The HRSG is the equipment that is the subject of the

[3] It appears that this reference should be to 30 Tex. Admin. Code § 17.17(c)(1).

use determination application. There is no substitute for this equipment. Method 3.4 is therefore inapplicable.

As applied, unless TCEQ relies on the cost of the piping or spool piece, TCEQ's hierarchical methods are not applicable. Therefore, for purposes of this Application and its CAP calculation, CCO is zero. The mandate of "comparable equipment" that is, in fact, not comparable as hypothetical "replaced" equipment is inappropriate and constitutes improper and illegal rulemaking. On the basis of this objection, BEPC respectfully requests that the Executive Director determine that there be no CCO for CAP calculations related to HRSGs or, in the alternative, that the hypothetical "replaced" equipment be considered to be the piping reflected as "Spool Piece" in the diagram set forth above.

C. Request for Specific Instructions with Remand

As the Commission knows, the pending HRSG applications for which the Executive Director recently issued negative use determinations were filed years ago. BEPC's Application No. 13544 was originally filed on or about April 24, 2009, and amended on March 7, 2012. After years of inaction on the HRSG use determination issue, the Executive Director issued his first negative use determination to BEPC in June 2012. After the filing of appeals and associated briefing, the Commission heard argument from the parties in December 2012 and remanded the applications to the Executive Director for further review.

On February 21, 2013, the Executive Director issued his first Notice of Deficiency following the remand. Responses were timely filed on June 24, 2013. On February 3, 2014, the Executive Director issued a Second Notice of Deficiency to BEPC. BEPC timely filed its response on April 4, 2014. The Executive Director issued its second negative use determination with respect to Application No. 13544 on June 5, 2014.

The substance of the Executive Director's objections to BEPC's application are identical to those reflected in the June 2012 negative use determination. Despite hours of work on the part of the Executive Director's staff and the HRSG applicants, and the production of reams of information by the HRSG applicants to the Executive Director for his consideration, we stand in the same place that we were in two years ago. The HRSG applicants and their respective appraisal districts have no certainty with respect to how this matter will be resolved.

It is for this reason that BEPC respectfully requests more than a simple remand of this matter to the Executive Director. BEPC fears that such an action would result solely in more delay and more uncertainty. Instead, BEPC respectfully requests that the Commission remand this matter to the Executive Director with the following instructions:

1. The Executive Director's inputs that were required to be used in TCEQ's CAP formula are contrary to Tex. Tax Code § 11.31(b);

2. HRSGs have been statutorily designated as pollution control equipment. As such, some portion of the value of that equipment must be attributed to pollution control, and provided a tax exemption;

3. The purpose of the calculation is to determine what percentage of the equipment's value is attributable to production and what percentage is attributable to pollution control. The percentages must add up to 100%;

4. Because the CAP formula is capable of generating a negative number, and in the case at hand, a significantly negative number, it is inconsistent with state law, and invalid as a matter of law;

5. The Executive Director is required to initiate rulemaking to revise the calculation utilized to determine the percentage of the equipment's value that is attributable to production and the percentage of the equipment's value is attributable to pollution control. In doing so, the percentages for the two calculations shall add up to 100% and neither calculation shall result in a negative number;

6. With respect to the pending application, the Executive Director shall grant a positive use determination of 64.29% for the equipment claimed in BEPC's Application No. 13544, as originally filed on or about April 24, 2009, and amended on March 7, 2012, and as reflected in its responses to the Executive Director filed in this matter.

D. Conclusion

Based on the foregoing, BEPC respectfully requests that the Commission consider the negative use determination issued by TCEQ Executive Director with respect to BEPC's application and that, following such consideration, the Commission remand the matter to the Executive Director with the instructions set forth above.

In addition, given the short time allowed for providing this response to the negative use determination, BEPC respectfully requests the opportunity to supplement this filing with any additional materials that may be relevant to the Commission's consideration of the appeal. It is BEPC's understanding that it will have an opportunity to reply to any response that may be filed by the Executive Director or the tax appraisal district.

Sincerely,

Paul C. Sarahan

PS/cb
Enclosure

Cc: Mr. Ronald Hatlett, TCEQ, Tax Relief for Pollution Control Property (Receiving 1 of 7 filed copies via the Chief Clerk)

Chief Appraiser, Johnson County Appraisal District, 109 N. Main St., Cleburne, TX 76033-4941

Tax Relief for Pollution Control Property

Application Form – Effective January 2008

DRAFT

TCEQ-00611 (Revised January 2008)

DISCLAIMER

This document is intended to assist persons in applying for a use determination, pursuant to Title 30 Texas Administrative Code Chapter 17 (30 TAC 17). Conformance with these guidelines is expected to result in applications that meet the regulatory standards required by the Texas Commission on Environmental Quality (TCEQ). However, the TCEQ will not in all cases limit its approval of applications to those that correspond with the guidelines in this document. These guidelines are not regulation and should not be used as such. Personnel should exercise discretion in using this guidelines document. It should be used along with other relevant information when developing an application.

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
APPLICATION FOR USE DETERMINATION
FOR POLLUTION CONTROL PROPERTY

The TCEQ has the responsibility to determine whether a property is a pollution control property. A person seeking a use determination must complete the attached application or a copy or similar reproduction. For assistance in completing this form refer to the TCEQ guidelines document, *Property Tax Exemptions for Pollution Control Property,* as well as 30 TAC §17, rules governing this program. For additional assistance please contact the Tax Relief for Pollution Control Property Program at (512) 239-3100. The application should be completed and mailed, along with a complete copy and the appropriate fee, to: TCEQ MC-214, Cashiers Office, PO Box 13088, Austin, Texas 78711-3088.

Information must be provided for each field unless otherwise noted.

1. GENERAL INFORMATION

A. What is the type of ownership of this facility?

- ☒ Corporation
- ☐ Partnership
- ☐ Limited Partnership
- ☐ Sole Proprietor
- ☒ Utility
- ☐ Other:

B. Size of company: Number of Employees

- ☐ 1 to 99
- ☒ 100 to 499
- ☐ 500 to 999
- ☐ 1,000 to 1,999
- ☐ 2,000 to 4,999
- ☐ 5,000 or more

C. Business Description: (Provide a brief description of the type of business or activity at the facility)

Generation and Transmission of electric energy to member Distribution Cooperatives.

2. TYPE OF APPLICATION

- ☐ **Tier I** $150 Fee
- ☐ **Tier II** $1,000 Fee
- ☐ **Tier III** $2,500 Fee
- ☒ **Tier IV** $500 Fee

NOTE: Enclose a check, money order to the TCEQ, or a copy of the ePay receipt along with the application to cover the required fee.

3. NAME OF APPLICANT

A. Company Name: Brazos Electric Power Cooperative, Inc.
B. Mailing Address (Street or P.O. Box): P.O. Box 2585
C. City, State, and Zip: Waco, Texas 76702-2585

4. PHYSICAL LOCATION OF PROPERTY REQUESTING A TAX EXEMPTION

A. Name of Facility or Unit: Johnson County Generation Facility
B. Type of Mfg. Process or Service: Electric Power Plant
C. Street Address: 831 Sparks Drive
D. City, State, and Zip: Cleburne, Texas 76033
E. Tracking Number (*Optional*):
F. Company or Registration Number *(Optional)*:

5. APPRAISAL DISTRICT WITH TAXING AUTHORITY OVER PROPERTY

A. Name of Appraisal District: Johnson County
B. Appraisal District Account Number:

6. CONTACT NAME

A. Company/Organization Name	H&H Associates
B. Name of Individual to Contact:	J.M. Harris
C. Mailing Address (Street or P.O. Box):	406 FM 3016
D. City, State, and Zip:	Grapeland, Texas 75844
E. Telephone number and fax number:	(936) 687-4230 (936) 687-9064
F. E-Mail address (if available):	jimharrisat-h-h@hughes.net

7. **RELEVANT RULE, REGULATION, OR STATUTORY PROVISION**
For each media, please list the specific environmental rule or regulation that is met or exceeded by the installation of this property.

MEDIUM	Rule/Regulation/Law
Air	40 CFR PART 60; 30 TAC 116.110; 30 TAC 116.911; 30 TAC 117.131
Water	
Waste	

8. **DESCRIPTION OF PROPERTY (Complete for all applications)**
Describe the property and how it will be used at your facility. **Do not simply repeat the description from the Equipment & Categories List.** Include sketches of the equipment and flow diagrams of the processes where appropriate. Use additional sheets, if necessary.

The Ponderosa Pine Generation Plant was commissioned in 1997. The Plant is a 258 MW gas-fueled, combined-cycle electric generating station. The Plant is made up of a 154 MW combustion turbine coupled with a 104 MW steam turbine by way of a heat recovery steam generator (HRSG). The Plant experienced a catastrophic explosion in May of 2005 in which the HRSG was destroyed. Brazos Electric Power Cooperative, Inc. acquired the disabled Plant in late 2005 and commenced reconstruction. Cost to reconstruct the HRSG, excluding demolition, was $28,599,376 of which $487,390 is Tier I equipment which previously received a 100% exemption by way of Use Determination Application 06-10507, leaving a cost of $28,111,986 to be dealt with by this application. The Plant became operational in September of 2006.

A combined cycle facility consists of one or more gas and steam turbines. The air expansion that occurs during the combustion process turns the gas turbine that drives the generator to produce electricity. The combustion in the gas turbine also produces a hot exhaust gas. In a combined cycle unit the heat produced during the combustion of natural gas is directed to the HRSG to generate steam used to turn a steam turbine. Therefore, both the gas and steam turbines generate electricity, improving thermal cycle efficiency from approximately 36% to approximately 55%. This allows more electrical energy to be produced for a given heat input than is possible by a simple cycle gas turbine (Brayton cycle) or traditional steam boiler / turbine (Rankin cycle) configuration. Since less fuel is required per kilowatt of power produced, less exhaust gas emissions (NOX, CO, CO2, etc.) are produced. Therefore, the HRSG's primary purpose of capturing and converting waste heat results in meaningful environmental benefits.

Efficiency gain due to HRSG: (55% / 36%) minus 1 = 52.8%

Environmental benefit: (1 minus efficiency gain of 52.8%) = 47.2%

We are mindful that the TCEQ Staff has routinely granted a 100% exemption for the cost of Heat Recovery Steam Generators presumably because they were afforded special mention in HB 3732 enacted in 2007.

Land: If a use determination is being requested for land, provide a legal description and an accurate drawing of the property in question.

_____

9. PARTIAL PERCENTAGE CALCULATION

This section is to be completed for Tier III and IV applications. For information on how to conduct the partial percentage calculation, see the application instructions document. Attach calculation documents to completed application.

10. PROPERTY CATEGORIES AND COSTS

List each control device or system for which a use determination is being sought. Provide additional attachments for more than 3 properties.

Property	Taxable on 1/01/94?	DFC Box	ECL #	Estimated Cost	Use %
Land					
Property Heat Recovery Steam Generator	No	3	B-8	$28,111,986	100
Totals					

11. EMISSION REDUCTION INCENTIVE GRANT

(For more information about these grants, see the Application Instruction document).

Will an application for an Emission Reduction Incentive Grant be filed for this property/project?

☐Yes ☒No

12. APPLICATION DEFICIENCIES

After an initial review of the application, the TCEQ may determine that the information provided with the application is not sufficient to make a use determination. The TCEQ may send a notice of deficiency, requesting additional information that must be provided within 30 days of the written notice.

13. FORMAL REQUEST FOR SIGNATURE

By signing this application, you certify that this information is true to the best of your knowledge and belief.

Name: Clifton B. Karnei Date: 4/21/09

Title: Executive Vice President and General Manager

Company: Brazos Electric Power Cooperative, Inc.

Under Texas Penal Code, Section 37.10, if you make a false statement on this application, you could receive a jail term of up to one year and a fine up to $2,000, or a prison term of two to 10 years and a fine of up to $5,000.

14. DELINQUENT FEE/PENALTY PROTOCOL

This form will not be processed until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ are paid in accordance with the Delinquent Fee and Penalty Protocol. (Effective September 1, 2006)

Brazos Electric Power Cooperative, Inc.
P.O. Box 2585
Waco, Texas 76702-2585

BRAZOS ELECTRIC COOPERATIVE

32-2/1110

Bank of America, N.A.
Dallas, Texas

Check No. 233965

Date	Amount
04/24/09	$******500.00

General Fund

FIVE HUNDRED AND 00/100 **********

Pay TCEQ
To the MC-214, CASHIERS OFFICE
Order P. O. BOX 13088
AUSTIN TX 78711-3088

Clifton B. Karna
Signature

Bonnie D. Robinson
Counter Signature

SIGNATURE AREA CONTAINS A KNIGHT & FINGERPRINT CHECK WORDING
U.S. PATENTS 5538290, 5575508, 5641183, 5765353, 5984364, 6030000

⑈233965⑈ ⑆111000025⑆ 0047704963 98⑈

Check No.: 233965
Check Date: 04/24/09
Payee No.: 26553

Payee: TCEQ

Stub 1 of 1

Invoice Number	Voucher Date	Description	Invoice Amount	Discount	Net Amount
PROPERTY TAX ABATE	042209	JOHNSON COUNTY FACILITY	500.00		500.00
			500.00		500.00

Brazos Electric Power Cooperative, Inc. Waco, Texas Detach and retain for your records

mailed 4/24/09

REORDER 601 • U.S. PATENT NO. 5538290, 5575508, 5641183, 5765353, 5984364, 6030000

Bryan W. Shaw, Ph.D., *Chairman*
Buddy Garcia, *Commissioner*
Carlos Rubinstein, *Commissioner*
Mark R. Vickery, P.G., *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

September 30, 2009

Mr. Jim Harris
H & H Associates
406 FM 3016
Grapeland, TX 75844

Mr. Harris:

This letter is in response to your inquiries, dated August 18, 2009 and September 9 and 15, 2009, regarding Use Determination Application No. 13544. This application, filed on April 27, 2009, requested a 100% positive use determination for a reconstructed Heat Recovery Steam Generator (HRSG). The application was declared administratively complete on May 7, 2009 and placed on hold on May 18, 2009, pending the outcome of six use determination appeals involving HRSGs. As I am sure you are aware, House Bill (HB) 3206 and HB3544 were passed by the 81st Legislature. Both bills contain identical language, amending Tex. Tax Code § 11.31 by adding subsections (g-1) and (n). The bills require that the standards and methods for making use determinations apply uniformly to all applications, including applications for equipment listed on Part B of the Equipment and Categories List. The bills also require that the Texas Commission on Environmental Quality (TCEQ or Commission) establish a permanent advisory committee to advise the Commission on the implementation of Tex. Tax Code § 11.31.

HB3206 and HB3544 apply to all applications which were filed on or after January 1, 2009 that are not final as of September 1, 2009. Your application meets these requirements; and as such, its review will be affected by any guidance provided by the Tax Relief for Pollution Control Property Advisory Committee and any subsequent rulemaking implementing HB3206 and HB3544. The Commission is currently empanelling the advisory committee. As a stakeholder in the Tax Relief for Pollution Control Property Program, you will be notified of any rulemaking which may amend 30 Tex. Admin. Code Chapter 17.

If you have any questions or require any additional information, please contact the Tax Relief for Pollution Control Property Program at (512) 239-6348.

Sincerely,

Ronald Hatlett
Tax Relief for Pollution Control Property

13544 Revised

NO MONEY

Received and Original
Forward to Dept.
MAR 07 2012
TCEQ/Revenue Section

Texas Commission on Environmental Quality

Use Determination for Pollution Control Property Application

A person seeking a use determination must complete this application form. For assistance in completing the application form please refer to the *Instructions for Use Determination for Pollution Control Property Application Form TCEQ-00611*, as well as the rules governing the Tax Relief Program in Title 30 Texas Administrative Code Chapter 17 (30 TAC 17). Information relating to completing this application form is also available in the TCEQ regulatory guidance document, *Property-Tax Exemptions for Pollution Control Property, RG-461*. For additional assistance, please call the Tax Relief Program at 512-239-4900.

You must supply information for each field of this application form unless otherwise noted.

Section 1. Eligibility

1. Is the property/equipment subject to any lease or lease-to-own agreement? Yes ☐ No ☒
2. Is the property/equipment used solely to manufacture or produce a product or provide a service that prevents, monitors, controls, or reduces air, water or land pollution?

   Yes ☐ No ☒
3. Was the property/equipment acquired, constructed, installed, or replaced before January 1, 1994? Yes ☐ No ☒

If the answer to any of these questions is **'Yes'**, then the property/equipment is not eligible for a tax exemption under this program.

Section 2. General Information

1. What is the type of ownership of this facility?

   Corporation ☒ Partnership ☐ Utility ☐
   Sole Proprietor ☐ Limited Partner ☐ Other:

2. Size of Company: Number of Employees

   1 to 99 ☐ 500 to 999 ☐ 2,000 to 4,999 ☐
   100 to 499 ☒ 1,000 to 1,999 ☐ 5,000 or more ☐

3. Business Description: (Briefly describe the type of business or activity at the facility)

   Electric Power Generation and Transmission Cooperative

4. Provide the North American Industry Classification System (NAICS) six-digit code for this facility. 221112

Section 3. Type of Application and Fee

1. Select only one:

   Tier I – Fee: $150 ☐ Tier II – Fee: $1,000 ☐ Tier III – Fee: $2,500 ☐

2. Payment Information:

   Check/Money Order/Electronic Payment Receipt Number:
   Payment Type:
   Payment Amount:
   Name on payment:
   Total Amount:

NOTE: Enclose a check, money order to the TCEQ, or a copy of the ePay receipt along with the application to cover the required fee.

Section 4. Property/Equipment Owner Information

1. Company Name of Owner: Brazos Electric Power Cooperative, Inc.
2. Mailing Address: 2404 LaSalle Ave. ; PO Box 2585
3. City, State, Zip: Waco, Texas, 76702-2585
4. Customer Number (CN): 600128821
5. Regulated Entity Number (RN):100221985
6. Is this property/equipment owned by the CN listed in Question 4? Yes ☒ No ☐

   If the answer is 'No,' please explain:
7. Is this property/equipment leased from a third party? Yes ☐ No ☒

   If the answer is 'Yes,' please explain:
8. Is this property/equipment operated by the RN listed in Question 5? Yes ☒ No ☐

   If the answer is 'No,' please explain:

Section 5. Name of Property/Equipment Operator (If different from Owner)

1. Company Name:
2. Mailing Address:
3. City, State, Zip:
4. Customer Number (CN):
5. Regulated Entity Number (RN):

Section 6. Physical Location of Property/Equipment

1. Name of Facility or Unit where the property/equipment is physically located: Johnson County Generation Facility
2. Type of Mfg. Process or Service: Electric Power Generation
3. Street Address: 831 Sparks Drive

4. City, State, Zip: Cleburne, Texas, 76033

Section 7. Appraisal District with Taxing Authority

1. Appraisal District: Johnson County
2. District Account Number(s):

Section 8. Contact Name

1. Company Name: H&H Associates
2. First Name of Contact: Jim
3. Last Name of Contact: Harris
4. Salutation: Mr. ☒ Mrs. ☐ Ms. ☐ Dr. ☐ Other:
5. Title: President
6. Mailing Address: 406 FM 3016
7. City, State, Zip: Grapeland, Texas, 75844
8. Phone Number/Fax Number: (936) 687-4230 / (936) 687-9064
9. Email Address: h-h@hughes.net
10. Tracking Number (optional):

Section 9. Property/Equipment Description, Applicable Rule, and Environmental Benefit

For each piece, or each category, of pollution control property/equipment for which a use determination is being sought, answer the following questions.

Attach additional response sheets to the application for each piece of integrated pollution control property/equipment if a use determination is being sought for more than one (1) piece.

General Information

1. Name the property/equipment: Heat Recovery Steam Generator (HRSG) and Dedicated Ancillary Systems
2. Is the property/equipment used 100% as pollution control equipment? Yes ☐ No ☒

   If the answer is 'Yes,' explain how it was determined that the equipment is used 100% for pollution control:
3. Does the property/equipment generate a Marketable Product? Yes ☒ No ☐

   If the answer is 'Yes,' describe the marketable product: Electric Power
4. What is the appropriate Tier I Table or Expedited Review List number? B-8
5. Is the property/equipment integrated pollution control equipment? Yes ☒ No ☐

   If the answer is 'No,' separate applications must be filed for each piece of property/equipment.
6. List applicable permit number(s) for the property/equipment: 25384/PSD-TX-839 ; Title V O-00543

Incremental Cost Difference

7. Is the Tier I Table percentage based on the incremental cost difference? Yes ☐ No ☒

   If the answer is 'Yes,' answer the following questions:

8. What is the cost of the new piece of property/equipment?
9. What is the cost of the comparable property/equipment?
10. How was the value of the comparable property/equipment calculated?

Property/Equipment Description

11. Describe the property/equipment. (What is it? Where is it? How is it used?) See Attachment 1

Applicable Rule

12. What adopted environmental rule or regulation is being met by the construction or installation of the property/equipment? The citation must be to the subsection level.

Environmental Benefit

13. What is the anticipated environmental benefit related to the construction or installation of the property/equipment? See Attachment 2

Section 10. Process Flow Diagram (Optional)

Attach documentation to the application showing a Process Flow Diagram for the property/equipment.

Section 11. Partial-Use Percentage Calculation

This section must be completed for all Tier III applications. Attach documentation to the application showing the calculations used to determine the partial-use percentage for the property/equipment.

Section 12. Property Categories and Costs

List each piece of property/equipment of integrated pollution control property/equipment for which a use determination is being sought.

Property/Equipment Name	Tier 1 Table No. or Expedited Review List No.	Use Percent	Estimated Dollar Value
Land:			
Property: Heat Recovery Steam Generator and Dedicated Ancillary Sys	B-8	60.73	$28,111,986
Property:			
Property:			
		Total:	$17,072,753

Attach additional response sheets to the application if more than three (3) pieces.

NOTE: Separate applications must be filed for each piece of nonintegrated pollution control property/equipment.

Section 13. Certification Signature

Must be signed by owner or designated representative.

By signing this application, I certify that I am duly authorized to submit this application form to the TCEQ and that the information supplied here is true and accurate to the best of my knowledge and belief.

Printed Name: Mike Meyers Date:

Signature: Mike Meyers 3/5/2012

Title: Manager, Environmental Services

Company Name: Brazos Electric Power Cooperative, Inc.

Under Texas Penal Code 37.10, if you make a false statement on this application, you could receive a jail term of up to one year and a fine up to $2,000, or a prison term of two to 10 years and a fine of up to $5,000.

Application Submission

Send the completed application and the appropriate fee, along with a complete copy of the completed application for the appraisal district, to:

U.S. Mail

Cashiers Office, MC 214
Tax Relief Program
TCEQ
PO Box 13088
Austin TX 78711-3088

Physical Address

Cashier's Office, MC 214
Building A
TCEQ
12100 Park 35 Circle
Austin TX 78753

Brazos Electric Power Cooperative, Inc.
Johnson County Generation Facility
HRSG

Pollution Control Property/Equipment Use Determination

Attachment 1

9.11. Describe the property. (What is it? Where is it? How is it used?)
The pollution control property described in this application is the heat recovery steam generator (HRSG) and dedicated ancillary systems (PC Property) installations.

Johnson County – HSRG

The Facility consists of a combined –cycle gas turbine power plant with (1) gas combustion turbine (CT) equipped with a heat recovery steam generator (HRSG) and dedicated ancillary systems necessary to capture heat from the CTs exhaust and convert it into electrical power. The HRSG is installed at the exit of the CT to capture and utilize the waste heat of combustion from the CTs exhaust gas and utilizes this waste heat to produce steam, which in turn powers a steam turbine-generator set to produce electrical power at the Facility in addition to the electrical power generated by the CT alone.

The Facility gains both production and pollution control benefits from the subject PC Property. First, the use of this waste heat of combustion by the HRSG creates a thermal efficiency benefit for the Facility. Specifically, the use of waste heat from the CT exhaust gas results in the conversion of some of 50-55% of the chemical energy of the natural gas utilized at the Facility into electricity (HHV basis), a gain over the approximately 36% efficiency of the CTs alone use of the fuel in a simple cycle gas turbine (Brayton Cycle). Secondly, due to this efficiency gain, the Facility is able to generate fewer emissions (particularly NOx emissions) than a traditional power generation facility utilizing a single thermodynamic cycle; and allowing the subject PC Property to appear on the Expedited Review List.

9.12. What adopted environmental rule or regulation is being met by the construction or installation of this property?
The Pollution Control Property (PC) was installed to meet the requirements of 40 CFR Part 60.44da(a) "Standards for nitrogen oxides (NOX) for Electric Utility Steam Generating Units for new source performance standards (NSPS).

As well, the PC Property allows emissions to meet or exceed best available control technology (BACT) emission limitations established in federal operating permit # O-543. Per 30 Texas Administration Code (TAC) §122.143(4), the permit holder must comply with all terms and conditions codified in the permit and any provisional terms and conditions required to be oncluded with the permit.

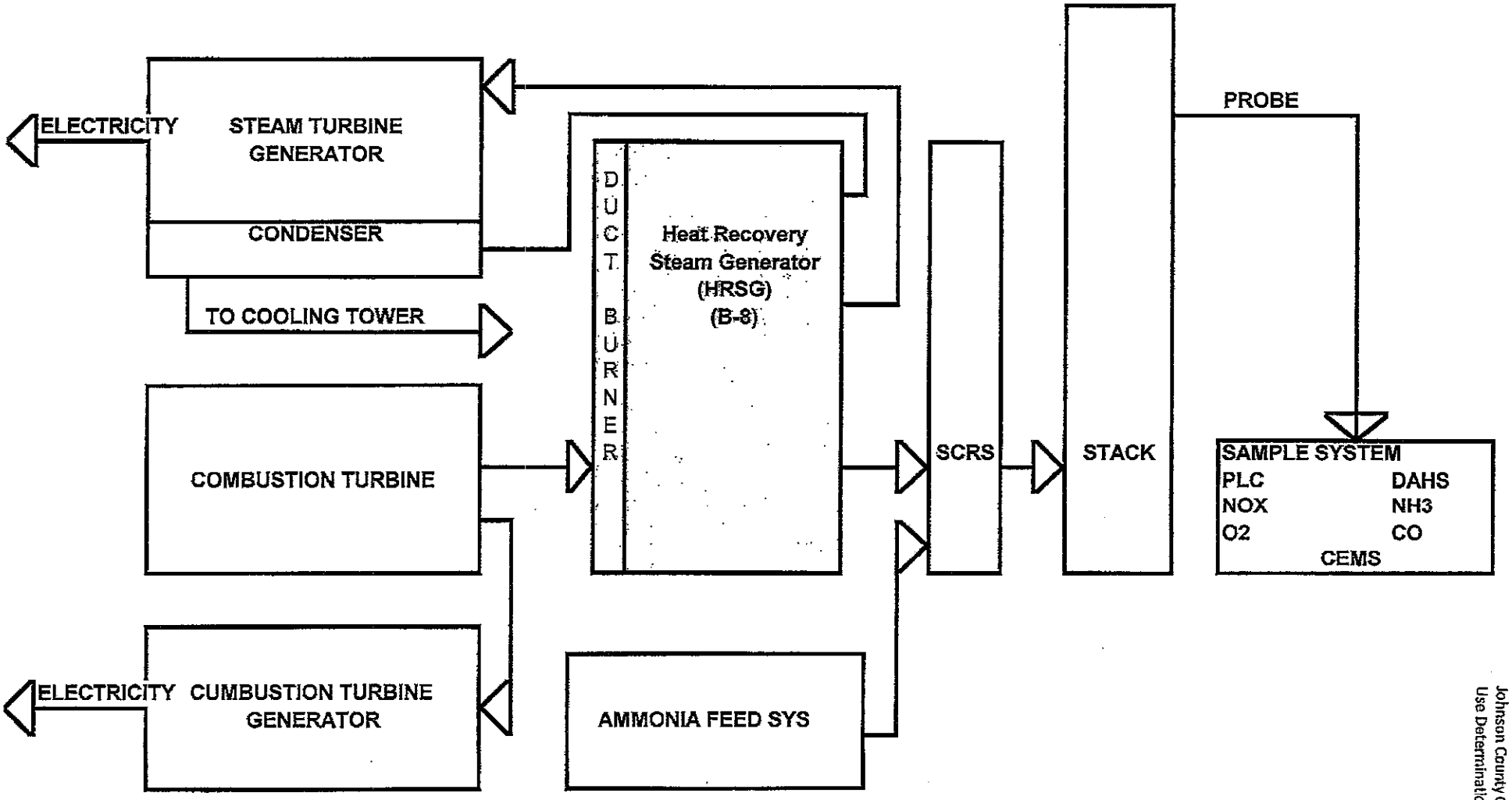
9.13. What is the anticipated environmental benefit related to the construction or installation of the property?

The PC Property reduces the formation of and/or controls the emission of NOx and other air emissions associated with the combustion of natural gas used in combined cycle power generation at the Facility. Since less fuel is required per kilowatt of power produced, less exhaust gas emissions (NOx, CO, CO2) are emitted. Therefore, the HRSG's primary purpose of capturing and converting waste heat from the combustion turbine results in meaningful environmental benefits.

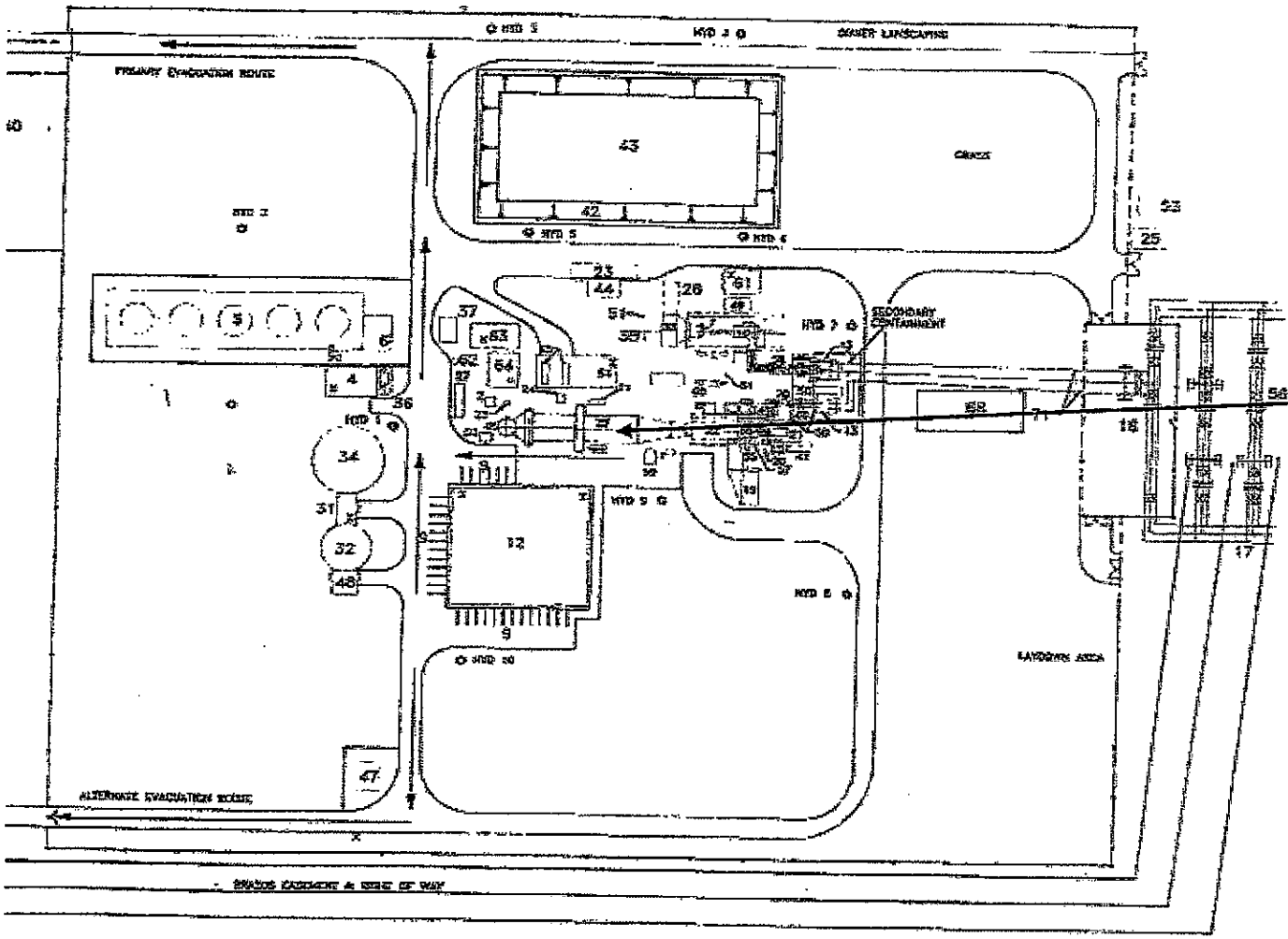
See Attachment 4 for calculation methodology used to calculate the partial use determination per requirements of TCEQ Pub. No. RG-461.

Brazos Electric Power Cooperative, Inc.
Johnson County Generation Facility

Pollution Control Equipment Use Determination Document
Attachment 2



Brazos Electric Power Cooperative, Inc
Johnson County Generation Facility
Use Determination Application # 13544



POWER PLANT LEGEND

NO.	DESCRIPTION
1.	NATURAL GAS SCRUBBER
2.	BOILER DRAIN SUMP
3.	CITY WATER METER
4.	COOLING TOWER WATER TREATMENT BUILDING
5.	COOLING TOWER
6.	CIRCULATING WATER PUMPS
7.	STEAM TURBINE (5,500 gal lube oil storage)
8.	LIQUID FUEL PACKAGE
9.	PARKING
10.	GENERATORS
11.	DLN3 BURNER MANAGMENT SKID
12.	BUILDING FOR CONTROL & SWITCH GEAR, WATER TREATMENT, OFFICE, MAINTENANCE
13.	GENERATOR STEPUP TRANSFORMERS (9,100 gal oil)
14.	MECHANICAL AND ELECTRICAL CONTROL PACKAGES
15.	BFW PUMPS
16.	
17.	BRAZOS SWITCHYARD
18.	PONDEROSA PINE SWITCHYARD
19.	AIR INLET
20.	EXCITATION TRANSFORMER
21.	STARTING MOTOR
22.	COMBUSTION TURBINE (4,500 gal lub oil storage)
23.	COVERED FUEL TRUCK UNLOADING AREA
24.	AMMONIA BLOWER
25.	BRAZOS RELAY BUILDING
26.	CONDENSER TUBE REMOVAL
27.	AMMONIA TANK (12,000 gal)
28.	BLOWDOWN TANK
29.	HEAT RECOVERY STEAM GENERATOR
30.	
31.	WATER PUMP HOUSE
32.	CITY WATER TANK
33.	SURFACE CONDENSER
34.	DEMINERALIZED WATER STORAGE TANK
35.	CONDENSATE PUMPS
36.	ACID TANK (5,800 gal)
37.	OIL-WATER SEPARATOR (5,000 gal split capacity)
38.	FLOWMETER READOUT CABINET
39.	
40.	COOLING TOWER MAKEUP STORAGE TANK
41.	CO2 FIRE PROTECTION SKID
42.	OIL STORAGE SECONDARY CONTAINMENT (volume greater than tank contents)
43.	OIL STORAGE TANK (1,470,000 gal)
44.	FUEL OIL UNLOADING AND TRANSFER PUMPS
45.	HRSG STACK
46.	UNIT AUX. TRANSFORMERS
47.	NATURAL GAS CUSTODY FILTERS AND METER
48.	FIRE PUMP BUILDING (286 gal carbed fuel oil tank)
49.	STEAM TURBINE MECHANICAL PACKAGE
50.	FIRE WALL
51.	PIPE RACK
52.	CONTINUOUS EMISSION MONITOR BUILDING
53.	COMMUNICATIONS TOWER
54.	BOILER CHEMICAL FEED BUILDING (ALSO BFP'S)
55.	COMPRESSOR ON-LINE OFF-LINE WATER WASH SKID
56.	BRAZOS DISTRIBUTION SUBSTATION
57.	NEUTRAL GROUNDING CUBICLE
58.	GENERATOR AUXILIARIES CMPT
59.	FUEL GAS PREHEATER
60.	KETTLE BOILER
61.	VACUUM PUMP HOUSE
62.	SEWER MANHOLE
63.	DISTILLED WATER SYSTEM COOLING TOWER
64.	DISTILLED WATER EVAPORATOR COLUMN
65.	GRAY WATER METER
66.	WELL WATER METER
67.	
68.	NEW WAREHOUSE
69.	
70.	GENERATOR BREAKER
71.	OVERHEAD TRANSMISSION LINE

Attachment 3

Brazos Electric Power Cooperative, Inc
Johnson County Generation Facility
Use Determination Application # 13544

Brazos Electric Power Cooperative, Inc.
Johnson County Generation Facility
Cleburne, Texas
Plot Plan

Attachment 4

TCEQ Use Determination Application Section 11 use:

Company:	Brazos Electric Power Cooperative, Inc.
Plant:	Johnson County Generation Facility
Unit:	258 MW 1 x 1 Configuration Combined Cycle Power Plant (1996)
Address:	Cleburne, Texas
Project:	Tier III Cost Analysis Procedure
Date:	10-Feb-12

I. Assumptions

Pollution Control Property (PC)		Source
Property Cost:	$28,111,986.00	BEC Acctlng
Capital Cost ($/KW):	$326.88	PC/TC
Total Capacity (MW):	258	∑(CT+ST)
CT Capacity (MW)	172	BEC 2010 RUS Form 12
ST Capacity (MW)	86	BEC 2010 RUS Form 12
2010 Net Annual ST Generation Capacity (KWhr):	487,215,000	BEC 2010 RUS Form 12
2010 Net Annual ST Generation Capacity (MWhr):	487,215	BEC 2010 RUS Form 12
2010 ST Capacity Factor:	64.67	Energy/(TC * 8760)
2010 Plant Heat Rate (btu/kwhr):	7,782	BEC 2010 RUS Form 12
2010 Plant Heat Rate (mmbtu/kwhr):	0.008	NPHR/1E06
2010 Operating Hours	7,606	BEC 2010 RUS Form 12
Capital Cost Old:	0	
Comparable Technology Cost:	0	
Comparable Technology:	0	
Design Capacity Factor:	0	
Capacity (MW):	1	

Conversion Factors	
Hrs/yr	8760
KW/MW	1000
lb/kg	2.2
s/hr	3600
btu/mmbtu	1000000

Economic Assumptions		Source
Discount Rate (%)	10.00%	Standard project rate
Periods (Yrs)	30	RUS depreciation
PC Property Fixed O&M Cost ($/KW-yr)	$6,126,060	BEC 2010 RUS Form 12
CT Fixed O&M Costs ($)	$4,084,040	Formula
ST Fixed O&M Costs ($)	$2,042,020	Formula
Fuel Cost ($/MMBTU)	$4.11	Note 1
PC property Variable Cost ($/MWh)	$5.00	Check with OSE
PC property Variable Cost ($/KWh)	$0.0050	Formula
ERCOT Electricity Pricing ($/MWh)	$44.48	Note 2
Interest Rate (%)	10.00%	

Note 1: Average cost for fuel (2009 - 2011) weighted by monthly steam turbine generation

Note 2: Average Settlement Point price for resource weighted by hourly steam turbine generation, reflected by North Load Zone Market Clearing Price for Energy (MCPE) for Jan 1, 2009 - Nov 30, 2010 and Real-time

Levelized Cost of Energy (LCOE) Model Outputs	
Capitol Recovery Factor (%)	10.81%
LCOE ($/KWh)	0.03079

II. Cost Analysis Procedure

A. $$\frac{[(\text{Production Capacity Factor} \times \text{Capital Cost New}) - \text{Capital Cost Old} - \text{Marketable Product}]}{\text{Capital Cost New}}$$

B. Cost Analysis Procedure Formulas (TCEQ)

Partial Use Determination

$$\frac{[(\text{Production Capacity Factor} \times \text{Capital Cost New}) - \text{Capital Cost Old} - \text{Marketable Product Value}]}{\text{Capital Cost New}}$$

where: Marketable Product Value = $$\sum_{t=1}^{n} \frac{\text{Marketable Product Value} - \text{Production Cost}}{(1 + \text{Interest Rate})^{n}}$$

n = estimated useful life in years of years equipment

t = year one

Interest Rate = 10%

C. Cost Analysis Procedure for Pollution Control Property

Marketable Product Value = Electricity Price ($/MWh) x MWh per Year

Direct Cost of Production = Levelized Cost of Energy x KWh per Year

LCOE ($/KWh) $$\frac{(\text{Capital Cost} \times \text{Capital Recovery Factor}) + \text{Fixed O\&M Costs}}{\text{Hours per Year} \times \text{Capcity Factor}} + (\text{Fuel Cost} \times \text{Heat Rate})$$

Capital Recovery Factor (CRF) $\frac{i \times (1+i)^n}{(1+i)^n - 1}$

(PC)	(CRF)		(Annual cost to carry)		(FOM)	(Total Annual PC)	
$28,111,986.00	10.23%	=	$2,875,856.17	+	$2,042,020	$4,917,876.17	
						$0.0101	/kWh
					(Fuel x NPHR)	$0.0820	
					LCOE:	$0.04208	($/kWh)

Attachment 4, cont'

III. Cost Analysis Procedure Calculations For Jack County (Jack 1) HRSG1 and HRSG2

Formula: $\frac{(PCF \times CCN) - CCO - NPVMP}{CCN}$

A. Marketable Product Value (MPV)

Electricity Price $\frac{\$}{MWh} \times \frac{\text{Plant MWh}}{\text{Year}}$ = ($) MPV

$44.48 x 487,215 = $21,671,323.20

B. Production Cost (PC)

Levelized Cost Of Energy (LCOE) $\frac{\$}{KWh} \times \frac{\text{Plant MWh}}{\text{Year}}$ = ($) PC

$0.04208 x 487,215,000 = $20,500,289.64

Net Present Value Marketable Product (NPVMP) Calculation

$$\sum_{t=1}^{n} \frac{\text{Marketable Product Value} - \text{Production Cost}}{(1 + \text{Interest Rate})^{n}} = \text{NPVMP ($)}$$

$$\sum_{t=1}^{n} \frac{\$21,671,323.20 - \$20,500,289.64}{1.10} = \text{NPVMP } \$11,039,233.23$$

C. Production Capacity Factor (PCF)

$$\frac{\text{Production Capacity of Existing Equipment or Process}}{\text{Production Capacity of New Equipment or Process}} = \text{PCF}$$

$$\frac{0}{86 \text{ MW} \times 56.21\%} = \text{PCF } 1.00$$

If MP is <= 0, then MP = 0

D. Capital Cost New (CCN)

Pollution Control Property (PC) = CCN $28,111,986.00

E. Capital Cost Old (CCO)

Comparable Technology = CCO $0.00

Partial Use Determination Calculation

$$\frac{(PCF \times CCN) - CCO - MP}{CCN} = \text{Partial Use Determination \%}$$

$$\frac{\$28,111,986.00 - \$0.00 - \$11,039,233.23}{\$28,111,986.00} = 60.73\%$$

TCEQ Use Determination Application Section 11 use:	
Use Percent	60.73%
Estimated Dollar Value	$28,111,986.00

Eligible HRSG Costs
(Partial Use Determination % x PC Property) = $17,072,752.77

Bryan W. Shaw, Ph.D., *Chairman*
Carlos Rubinstein, *Commissioner*
Toby Baker, *Commissioner*
Zak Covar, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

February 21, 2013

Mr. Jim Harris
Agent
H & H Associates
406 FM 3016
Grapeland, Texas 75844

Re: Notice of Technical Deficiency
Brazos Electric Power Cooperative, Inc.
Johnson County Generation Facility
831 Sparks Drive
Cleburne (Johnson County)
Regulated Entity Number: RN100221985
Customer Reference Number: CN600128821
Application Number: 13544

Dear Mr. Harris:

This letter responds to Brazos Electric Power Cooperative, Inc.'s Application for Use Determination, received April 27, 2009 pursuant to the Texas Commission on Environmental Quality's (TCEQ) Tax Relief for Pollution Control Property Program for the Johnson County Generation Facility.

The TCEQ has conducted further technical review and determined that additional information required by Title 30 Texas Administrative Code (TAC) §17.10 is warranted for application #13544. Please revise your application to include the following.

Issue 1: Please review the enclosed application to ensure that all information is still current.

Issue 2: Specify the subsections of Title 40 Code of Federal Regulations (CFR) §60 Subpart Da being met as a result of the installation and use of the heat recovery steam generators (HRSG) and explain how the HRSG use causes the facility to meet or exceed the rule.

Issue 3: Provide a copy of permit O-00543. Explain where in the permit HRSGs are required Best Available Control Technology.

Issue 4: Provide a list of the equipment included in the description "Dedicated Ancillary Systems." Does this listing include items that appear on either the Tier I Table located in 30 TAC §17.14(a) or the Expedited Review List located in 30 TAC §17.17(b)?

Issue 5: Please resubmit your partial calculation. We agree that the proper method for calculating a partial use determination is the Cost Analysis Procedure located

To determine the electrical power represented by $W_{thermal}$, $W_{thermal}$ must be converted to electrical power using the thermal efficiency ($\eta_{thermal}$) of the steam turbine(s). You may either use the rated efficiency of the actual steam turbine at the facility or assume $\eta_{thermal}$ of 36%, which is an average steam turbine thermal efficiency for non-nuclear applications.

$$W_{electrical} = W_{thermal} \times \eta_{thermal}$$

$W_{electrical}$ represents the electrical power generation associated with the HRSG. In order to determine the marketable product value, multiply this value by the number of hours the HRSG operated in each of the last three years while electricity was being generated for sale or use on site. This value should then be multiplied by the average retail rate of electricity sold during each of the last three years in order to determine the marketable product value of the steam used to generate electricity sold to external parties or used on site for the last three years. The marketable product values for the last three years should be added and the sum divided by three to obtain the average marketable product value over the last three years.

- Production Cost: Itemized costs directly attributed to the operation of the HRSG excluding non-cash costs, such as overhead and depreciation and excluding costs related to operating the gas turbine, associated duct burners, or the steam turbine including fuel costs.
- Interest Rate: 10%
- n: estimated useful life in years of the HRSG

The TCEQ appreciates your response in this matter. The revised application must be submitted by March 26, 2013 to the TCEQ Tax Relief for Pollution Control Property Program, MC-110, P.O. Box 13087, Austin, Texas 78711-3087. Failure to submit a complete application, including the requested information, may result in your application being voided and the associated application fee being forfeited in accordance with 30 TAC §17.20(b).

If you have questions regarding this letter or need further assistance, please contact Ronald Hatlett of the Tax Relief for Pollution Control Property Program by telephone at (512) 239-6348, by e-mail at ronald.hatlett@tceq.texas.gov, or write to the Texas Commission on Environmental Quality, Tax Relief for Pollution Control Property Program, MC-110, P.O. Box 13087, Austin, Texas 78711-3087.

Sincerely,

Chance Goodin, Team Leader
Stationary Source Programs
Air Quality Division

CG/RH

NORTON ROSE FULBRIGHT

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June 24, 2013

VIA EMAIL & U.S. MAIL

Mr. Ronald Hatlett
TCEQ
Tax Relief for Pollution Control Property Program
MC-110
P.O. Box 13087
Austin, Texas 78711-3087

RE: Brazos Electric Power Cooperative Inc; Johnson County Generation Facility; Use Determination Application No. 13544; Response to Notice of Technical Deficiency

Dear Mr. Hatlett:

On behalf of Brazos Electric Power Cooperative, Inc. ("BEPC"), I am submitting this response to the Notice of Technical Deficiency ("NOTD") issued by the Executive Director's staff on February 21, 2013. A copy of the NOTD is attached hereto as Attachment A. Through the NOTD, the Executive Director's staff requested additional information related to five issues. In response, BEPC provides the following:

Issue 1: Please review the enclosed application to ensure that all information is still current.

Response: Following a review of Application No. 13544, BEPC provides the following information, which supplements the information previously provided in Application No. 13544:

Section 9.12: BEPC objects to the Executive Director's staff's requirement to identify an environmental regulation that is met or exceeded through the use of a HRSG. The Texas Legislature expressed its intent that HRSGs be treated as pollution control devices when it amended Section 11.31 of the Tax Code in 2007 to include subsection (k). That subsection requires that TCEQ adopt a list of such devices and mandates that HRSGs be included on that list. *See* TEX. TAX CODE § 11.31(k).

Here, the Legislature deliberately and purposefully included HRSGs in its list of items that "must" be treated as "facilities, devices, or methods for the control of air, water, or land pollution ..." TEX. TAX CODE § 11.31(k). The Legislature did so with full knowledge that HRSGs are devices that are necessarily part of the production process and commonly used as power plant components. Accordingly, HRSGs must be treated as pollution control devices and the Executive Director cannot interpret the statute in an alternative manner to avoid this unambiguous legislative mandate.

Section 11.31(m) states:

> (m) Notwithstanding the other provisions of this section, if the ... device is a ... device ... included on the list adopted under Subsection (k), the executive director ... and without regard to whether the information required by Subsection (c)(1) has been submitted ... shall determine that the ... device ... is used wholly

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> or partly as a ... device ... for the control of air, water, or land pollution and shall take the actions that are required by Subsection (d) in the event such a determination is made.

TEX. TAX CODE § 11.31(m). This legislative directive is definitive and unambiguous. The list comprises equipment that the Legislature has conclusively determined meet all criteria to constitute pollution control equipment. The phrase "notwithstanding the other provisions of this section" directly contradicts the Executive Director's staff's position that it must independently evaluate and apply criteria found in other parts of Section 11.31 before a positive use finding may be issued.

Further, the Executive Director is to make his determination without regard to whether the environmental benefit information required by Tex. Tax Code § 11.31(c)(1) has been submitted. The applicants are exempted from submitting information regarding environmental benefit, i.e., the environmental law or rule that is being met or exceeded by the HRSG, because inclusion of equipment on the list represents a legislative determination that environmental benefit exists.

Subject to, and without waiving this objection, the installation of the HRSG and its dedicated ancillary equipment allows BEPC to meet or exceed the following environmental rules or regulations:

(1) 40 C.F.R. Part 60 Subpart Da, and specifically, 40 C.F.R. § 60.44Da (Standard for Nitrogen Oxides);
(2) Clean Air Interstate Rule ("CAIR"); 30 TAC § 101.506;
(3) Greenhouse Gas Regulations;
(4) Best Available Control Technology ("BACT") requirements; 30 TAC §§ 116.10(1), 116.111(a)(2)(C), 116.160(c)(1)(A); 40 C.F.R. § 52.21(b)(12);
(5) 42 U.S.C. § 7401(c);
(6) 30 TAC §§ 117.450, 117.454, 117.456, 117.9030, 117.913;
(7) 40 C.F.R. § 50.11 – establishing National Ambient Air Quality Standards ("NAAQS") for NO_x. HRSGs also assist in meeting NAAQS for SO_2 (40 C.F.R. § 50.17), PM_{10} (40 C.F.R. § 50.6) and CO (40 C.F.R. § 50.8).

BEPC has provided a more detailed discussion of this issue in Attachment B, the substance of which is incorporated herein for all purposes.

Section 11: For purposes of its Application No. 13544, BEPC is submitting a revised calculation to correct an inadvertent error in its prior submission, a copy of which is attached as Attachment C. The revised calculation results in a partial use determination of 64.29%. With this calculation, BEPC is also providing supporting documentation, which is also relied on by BEPC for purposes of the additional calculations provided herein in Attachments K-M.

Section 12: As noted in Section 11 above, BEPC is submitting a revised calculation to correct an inadvertent error in its prior submission. The revised calculation results in a "Use Percent" of 64.29%, which, when multiplied by the Estimated Dollar Value of $28,111,986, results in a Total of $18,073,195.

Issue 2: Specify the subsections of Title 40 Code of Federal Regulations (CFR) §60 Subpart Da being met as a result of the installation and use of the heat recovery steam

generators (HRSG) and explain how the HRSG use causes the facility to meet or exceed the rule.

Response: 40 C.F.R. § 60.44Da establishes standards of performance for NO_x emissions for electric utility steam generating units for which construction commenced after September 18, 1978, and BEPC began construction of its electric utility steam generating unit long after that date. As described more particularly in the Application itself, BEPC's HRSG helps and was acquired to help the BEPC facility meet or exceed 40 C.F.R. § 60.44Da's emissions standards primarily by reducing fossil fuel consumption and related NO_x emissions. The use of BEPC's HRSG in the combined cycle configuration described in the Application results in significantly lower NO_x emissions for the same electric power that could be generated by a simple cycle plant without pollution control equipment. HRSGs accomplish this result by capturing/recycling and using heat generated by BEPC's combustion turbines to convert water into steam to power steam (rather than natural gas) turbines which produce additional power without use of additional fossil fuel or its associated, additional NO_x emissions. Stated conversely, without its HRSGs, BEPC would be unable to produce the same amount of power without producing more NO_x emissions and might well, in that instance, even exceed the environmental standards of 40 C.F.R. § 60.44Da.

The applicability of 40 C.F.R. Part 60, Subpart Da is premised on the definitions of "affected facility" and "electric utility steam generating unit". The "affected facility" to which 40 C.F.R. Part 60, Subpart Da applies is an electric utility combined cycle gas turbine other than an IGCC electric utility steam generating unit, as specified in 40 C.F.R. § 60.40Da(e)(1) through (3). 40 C.F.R. § 60.40Da(e). "Electric utility steam generating unit" is defined as:

... any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale.

40 C.F.R. § 60.41Da. The HRSG that is the subject of Application No. 13544 is an "affected facility" under 40 C.F.R. § 60.40Da. BEPC's citation of 40 C.F.R. § 60.44Da(a) complies with any requirement to identify an applicable EPA regulation that is met or exceeded through the use and installation of the HRSG.

Further, in the permit issued by the Executive Director to BEPC, dated October 31, 2011, for the Plant that is the subject of Application No. 13544, the Executive Director asserted that the HRSG is subject to Subpart Da. *See* Attachment D, Permit No. 25384 and PSDTX839, Special Condition 14(b). This assertion was repeated in the permit issued by the Executive Director to BEPC on February 13, 2012. *See* Attachment E, Permit No. 25384 and PSDTX839, Special Condition 14(b). BEPC's federal operating permit, No. O-00543, also recognizes that the HRSG is subject to Subpart Da. *See* Attachment F, Applicable Requirements Summary. The Executive Director cannot assert that the HRSG is subject to Subpart Da for purposes of TCEQ's permitting program and then deny that the HRSG is used to meet Subpart Da for purposes of the Tax Relief for Pollution Control Property Program.[1]

[1] As Commissioner Rubenstein noted at the Commission's discussion of the pending HRSG applications, "...I don't disagree that there's great production value in having the HRSGs there. None. Nobody disputes that. But, I also don't think it's appropriate to discount the fact that that efficiency ends up in emission avoidance, and . . . we've touted the improvements in air quality that we've made because we're targeting the emissions, in large respects the increased efficiencies because of the regulations that we have also let us get there, and so we can't like it here and not like it over on this end."

Issue 3: Provide a copy of permit O-00543. Explain where in the permit HRSGs are required Best Available Control Technology.

Response: Please find a copy of permit O-00543, attached hereto as Attachment F. As the Executive Director's staff is aware, the permit does not identify particular pieces of equipment as "required Best Available Control Technology." Best Available Control Technology or BACT is defined as the reduction in total emissions that can be achieved through the use of either (i) add-on pollution control equipment; or (ii) ***production processes***, systems, methods, or work practices. 30 TAC § 116.10(1) (emphasis added). HRSGs serve as part of the production process and reduce the total NO_x emissions from the facility.

BACT is an issue that is addressed through a permit application (*see, e.g.*, Attachment G) and TCEQ's processing of that permit application (*see, e.g.*, Attachment H). The permit reflects the results of that analysis but does not identify specific equipment as being "required Best Available Control Technology." However, as a permit application's representations are considered conditions upon which the permit is issued,[2] and are enforceable as such, BEPC is entitled to rely on these representations for purposes of establishing that the HRSG constituted BACT for the Plant, so as to establish that the HRSG meets or exceeds the requirements of 30 TAC §§ 116.111(a)(2)(C), 116.160(c)(1)(A); 40 C.F.R. § 52.21(b)(12).

Issue 4: Provide a list of the equipment included in the description "Dedicated Ancillary Systems." Does this listing include items that appear on either the Tier I Table located in 30 TAC §17.14(a) or the Expedited Review List located in 30 TAC §17.17(b)?

Response: Enclosed please find, in Attachment I to this Response, the list of equipment for which BEPC claims a use determination. This listing does include items that appear on either the Tier I Table located in 30 TAC § 17.14(a) or the Expedited Review List located in 30 TAC § 17.17(b).

Issue 5: Please resubmit your partial calculation.

Response: For purposes of its Application No. 13544, BEPC is submitting a revised calculation to correct an inadvertent error in its prior submission, a copy of which is attached as Attachment C. The revised calculation results in a partial use determination of 64.29%.

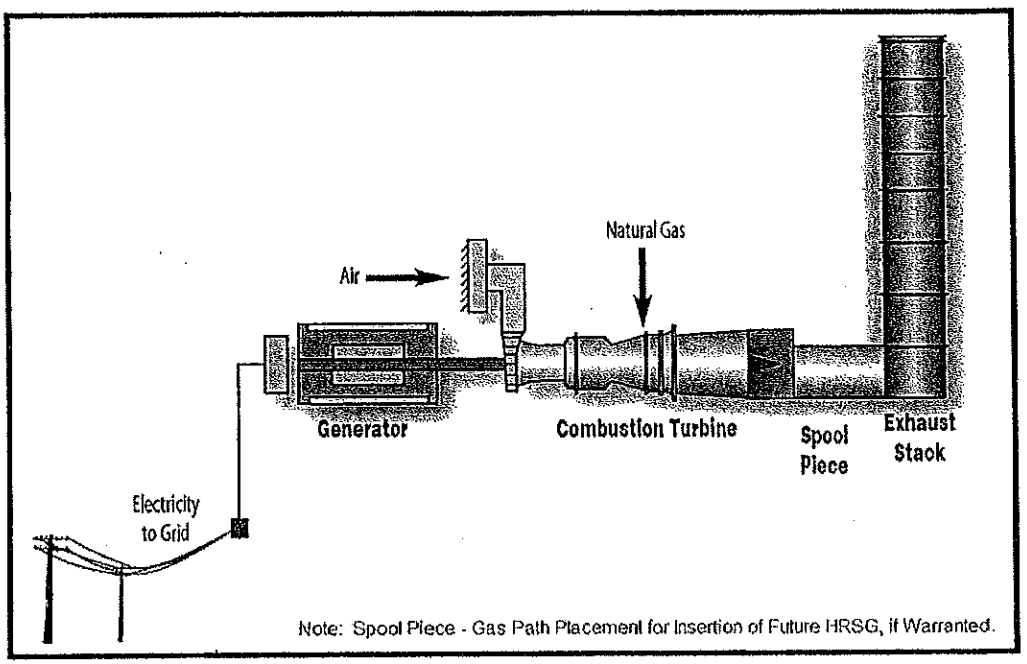
The Executive Director's staff has specifically requested that BEPC calculate a partial use determination using specific inputs for the variables set forth in the Cost Analysis Procedure set forth in 30 TAC § 17.17(b). *See* Attachment A, pp. 2-3. BEPC objects to the Executive Director's staff's mandate of these specific inputs, as this action, without opportunity for notice and comment, constitutes improper and illegal rulemaking. Specifically, the Executive Director's staff has mandated the use of specific equipment it has defined to be the only "comparable equipment" that may considered in a HRSG application, and the exclusion of fuel costs in the calculation of Production Costs, as a part of the calculation of Net Present Value of the Marketable Product.

With respect to the "comparable equipment" variable, the Executive Director's staff has exceeded its authority by mandating one and only one approach to this variable, and further, in that regard, mandating the consideration of quite possibly the most expensive equipment possible. "Comparable equipment" is not a defined term in 30 TAC ch. 17. "Comparable" is

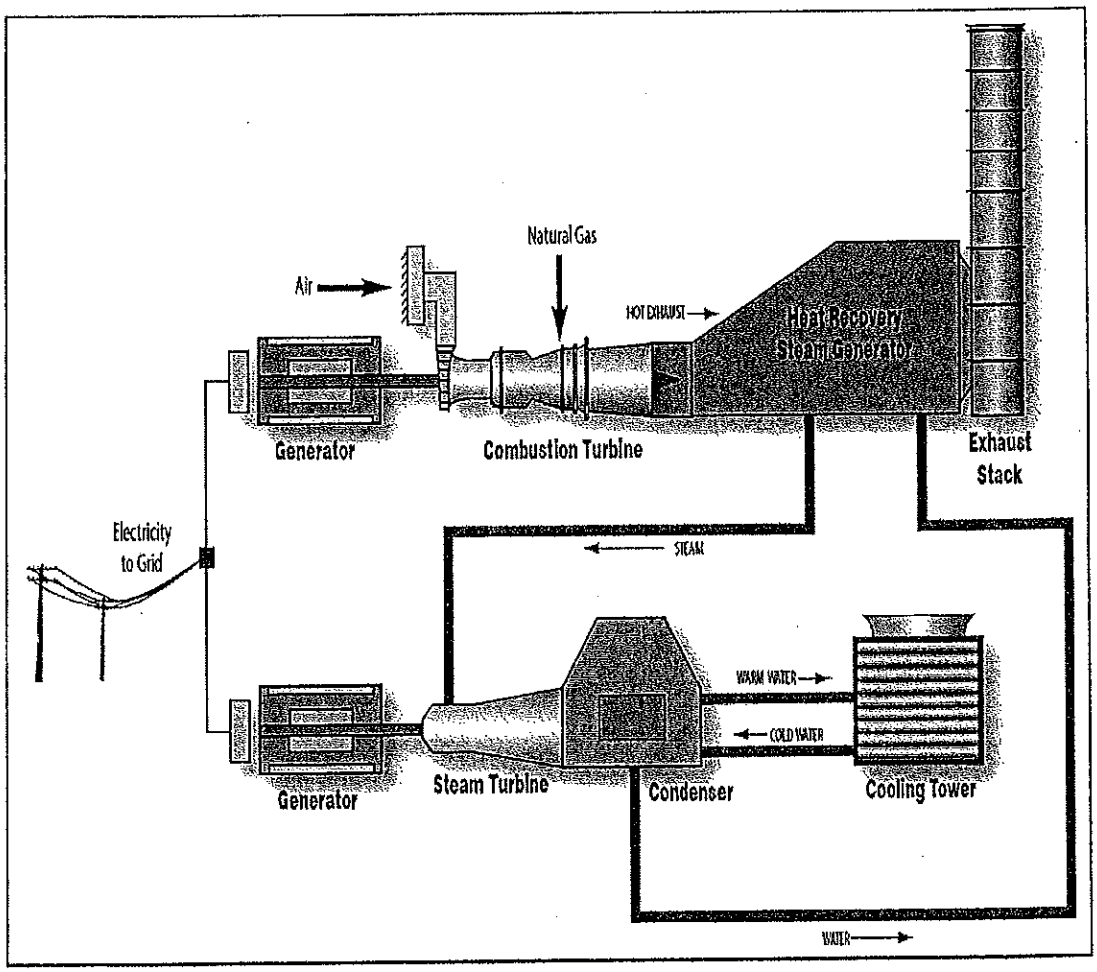
[2] *See* 30 TAC § 116.116(a).

defined in normal usage as similar, or capable of comparison. Synonyms include "analogous," "corresponding," "matching," and "resembling." BEPC asserts that replacement boilers do not match or resemble a HRSG, and therefore the Executive Director's staff's mandate is improper. Indeed, an application of TCEQ's hierarchical definition of "Capital Cost Old," found in 30 TAC § 17.17(c)(1), note 3, will conclude that no CCO should be used in the CAP calculation for a HRSG.

Further, even if replacement boilers were analogous to a HRSG, it cannot be argued that replacement boilers are the only comparable equipment. BEPC has provided a more detailed discussion of its objection in this regard in Attachment J, the substance of which is incorporated herein for all purposes. As noted therein, if a CCO must be used, BEPC asserts that the appropriate comparable equipment is a pipe that would vent heat in the absence of HRSG. The following depiction reflects the proposed pipe replacement:



Under this approach, the spool piece is the comparable equipment that is hypothetically "replaced" by the HRSG, as depicted below:



The staff's mandate of "comparable equipment" that is, in fact, not comparable as hypothetical "replaced" equipment is inappropriate and constitutes improper and illegal rulemaking. On the basis of this objection, BEPC respectfully requests that the Executive Director determine that there be no CCO for CAP calculations related to HRSGs or, in the alternative, that the hypothetical "replaced" equipment be considered to be the piping reflected as the "spool piece" set forth in the first diagram set forth above.

With respect to the exclusion of fuel costs, TCEQ's rules define "Production Cost" as "The costs directly attributed to the production of the product. including raw materials, storage, transportation, and personnel, but excluding non-cash costs, such as overhead and depreciation." 30 TAC § 17.17(c)(2). Through its NOD, the staff narrows the scope of Production Cost by asserting that the cost attributed to the production of electricity, which the staff has designated as the marketable product, must "exclude costs relating to operating the gas turbine, associated duct burners, or the steam turbine including fuel costs." Attachment A, p. 3. Without the operation of these units, and their associated expenses (including fuel costs), no electricity would be generated from any steam produced via the HRSG, and therefore no marketable product would be generated. The staff cannot have it both ways. If electricity is the marketable product, the HRSG Applicants must be allowed to take into account the costs (and the units) associated with generating that marketable product as part of its NPVMP calculation. TCEQ's rules mandate it.

The exclusion of fuel costs from Production Cost is particularly problematic and inappropriate. "Production Cost" expressly includes the cost of "raw materials." *See* 30 TAC § 17.17(c)(2). In this context, fuel is the raw material for the production of the steam and its costs are an element of Production Cost, by definition. Additional costs that are included in Production Cost include storage, transportation, and personnel costs. *See id.* The staff's interpretation of the elements to be included in, and excluded from, the calculation of NPVMP is inaccurate and constitutes improper and illegal rulemaking.. On the basis of this objection, BEPC respectfully requests that the Executive Director determine that fuel costs are to be included in any calculation of Production Costs in the calculation of NPVMP.

Subject to and without waiving this objection, BEPC is submitting a calculation utilizing the mandated inputs for the variables set forth in the Cost Analysis Procedure set forth in 30 TAC § 17.17(b). The mandated calculation results in a partial use determination of -605.08%. *See* Attachment K. Based on an informal review of similarly-situated parties, it is BEPC's conclusion that the calculation, using the specific inputs mandated by the Executive Director's staff, will in each and every case result in a negative use determination, based on a CAP calculation that will greatly exceed -100%. Such a result is no more appropriate than a situation in which a calculation consistently results in a use determination of greater than 100%. For further discussion, see Attachment J. Given this outcome, the Executive Director must revisit the mandated inputs and develop an approach that is consistent with the Legislature's mandate that HRSGs constitute pollution control equipment.

For purposes of facilitating a timely resolution of this matter, and without waiving its rights to pursue a partial use determination of 64.29%, BEPC is submitting alternatives for the Executive Director's consideration. These alternatives are as follows:

(1) The Executive Director's 2008 Adopted Recommendation

On December 3, 2008, the Executive Director affirmatively represented to the Commission that "The Executive Director *intends to apply the adopted recommendation to all subsequently filed similar use determination applications, and to those applications currently pending adjudication.*" Executive Director's December 3, 2008 Response Brief to Rusk County, et al., Appraisal Districts' Appeals of the Executive Director's Use Determinations, § IV, pp. 10-11 (emphasis added). That recommendation was based, among other things, on the Work Group's efforts and read as follows:

> The thermal efficiency increase or production gain derived from the installation of a HRSG is approximately 39%. Since this percentage represents the additional amount of electrical energy produced for a given heat input, it therefore represents the production value of the equipment. Based on this production value, the pollution control percentage of a HRSG installed at a combined-cycle facility is 61%. *Staff is therefore recommending the positive use determination of 61% for the installation of a HRSG in a combined-cycle facility.*

Id. at 11 (emphasis in original).

(2) Avoided NO_x Emissions

The formula included for the calculations under the CAP focuses on the productivity aspects of a piece of equipment, rather than on the pollution control benefits derived from the use of that equipment. BEPC respectfully suggests that the calculation of the equipment should

be focused on its pollution control benefits. One approach to doing so would be to calculate the amount of NO_x emissions that are avoided by the use of the HRSG.

Step 1 of this approach converts the input-based emissions (those calculated based on the input to the process, specifically lb/MMBtu, the format reported to several agencies) to an output-based format (those based on the output of the process, specifically lb/MWh) using BEPC's heat rate (Btu/kW, an industry measure of efficiency comparing fuel consumed to produce a unit of power).

Step 2 multiplies this output-based emission rate by BEPC's capacity and annual capacity factor (a measure of actual plant output compared to the maximum) to calculate annual emissions.

Steps 3 and 4 mirror Steps 1 and 2 but are performed for a "Baseline" simple cycle plant using BEPC's heat rate for a six-unit simple cycle facility.

Step 4 uses BEPC's capacity and capacity factor to calculate the Baseline facility's emissions on an equal basis to BEPC.

Finally, Step 5 calculates the difference in emissions of BEPC and the Baseline facility and then divides by the lower BEPC emissions to arrive at an emissions difference of 39.7%.

The inputs to BEPC's calculations under this approach are specified in Attachment L, which is incorporated herein for all purposes. This approach demonstrates that the Baseline facility, which does not utilize a HRSG, has 39.7% higher emissions than BEPC, which does utilize a HRSG and, thus, that the HRSG provides a 39.7% air pollution control benefit.

(3) HRSG as Replacement for Piping

TCEO has previously asserted, "When a piece of equipment is not replacing previous equipment, instead of zero, capital cost old is the cost of a comparable piece of equipment without the pollution control feature." 35 Tex. Reg. 10964. 10966 (Dec. 10. 2010). A HRSG is a piece of metal, the configuration of which allows for enhanced efficiency and an associated reduction in emissions that would otherwise be generated. Viewed in this context, the comparable piece of equipment without a pollution control feature is simply the piping necessary to fill the gap that would otherwise exist between pieces of equipment if one were to remove the HRSG and its dedicated ancillary equipment.

The CAP calculation would then include the following inputs for the applicable variables:

PCF: the capacity of the existing equipment or process divided by the capacity of the new equipment or process

CCN: Cost of the HRSG and its dedicated ancillary equipment

CCO: Cost of the piping necessary to fill the gap created by the absence of the HRSG and its dedicated ancillary equipment

NPVMP: net present value of the marketable product recovered for the expected lifetime of the property.

Using this approach, the application of the CAP formula results in a positive used determination of 63.76%. The calculations for this approach are specified in Attachment M, which is incorporated herein for all purposes.

(4) CCO and NPVMP as 0

Application of the CAP formula as presented in TCEQ's Notice of Deficiency requires the applicant to imagine a world that bears little resemblance to reality. HRSGs must either exist and function in a complete, combined cycle design, or the subject plant must function pursuant to a completely different, simple-cycle design, without HRSGs. Application of the Tier III CAP formula as proposed presumes that HRSGs operate as a stand-alone revenue source and are able to: 1) produce steam without a fuel input; and 2) convert no-cost steam into electricity without the equipment required to make the conversion.

The CAP is intended to fit for "scrubber-like" equipment that is capable of being added to or removed from existing equipment without requiring any fundamental change in overall plant design or function. Such a scenario is not applicable to the fundamental design changes that HRSGs require when designing a combined cycle, as opposed to a simple-cycle, generating plant, or when converting the latter to the former. Applicants whose pollution control equipment does not fit the logical prerequisites to application of the CAP formula should be allowed the requisite freedom and creativity under the law to develop a calculation of a positive use determination which fits their individual circumstances.

With these caveats in mind, if one were to draw a box around just the HRSG and consider it as a "stand alone" entity and if one were to correct the logical inconsistencies of the CAP formula, the calculation would be as follows:

Production Capacity Factor. TCEQ's Notice of Deficiency directs that the PCF should be calculated "by dividing the capacity of the existing equipment or process by the capacity of the new equipment or process." Because steam turbines and ancillary equipment cannot be considered in any HRSG use determination, the additional electricity generation from that equipment likewise should not be considered when calculating PCF for the HRSGs. Consequently, "Old" and "New" production capacity should be the same, making the PCF equal to 1.

Capital Cost New. The cost of the HRSG, and therefore the CCN, is $28,111,986.

Capital Cost Old. TCEQ's Notice of Deficiency directs that the CCO should be equal to the cost of a boiler(s) required to produce the same amount of steam produced by the HRSGs. Relying on TCEQ's traditional definition of CCO, there is not "comparable equipment . . . without the pollution control feature," and adhering to TCEQ's newly-proposed definition would effectively impose a whole plant design change (to simple cycle or boiler). In this case, there is no comparable equipment without the pollution control feature that can be used for CCO purposes and there is no "old" replacement equipment. Therefore, CCO equals $0.

Net Present Value of the Marketable Product and Production Costs. Calculation of NPVMP for the HRSG requires consideration of an energy input cost, i.e. BTUs in the form of heated air, because the HRSG produces steam only with the energy that is directed to it. This energy has value and, in the alternate reality of a stand-alone HRSG, it would require compensation to the provider of the energy. Without the inclusion of fuel, there is no steam, and without steam, there is no electricity. Without the inclusion of the steam turbines, there is no mechanism for the generation of the electricity from the steam. In the case of the Johnson facility, there is no separate market for the steam generated by the HRSG. Under all of these circumstances, the value of any marketable product from the HRSG is $0.

The foregoing inputs reduce the Tier III CAP formula to the following:

((1 x $28,111,986) – 0 – 0) / ($78,111986)) x 100 =

(($28,111,986) / ($28,111,986)) x 100 =

1 x 100 = 100

Given these parameters, BEPC's Johnson County HRSG would be entitled to a 100% Positive Use Determination.

BEPC appreciates the opportunity to provide the enclosed additional information for the Executive Director's consideration. BEPC understands that TCEQ will be receiving information regarding various approaches that might be utilized to resolve the pending HRSG applications. BEPC is willing and available to meet with the Executive Director and his staff to attempt to resolve these pending applications in an equitable manner. Please contact me if you have any questions or require any additional explanation or information in support of BEPC's Application No. 13544.

Sincerely yours,

Paul C. Sarahan

Attachment A

TCEQ's Notice of Technical Deficiency, dated February 21, 2013

Bryan W. Shaw, Ph.D., *Chairman*
Carlos Rubinstein, *Commissioner*
Toby Baker, *Commissioner*
Zak Covar, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

February 21, 2013

Mr. Jim Harris
Agent
H & H Associates
406 FM 3016
Grapeland, Texas 75844

Re: Notice of Technical Deficiency
Brazos Electric Power Cooperative, Inc.
Johnson County Generation Facility
831 Sparks Drive
Cleburne (Johnson County)
Regulated Entity Number: RN100221985
Customer Reference Number: CN600128821
Application Number: 13544

Dear Mr. Harris:

This letter responds to Brazos Electric Power Cooperative, Inc.'s Application for Use Determination, received April 27, 2009 pursuant to the Texas Commission on Environmental Quality's (TCEQ) Tax Relief for Pollution Control Property Program for the Johnson County Generation Facility.

The TCEQ has conducted further technical review and determined that additional information required by Title 30 Texas Administrative Code (TAC) §17.10 is warranted for application #13544. Please revise your application to include the following.

Issue 1: Please review the enclosed application to ensure that all information is still current.

Issue 2: Specify the subsections of Title 40 Code of Federal Regulations (CFR) §60 Subpart Da being met as a result of the installation and use of the heat recovery steam generators (HRSG) and explain how the HRSG use causes the facility to meet or exceed the rule.

Issue 3: Provide a copy of permit O-00543. Explain where in the permit HRSGs are required Best Available Control Technology.

Issue 4: Provide a list of the equipment included in the description "Dedicated Ancillary Systems." Does this listing include items that appear on either the Tier I Table located in 30 TAC §17.14(a) or the Expedited Review List located in 30 TAC §17.17(b)?

Issue 5: Please resubmit your partial calculation. We agree that the proper method for calculating a partial use determination is the Cost Analysis Procedure located

in 30 TAC §17.17. We do not agree with the method used to calculate the variables in your equation. The variables used in the CAP should be calculated as follows:

$$\frac{(\text{Production Capacity Factor} \times \text{Capital Cost New}) - \text{Capital Cost Old} - \text{NPVMP}}{\text{Capital Cost New}} \times 100$$

- Production Capacity Factor: calculated by dividing the capacity of the existing equipment or process by the capacity of the new equipment or process.
- Capital Cost New: Cost of HRSGs
- Capital Cost Old: Cost of a boiler(s) required to the produce same amount of steam produced by the HRSGs.
- Net Present Value of the Marketable Product: The net present value of the marketable product recovered for the expected lifetime of the property, calculated using the equation in §17.17(c)(2).

$$\text{NPVMP} = \sum_{t=1}^{n} \frac{(\text{Marketable Product Value} - \text{Production Cost})_t}{(1 + \text{Interest Rate})^t}$$

- Marketable Product:

  1. If steam is used to generate electricity that is sold to external parties or used on site, then the value of the marketable product is considered the value of electricity sold or used on site as a result of the steam generated by the HRSG.
  2. If steam is sold to an external party, then the value of the marketable product is considered to be the retail value of the steam sold.
  3. If steam is used on site, then the value of the marketable product is the value assigned to the steam for internal accounting purposes. It is the responsibility of the applicant to show that the internally assigned value is comparable to the value assigned by other similar producers of steam.

For 1 above, the thermal power of steam generated by the facility is converted into electrical power. Using steam tables and basic thermodynamic equations, the thermal power of the steam can be determined.

$W_{thermal} = (h_1 - h_0) \times m$

where h_0 is the initial specific enthalpy of the liquid (the HRSG feedwater) and h_1 is the final specific enthalpy of the steam at a given temperature and pressure exiting the HRSG. m is the mass flow rate of the steam. Use the steam tables to determine the specific enthalpy of the steam based on the required specifications (temperature and pressure) of the steam produced.

To determine the electrical power represented by $W_{thermal}$, $W_{thermal}$ must be converted to electrical power using the thermal efficiency ($\eta_{thermal}$) of the steam turbine(s). You may either use the rated efficiency of the actual steam turbine at the facility or assume $\eta_{thermal}$ of 36%, which is an average steam turbine thermal efficiency for non-nuclear applications.

$$W_{electrical} = W_{thermal} \times \eta_{thermal}$$

$W_{electrical}$ represents the electrical power generation associated with the HRSG. In order to determine the marketable product value, multiply this value by the number of hours the HRSG operated in each of the last three years while electricity was being generated for sale or use on site. This value should then be multiplied by the average retail rate of electricity sold during each of the last three years in order to determine the marketable product value of the steam used to generate electricity sold to external parties or used on site for the last three years. The marketable product values for the last three years should be added and the sum divided by three to obtain the average marketable product value over the last three years.

- Production Cost: Itemized costs directly attributed to the operation of the HRSG excluding non-cash costs, such as overhead and depreciation and excluding costs related to operating the gas turbine, associated duct burners, or the steam turbine including fuel costs.
- Interest Rate: 10%
- n: estimated useful life in years of the HRSG

The TCEQ appreciates your response in this matter. The revised application must be submitted by March 26, 2013 to the TCEQ Tax Relief for Pollution Control Property Program, MC-110, P.O. Box 13087, Austin, Texas 78711-3087. Failure to submit a complete application, including the requested information, may result in your application being voided and the associated application fee being forfeited in accordance with 30 TAC §17.20(b).

If you have questions regarding this letter or need further assistance, please contact Ronald Hatlett of the Tax Relief for Pollution Control Property Program by telephone at (512) 239-6348, by e-mail at ronald.hatlett@tceq.texas.gov, or write to the Texas Commission on Environmental Quality, Tax Relief for Pollution Control Property Program, MC-110, P.O. Box 13087, Austin, Texas 78711-3087.

Sincerely,

cgoodin

Chance Goodin, Team Leader
Stationary Source Programs
Air Quality Division

CG/RH

Attachment B

BEPC's Discussion of the Environmental Rules Met or Exceeded by its HRSG and its Dedicated Ancillary Equipment

On May 1, 2008, the Executive Director issued six positive use determinations for HRSGs, each of which was premised on the HRSGs use to meet or exceed the requirements of 40 C.F.R. Part 60, Subpart Da. See Exhibit "1" to this Attachment. In the Technical Review Document that was provided for and in support of each positive use determination, the Executive Director expressly found, among other things, that "the appropriate [supporting] rule is: 40 CFR 60.44Da."

BEPC agrees that one "appropriate [supporting] rule is: 40 CFR 60.44Da" and so reiterates its reliance upon 40 C.F.R. § 60.44Da in support of the Application, as stated therein originally. This portion of 40 C.F.R. Part 60, Subpart Da establishes standards of performance for NOx emissions for electric utility steam generating units for which construction commenced after September 18, 1978. BEPC began construction of its electric utility steam generating unit long after that date. As described more particularly in the Application itself, BEPC's HRSG help and were acquired to help BEPC to meet or exceed 40 CFR 60.44Da's emissions standards primarily by reducing fossil fuel consumption and related NOx emissions. The use of BEPC's HRSG in the combined cycle configuration described in the Application results in significantly lower NOx emissions for the same electric power that could be generated by a simple cycle plant without pollution control equipment. A HRSG accomplishes this result by capturing/recycling and using heat generated by BEPC's combustion turbines to convert water into steam to power steam (rather than natural gas) turbines which produce additional power without use of additional fossil fuel or its associated, additional NOx emissions. Stated conversely, without its HRSG, BEPC would be unable to produce the same amount of power without producing more NOx emissions and might well, in that instance, even exceed the environmental standards of 40 C.F.R. § 60.44Da.

The applicability of 40 C.F.R. Part 60, Subpart Da is premised on the definitions of "affected facility" and "electric utility steam generating unit". The "affected facility" to which 40 C.F.R. Part 60, Subpart Da applies is an electric utility combined cycle gas turbine other than an IGCC electric utility steam generating unit, as specified in 40 C.F.R. § 60.40Da(e)(1) through (3). 40 C.F.R. § 60.40Da(e). "Electric utility steam generating unit" is defined as:

... any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale.

40 C.F.R. § 60.41Da. The HRSG that is the subject of Application No. 13544 is an "affected facility" under 40 C.F.R. § 60.40Da. BEPC's citation of 40 C.F.R. § 60.44Da(a) complies with any requirement to identify an applicable EPA regulation that is met or exceeded through the use and installation of the HRSG.[3]

[3] EPA's recognition of the environmental benefits of combined-cycle units pre-dates its most recent consideration of the technology for purposes of reducing GHGs. In 2004, and again in 2006, EPA developed an economic impact analysis with respect to regulations it was developing under Section 111 of the Clean Air Act for new stationary combustion turbines. The proposed. and ultimately adopted, regulations were designed to reduce emissions of NOx and sulfur dioxide generated by the combustion of fossil fuels in new combustion turbines. See 40 C.F.R. Part 60, Subpart KKKK; 71 Fed. Reg. 38482

Further, in the permit issued by the Executive Director to BEPC, dated October 31, 2011, for the Plant that is the subject of Application No. 13544, the Executive Director asserted that the HRSG is subject to Subpart Da. See Attachment D, Special Condition 14(b). This assertion was repeated in the permit issued by the Executive Director to BEPC on February 13, 2012. See Attachment E, Special Condition 14(b). BEPC's federal operating permit, No. O-00543, also recognizes that the HRSG is subject to Subpart Da. See Attachment F, Applicable Requirements Summary. The Executive Director cannot assert that the HRSG is subject to Subpart Da for purposes of TCEQ's permitting program and then deny that the HRSG is used to meet Subpart Da for purposes of the Tax Relief for Pollution Control Property Program.

Additional Regulatory Bases Supporting the Application

Although it is sufficient to cite to solely one environmental rule that is met or exceeded with the use of a HRSG, BEPC has cited, in the Response to which this discussion is attached, several other regulations that are met or exceeded through the use of a HRSG. These include:

(1) CAIR; 30 TAC § 101.506;
(2) GHG;
(3) BACT; 30 TAC §§ 116.10(1), 116.111(a)(2)(C), 116.160(c)(1)(A); 40 CFR § 52.21(b)(12);
(4) 42 U.S.C. § 7401(c);
(5) 30 TAC §§ 117.450, 117.454, 117.456, 117.9030, 117.9130;
(6) 40 C.F.R. § 50.11 – establishing National Ambient Air Quality Standards ("NAAQS") for NOx. HRSGs also assist in meeting NAAQS for SO2 (40 C.F.R. § 50.17), PM10 (40 C.F.R. § 50.6) and CO (40 C.F.R. § 50.8).

CAIR

The facility's HRSG also meets or exceeds the requirements of the CAIR. CAIR was implemented by the EPA to reduce the interstate transport of pollutants, especially NOx and sulfur dioxide. 70 Fed. Reg. 25162 (May 12, 2005). Section 101.506 of TCEQ's rules implementing CAIR's NO_x reductions in Texas directly relies upon increased fuel efficiency. *See* 30 TAC §101.506. The increased fuel efficiency resulting from the use of a HRSG meets or exceeds Section 101.506's requirement to reduce NO_x emissions. These requirements are included as part of BEPC's federal operating permit, No. O-00543. *See* Attachment F, Special Terms and Conditions No. 21.

GHG

An additional set of regulations that makes it clear that HRSGs should qualify as pollution control property is the EPA's and, following the passage of HB 788, the TCEQ's regulation of Greenhouse Gases ("GHG"). Regardless of whether we or the TCEQ might dispute the legality of EPA's actions, EPA has already decided that GHGs must be regulated under the Clean Air Act and has started implementation of that regime through BACT reviews (in SIP-authorized states or via a FIP in Texas) and through the proposal of New Source

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(Jul. 6, 2006). In support of its rulemaking, EPA cited the environmental efficiency gains achieved from combined-cycle combustion turbines. According to EPA. the use of such a turbine system "decreases NOx emissions by 14 percent over simple-cycle combustion turbines and 89 percent over existing_ coal electricity generation plants. In addition, CO2 emissions will be 5 percent lower than emissions from SCCTs and 64 percent lower than existing coal plants." EPA, Economic Impact Analysis of the Stationary Combustion Turbines NSPS: Final Report, Feb. 2006, at 2-3, 2-4.

Performance Standards that, once finalized, will effect an output-based emission limit on GHGs that makes provides yet another regulatory basis for TCEQ's recognition that HRSGs are pollution control equipment.

Based on EPA's GHG BACT reviews to date, efficiency reflected through lower output-based emissions of GHGs is the most important factor in meeting the GHG BACT requirements. In its GHG BACT Guidance Document, the EPA states, "Considering the most energy efficient technologies in the BACT analysis helps reduce the products of combustion, which includes not only GHGs but other regulated NSR pollutants (e.g. NO_x, SO_2, $PM/PM_{10}/PM_{2.5}$, CO etc.) Thus, it is also important to emphasize that energy efficiency should be considered in BACT determinations for all regulated NSR pollutants (not just GHGs)." EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, at 22 (Nov. 2010). The fact that output-based emission reductions have been expressly identified by the EPA as a preferred method of compliance with BACT for a wide range of pollutants should end any debate about whether a sufficient regulatory basis exists to conclude that HRSGs qualify as pollution control property.

BACT

In addition, TCEQ's BACT requirements are met or exceeded by the use of HRSGs. BACT is defined as the reduction in total emissions that can be achieved through the use of either (i) add-on pollution control equipment; or (ii) ***production processes***, systems, methods, or work practices. 30 TAC §116.10(1) (emphasis added). HRSGs serve as part of the production process and reduce the total NOx emissions from the facility.

BACT is an issue that is addressed through a permit application and TCEQ's processing of that permit application. The permit reflects the results of that analysis but does not identify specific equipment as being "required Best Available Control Technology." However, as a permit application's representations are considered conditions upon which the permit is issued, and are enforceable as such, BEPC is entitled to rely on these representations for purposes of establishing that the HRSG constituted BACT for the Plant, so as to establish that the HRSG meets or exceeds the requirements of 30 TAC §§ 116.111(a)(2)(C), 116.160(c)(1)(A); 40 CFR § 52.21(b)(12).

42 U.S.C. § 7401(c)

Congress has established that a primary goal of the Federal Clean Air Act is to encourage or otherwise promote reasonable Federal, State and local government actions for pollution prevent, consistent with the provisions of the Federal Clean Air Act. 42 U.S.C. § 7401(c). BEPC's use of the HRSG helps achieve this goal and, in doing so, meets or exceeds the requirements of the Federal Clean Air Act and the regulations promulgated thereunder.

30 TAC §§ 117.450, 117.454, 117.456, 117.9030, 117.9130

BEPC also relies upon 30 TAC §§ 117.450, 117.454, 117.456, 117.9030, 117.9130 as additional supporting regulations for its Application, as it establishes NOx emissions standards for utility electric generation in a geographic area which includes Johnson County, where the facility that is the subject of Application No. 13544 is located. BEPC's HRSG helps BEPC meet or exceed the standards of 30 TAC §§ 117.450, 117.454, 117.456, 117.9030, 117.9130 in the same way they help meet or exceed the standards of 40 CFR 60.44Da, as described above.

NAAQS

To the extent that any additional regulatory support is needed for the Application, the following environmental rules and regulations also are met or exceeded by the installation of BEPC's HRSG: National Ambient Air Quality Standards ("NAAQS") for NO_X (40 C.F.R. § 50.11), along with 30 TAC §§ 101.20 and 101.21 (incorporating federal standards). Use of a HRSGs also assist in meeting NAAQS for SO_2 (40 C.F.R. § 50.17), PM_{10} (40 C.F.R. § 50.6) and CO (40 C.F.R. § 50.8).

Attachment B – Exhibit 1

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

May 1, 2008

STATE OF TEXAS §
COUNTY OF TRAVIS §
OCT 10 2012

DUFF & PHELPS LLC
GREG MAXIM
919 CONGRESS #1450
AUSTIN, TX 78701

This letter is to inform you that on 5/1/2008, the technical review of Use Determination Application 07-11969 was completed. This application is for:

BRAZOS VALLEY ENERGY LP
BRAZOS VALLEY ENERGY
3440 LOCKWOOD RD
RICHMOND, TX 77469

The use determination is included with this letter. In order to request an exemption, a copy of this Use Determination, along with a completed exemption request form #50-248 (can be found at www.cpa.state.tx.us), must be provided to the Chief Appraiser of the appropriate appraisal district. This request must be made by April 30.

House Bill 3121, enacted during the 77th Legislative Session, established a process for appealing a use determination. The Texas Commission on Environmental Quality (TCEQ) rules that implement the appeals process are at 30 TAC 17.25. Pursuant to 17.25(a)(1), an appeal must be filed within 20 days of receipt of the use determination. Should you choose to appeal the use determination, please submit a copy of your appeal to the TCEQ Tax Relief for Pollution Control Property program at the time of filing the appeal with the Chief Clerk of the commission.

If you have any questions or require any additional information, please contact the Tax Relief for Pollution Control Property Program at (512) 239-3100.

Sincerely,

David Greer
Team Leader, Pollution Prevention

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

USE DETERMINATION

The Texas Commission on Environmental Quality has reviewed Use Determination Application, 07-11969, filed by:

BRAZOS VALLEY ENERGY LP
BRAZOS VALLEY ENERGY
3440 LOCKWOOD RD
RICHMOND TX 77469

The pollution control property/project listed in the Use Determination Application is:

This facility has two thermally efficient heat recovery steam generators (HRSGs) and one steam turbine. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

The outcome of the review is:

A 100% positive use determination for the two Heat Recovery Steam Generators. This equipment is considered to be pollution control equipment and was installed to meet or exceed federal or state regulations.

A negative determination is issued for the steam turbine. The use of the steam turbine does not provide an environmental benefit at the site. The steam turbine is not considered to be pollution control equipment.

Executive Director

May 2 2008
Date

TAX RELIEF FOR POLLUTION CONTROL PROPERTY: TECHNICAL REVIEW DOCUMENT

Reviewed By: RLH App. No.: 07 - 11969 Review Start Date: 4/8/2008

Company Name: BRAZOS VALLEY ENERGY LP
Facility Name: BRAZOS VALLEY ENERGY
County: FORT BEND Outstanding Fees: N
Batch/Voucher Number:B500156

ADMINISTRATIVE REVIEW

Administrative Complete Date:4/8/2008

TIER LEVEL
What Tier is this application? The application was filed as a Tier IV application. Is this the appropriate level?

The property listed on this application, Heat Recovery Steam Generators and a steam turbine are items B8 and B10 on the Equipment and Categories List. This application was filed as a Tier IV. Tier IV is the appropriate level for this application.

RELEVANT RULE, REGULATION, OR STATUTORY PROVISION
The rule listed in the application is: 40 CFR 60.44Da
The appropriate rule is: 40 CFR 60.44Da

Explain why this is the appropriate rule?

40 CFR 60.Subpart DA: Standards of Performance for New Stationary Sources. Standards of performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978. This is an appropriate rule.

BRIEF DESCRIPTION OF PROPERTY
The property is described as:

This facility has two thermally efficient heat recovery steam generators (HRSGs) and one steam turbine. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

Is an adequate description and purpose of the property provided? Does it list the anticipated environmental benefits? Are sketches and flow diagrams provided if needed?

An adequate description of the property was provided, and the purpose of the property was listed. The anticipated environmental benefit is listed. Sketches and flow diagrams were provided.

DECISION FLOWCHART(30 TAC 17.15(a))
Mark the appropriate boxes: Box 3 Box 5 Box 6(IV) Y Box 10(III) Box 12(I) Box 13(II)
PART B DECISION FLOWCHART (17.15(b))
Mark the appropriate boxes: Box 1Y Box 2 Y Box 3 Y

Describe how the property flowed through the Decision Flowchart:

Since the property is listed on Part B of the Equipment & Categories List this property leaves the Decision Flow Chart at Box 6. It passes through Box 1 of the Part B Decision Flow Chart with a yes answer. The use of this property at a combined cycle plant, as opposed to having a simple

cycle plant, provides an environmental benefit of reduced NOx emissions at the site. So there is a Yes answer for Box 2, Since there is a reduction in NOx emissions there is an environmental rule which is being met so there is a yes answer to Box 3. The steam turbine passes through Box 1 on the Part B Decision Flow Chart with a yes answer. Since the use of the steam turbine does not provide an environmental benefit at the site a no answer is the result of Box 2. The steam turbine is not eligible for a positive determination.

TIER III or IV APPLICATIONS

Does your calculation agree with the applicants?

No. The application contains a proposed formula for calculating the pollution control value of the HRSGs and the steam turbine. The formula is outcome determinative, and its focus is not on the pollution control aspect of the property. The Executive Director disagrees with this formula.

PROPERTY CATEGORIES AND COSTS

Is the table completed correctly? Has the applicant certified that all listed property became taxable for the first time after January 1, 1994? Is all information necessary for conducting the technical review included.

The table was completed correctly. The applicant certified that all listed property became taxable for the first time after January 1, 1994. All the information necessary for conducting the technical review was included on the application.

TECHNICAL DEFICIENCIES

Is the application complete as received: Y If the application was not administratively complete explain below when justifying the final decision in the final determination section. If the application was not technically complete then:

Provide the language to be used in the Notice of Deficiency (NOD) letter:

Summarize the NOD response:

Provide the language used in the second NOD letter:

Summarize the second NOD response:

Provide the language used in the thied NOD letter:

Summarize the third NOD response:

FINAL DETERMINATION

If the property description has been summarized enter the detailed property description:

This facility has two thermally efficient heat recovery steam generators (HRSGs) and one steam

turbine. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

Provide the reason for your final determination:

The Heat Recovery Steam Generators meet all of the requirements of Chapter 17. A positive use determination based on the most appropriate formula should be issued for the Heat Recovery Steam Generators. The most appropriate formula has been determined by the Executive Director. A negative determination should be issued for the steam turbine. The use of the steam turbine does not result in there being an environmental benefit at the site.

Provide the language for the final determination.

A positive use determination of 100% for the two Heat Recovery Steam Generators. A negative determination is issued for the steam turbine. The use of the steam turbine does not provide an environmental benefit at the site. The steam turbine is not considered to be pollution control equipment.

Highlight the required signatures and establish the appropriate due dates.

Reviewed: Ronald Hettel **Date Signed:** 5/1/08

Peer Reviewed: Gary McCracken **Date Signed:** 5-1-08

Team Leader: Daniel [illegible] **Date Signed:** 5/1/08

Section Manager: [illegible] **Date Signed:** MAY 1 2008

Division Director: [illegible] **Date Signed:** MAY 1 2008

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

May 1, 2008

DUFF & PHELPS LLC
GREG MAXIM
919 CONGRESS #1450
AUSTIN, TX 78701

This letter is to inform you that on 5/1/2008, the technical review of Use Determination Application 07-11966 was completed. This application is for:

FREESTONE POWER GENERATION LP
FREESTONE ENERGY CENTER
13.6 MI N ON FM 488
FAIRFIELD, TX 75840

The use determination is included with this letter. In order to request an exemption, a copy of this Use Determination, along with a completed exemption request form #50-248 (can be found at www.cpa.state.tx.us), must be provided to the Chief Appraiser of the appropriate appraisal district. This request must be made by April 30.

House Bill 3121, enacted during the 77th Legislative Session, established a process for appealing a use determination. The Texas Commission on Environmental Quality (TCEQ) rules that implement the appeals process are at 30 TAC 17.25. Pursuant to 17.25(a)(1), an appeal must be filed within 20 days of receipt of the use determination. Should you choose to appeal the use determination, please submit a copy of your appeal to the TCEQ Tax Relief for Pollution Control Property program at the time of filing the appeal with the Chief Clerk of the commission.

If you have any questions or require any additional information, please contact the Tax Relief for Pollution Control Property Program at (512) 239-3100.

Sincerely,

David Greer
Team Leader, Pollution Prevention

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

USE DETERMINATION

The Texas Commission on Environmental Quality has reviewed Use Determination Application, 07-11966, filed by:

FREESTONE POWER GENERATION LP
FREESTONE ENERGY CENTER
13.6 MI N ON FM 488
FAIRFIELD TX 75840

The pollution control property/project listed in the Use Determination Application is:

This facility has four thermally efficient heat recovery steam generators (HRSGs) and two steam turbines. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

The outcome of the review is:

A 100% positive use determination for the four Heat Recovery Steam Generators. This equipment is considered to be pollution control equipment and was installed to meet or exceed federal or state regulations.

A negative determination is issued for the two steam turbines. The use of the steam turbines does not provide an environmental benefit at the site. The steam turbines are not considered to be pollution control equipment.

Executive Director

May 1 2008
Date

TAX RELIEF FOR POLLUTION CONTROL PROPERTY: TECHNICAL REVIEW DOCUMENT

Reviewed By: RLH App. No.: 07 - 11966 Review Start Date: 4/8/2008

Company Name: FREESTONE POWER GENERATION LP
Facility Name: FREESTONE POWER GENERATION LP
County: FREESTONE Outstanding Fees: N
Batch/Voucher Number:B500156

ADMINISTRATIVE REVIEW

Administrative Complete Date:4/8/2008

TIER LEVEL
What Tier is this application? The application was filed as a Tier IV application. Is this the appropriate level?

The property listed on this application, Heat Recovery Steam Generators and a steam turbine are items B8 and B10 on the Equipment and Categories List. This application was filed as a Tier IV. Tier IV is the appropriate level for this application.

RELEVANT RULE, REGULATION, OR STATUTORY PROVISION
The rule listed in the application is: 40 CFR 60.44Da
The appropriate rule is: 40 CFR 60.44Da

Explain why this is the appropriate rule?

40 CFR 60.Subpart DA: Standards of Performance for New Stationary Sources. Standards of performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978. This is an appropriate rule.

BRIEF DESCRIPTION OF PROPERTY
The property is described as:

This facility has four thermally efficient heat recovery steam generators (HRSGs) and two steam turbines. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

Is an adequate description and purpose of the property provided? Does it list the anticipated environmental benefits? Are sketches and flow diagrams provided if needed?

An adequate description of the property was provided, and the purpose of the property was listed. The anticipated environmental benefit is listed. Sketches and flow diagrams were provided.

DECISION FLOWCHART(30 TAC 17.15(a))
Mark the appropriate boxes: Box 3 Box 5 Box 6(IV) Y Box 10(III) Box 12(I) Box 13(II)
PART B DECISION FLOWCHART (17.15(b))
Mark the appropriate boxes: Box 1Y Box 2 Y Box 3 Y

Describe how the property flowed through the Decision Flowchart:

Since the property is listed on Part B of the Equipment & Categories List this property leaves the Decision Flow Chart at Box 6. It passes through Box 1 of the Part B Decision Flow Chart with a yes answer. The use of this property at a combined cycle plant, as opposed to having a simple

cycle plant, provides an environmental benefit of reduced NOx emissions at the site. So there is a Yes answer for Box 2. Since there is a reduction in NOx emissions there is an environmental rule which is being met so there is a yes answer to Box 3. The steam turbine passes through Box 1 on the Part B Decision Flow Chart with a yes answer. Since the use of the steam turbine does not provide an environmental benefit at the site a no answer is the result of Box 2. The steam turbine is not eligible for a positive determination.

TIER III or IV APPLICATIONS

Does your calculation agree with the applicants?

No. The application contains a proposed formula for calculating the pollution control value of the HRSGs and the steam turbine. The formula is outcome determinative, and its focus is not on the pollution control aspect of the property. The Executive Director disagrees with this formula.

PROPERTY CATEGORIES AND COSTS

Is the table completed correctly? Has the applicant certified that all listed property became taxable for the first time after January 1, 1994? Is all information necessary for conducting the technical review included.

The table was completed correctly. The applicant certified that all listed property became taxable for the first time after January 1, 1994. All the information necessary for conducting the technical review was included on the application.

TECHNICAL DEFICIENCIES

Is the application complete as received: Y If the application was not administratively complete explain below when justifying the final decision in the final determination section. If the application was not technically complete then:

Provide the language to be used in the Notice of Deficiency (NOD) letter:

Summarize the NOD response:

Provide the language used in the second NOD letter:

Summarize the second NOD response:

Provide the language used in the thied NOD letter:

Summarize the third NOD response:

FINAL DETERMINATION

If the property description has been summarized enter the detailed property description:

This facility has four thermally efficient heat recovery steam generators (HRSGs) and two steam

turbines. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

Provide the reason for your final determination:

The Heat Recovery Steam Generators meet all of the requirements of Chapter 17. A positive use determination based on the most appropriate formula should be issued for the Heat Recovery Steam Generators. The most appropriate formula has been determined by the Executive Director. A negative determination should be issued for the steam turbine. The use of the steam turbine does not result in there being an environmental benefit at the site.

Provide the language for the final determination.

A positive use determination of 100% for the four Heat Recovery Steam Generators. A negative determination is issued for the steam turbine. The use of the steam turbine does not provide an environmental benefit at the site. The steam turbine is not considered to be pollution control equipment.

Highlight the required signatures and establish the appropriate due dates.

Reviewed: [illegible] **Date Signed:** 5/1/08

Peer Reviewed: Gary McCrotten **Date Signed:** 5-1-08

Team Leader: [illegible] **Date Signed:** 5/1/08

Section Manager: [illegible] **Date Signed:** MAY 1 2008

Division Director: [illegible] **Date Signed:** MAY 1 2008

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

May 1, 2008

OCT 10 2012

DUFF & PHELPS LLC
GREG MAXIM
919 CONGRESS #1450
AUSTIN, TX 78701

This letter is to inform you that on 5/1/2008, the technical review of Use Determination Application 07-11926 was completed. This application is for:

NAVASOTA WHARTON ENERGY PARTNERS LP
COLORADO BEND
3821 S STATE HWY 60
WHARTON, TX 77488

The use determination is included with this letter. In order to request an exemption, a copy of this Use Determination, along with a completed exemption request form #50-248 (can be found at www.cpa.state.tx.us), must be provided to the Chief Appraiser of the appropriate appraisal district. This request must be made by April 30.

House Bill 3121, enacted during the 77th Legislative Session, established a process for appealing a use determination. The Texas Commission on Environmental Quality (TCEQ) rules that implement the appeals process are at 30 TAC 17.25. Pursuant to 17.25(a)(1), an appeal must be filed within 20 days of receipt of the use determination. Should you choose to appeal the use determination, please submit a copy of your appeal to the TCEQ Tax Relief for Pollution Control Property program at the time of filing the appeal with the Chief Clerk of the commission.

If you have any questions or require any additional information, please contact the Tax Relief for Pollution Control Property Program at (512) 239-3100.

Sincerely,

David Greer
Team Leader, Pollution Prevention

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

USE DETERMINATION

The Texas Commission on Environmental Quality has reviewed Use Determination Application, 07-11926, filed by:

NAVASOTA WHARTON ENERGY PARTNERS LP
COLORADO BEND
3821 S STATE HWY 60
WHARTON TX 77488

The pollution control property/project listed in the Use Determination Application is:

This facility has four thermally efficient heat recovery steam generators (HRSGs) and two steam turbines. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

The outcome of the review is:

A 100% positive use determination for the four Heat Recovery Steam Generators. This equipment is considered to be pollution control equipment and was installed to meet or exceed federal or state regulations.

A negative determination is issued for the two steam turbines. The use of the steam turbines does not provide an environmental benefit at the site. The steam turbines are not considered to be pollution control equipment.

Executive Director

May. 1. 2008
Date

TAX RELIEF FOR POLLUTION CONTROL PROPERTY: TECHNICAL REVIEW DOCUMENT

Reviewed By: RLH App. No.: 07 - 11926 Review Start Date: 4/8/2008

Company Name: NAVASOTA WHARTON ENERGY PARTNERS LP
Facility Name: COLORADO BEND
County: WHARTON Outstanding Fees: N
Batch/Voucher Number:B500028

ADMINISTRATIVE REVIEW

Administrative Complete Date:4/8/2008

TIER LEVEL
What Tier is this application? The application was filed as a Tier IV application. Is this the appropriate level?

The property listed on this application, Heat Recovery Steam Generators and a steam turbine are items B8 and B10 on the Equipment and Categories List. This application was filed as a Tier IV. Tier IV is the appropriate level for this application.

RELEVANT RULE, REGULATION, OR STATUTORY PROVISION
The rule listed in the application is: 40 CFR 60.44Da
The appropriate rule is: 40 CFR 60.44Da

Explain why this is the appropriate rule?

40 CFR 60.Subpart DA: Standards of Performance for New Stationary Sources. Standards of performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978. This is an appropriate rule.

BRIEF DESCRIPTION OF PROPERTY
The property is described as:

This facility has four thermally efficient heat recovery steam generators (HRSGs) and two steam turbines. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

Is an adequate description and purpose of the property provided? Does it list the anticipated environmental benefits? Are sketches and flow diagrams provided if needed?

An adequate description of the property was provided, and the purpose of the property was listed. The anticipated environmental benefit is listed. Sketches and flow diagrams were provided.

DECISION FLOWCHART(30 TAC 17.15(a))
Mark the appropriate boxes: Box 3 Box 5 Box 6(IV) Y Box 10(III) Box 12(I) Box 13(II)
PART B DECISION FLOWCHART (17.15(b))
Mark the appropriate boxes: Box 1Y Box 2 Y Box 3 Y

Describe how the property flowed through the Decision Flowchart:

The Heat Recovery Steam Generators (HRSGs) are listed on Part B of the Equipment & Categories List as item B-8. As Part B equipment the HRSGs leave the Decision Flow Chart at Box 6 and pass through Box 1 of the Part B Decision Flow Chart with a yes answer. Since the use

of HRSGs provide an environmental benefit of reduced NOx emissions at the site there is a yes answer for Box 2. Since there is a reduction in NOx emissions there is an environmental rule which is being met, so there is a yes answer to Box 3. The steam turbine passes through Box 1 on the Part B Decision Flow Chart with a yes answer. Since the use of the steam turbine does not provide an environmental benefit at the site a no answer is the result of Box 2. The steam turbine is not eligible for a positive determination.

TIER III or IV APPLICATIONS

Does your calculation agree with the applicants?

No. The application contains a proposed formula for calculating the pollution control value of the HRSGs and the steam turbine. The formula is outcome determinative, and its focus is not on the pollution control aspect of the property. The Executive Director disagrees with this formula.

PROPERTY CATEGORIES AND COSTS

Is the table completed correctly? Has the applicant certified that all listed property became taxable for the first time after January 1, 1994? Is all information necessary for conducting the technical review included.

The table was completed correctly. The applicant certified that all listed property became taxable for the first time after January 1, 1994. All the information necessary for conducting the technical review was included on the application.

TECHNICAL DEFICIENCIES

Is the application complete as received: Y If the application was not administratively complete explain below when justifying the final decision in the final determination section. If the application was not technically complete then:

Provide the language to be used in the Notice of Deficiency (NOD) letter:

Summarize the NOD response:

Provide the language used in the second NOD letter:

Summarize the second NOD response:

Provide the language used in the thied NOD letter:

Summarize the third NOD response:

FINAL DETERMINATION

If the property description has been summarized enter the detailed property description:

This facility has four thermally efficient heat recovery steam generators (HRSGs) and two steam

turbines. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

Provide the reason for your final determination:

The Heat Recovery Steam Generators meet all of the requirements of Chapter 17. A positive use determination based on the most appropriate formula should be issued for the Heat Recovery Steam Generators. The most appropriate formula has been determined by the Executive Director. A negative determination should be issued for the steam turbine. The use of the steam turbine does not result in there being an environmental benefit at the site.

Provide the language for the final determination.

A positive use determination of 100% for the four Heat Recovery Steam Generators. A negative determination is issued for the steam turbine. The use of the steam turbine does not provide an environmental benefit at the site. The steam turbine is not considered to be pollution control equipment.

Highlight the required signatures and establish the appropriate due dates.

Reviewed: Ronald Holt **Date Signed:** 5/1/08

Peer Reviewed: Gary McAuliffe **Date Signed:** 5-1-08

Team Leader: [illegible] **Date Signed:** 5/1/08

Section Manager: [illegible] **Date Signed:** MAY 1 2008

Division Director: [illegible] **Date Signed:** MAY 1 2008

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

May 1, 2008

STATE OF TEXAS
COUNTY OF
OCT 10 2012

TENASKA INC
DAVID D JOHNSON
1044 N 115 ST #400
OMAHA, NE 68154 4446

This letter is to inform you that on 5/1/2008, the technical review of Use Determination Application 07-11914 was completed. This application is for:

TENASKA GATEWAY PARTNERS LTD
TENASKA GATEWAY GENERATION STATION
SH 315, PO BOX 697
MOUNT ENTERPRISE, TX 75681 0697

The use determination is included with this letter. In order to request an exemption, a copy of this Use Determination, along with a completed exemption request form #50-248 (can be found at www.cpa.state.tx.us), must be provided to the Chief Appraiser of the appropriate appraisal district. This request must be made by April 30.

House Bill 3121, enacted during the 77th Legislative Session, established a process for appealing a use determination. The Texas Commission on Environmental Quality (TCEQ) rules that implement the appeals process are at 30 TAC 17.25. Pursuant to 17.25(a)(1), an appeal must be filed within 20 days of receipt of the use determination. Should you choose to appeal the use determination, please submit a copy of your appeal to the TCEQ Tax Relief for Pollution Control Property program at the time of filing the appeal with the Chief Clerk of the commission.

If you have any questions or require any additional information, please contact the Tax Relief for Pollution Control Property Program at (512) 239-3100.

Sincerely,

David Greer
Team Leader, Pollution Prevention

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

USE DETERMINATION

The Texas Commission on Environmental Quality has reviewed Use Determination Application, 07-11914, filed by:

TENSKA GATEWAY PARTNERS LTD
TENASKA GATEWAY GENERATION STATION
SH 315, PO BOX 697
MOUNT ENTERPRISE TX 75681

The pollution control property/project listed in the Use Determination Application is:

This facility has three combustion turbine generators coupled with three thermally efficient heat recovery steam generators (HRSGs) and one enhanced steam turbine. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

The outcome of the review is:

A 100% positive use determination for the three Heat Recovery Steam Generators. This equipment is considered to be pollution control equipment and was installed to meet or exceed federal or state regulations.

A negative determination is issued for the steam turbine. The use of the steam turbine does not provide an environmental benefit at the site. The steam turbine is not considered to be pollution control equipment.

Executive Director

May. 1. 2008
Date

TAX RELIEF FOR POLLUTION CONTROL PROPERTY: TECHNICAL REVIEW DOCUMENT

Reviewed By: RLH App. No.: 07 - 11914 Review Start Date: 4/8/2008

Company Name: TENSKA GATEWAY PARTNERS LTD
Facility Name: TENASKA GATEWAY GENERATION STATION
County: RUSK Outstanding Fees: N
Batch/Voucher Number:B99788

ADMINISTRATIVE REVIEW

Administrative Complete Date:4/8/2008

TIER LEVEL
What Tier is this application? The application was filed as a Tier IV application. Is this the appropriate level?

The property listed on this application, Heat Recovery Steam Generators and a steam turbine are items B8 and B10 on the Equipment and Categories List. This application was filed as a Tier IV. Tier IV is the appropriate level for this application.

RELEVANT RULE, REGULATION, OR STATUTORY PROVISION
The rule listed in the application is: 40 CFR 60.44Da
The appropriate rule is: 40 CFR 60.44Da

Explain why this is the appropriate rule?

40 CFR 60.Subpart DA: Standards of Performance for New Stationary Sources. Standards of performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978. This is an appropriate rule.

BRIEF DESCRIPTION OF PROPERTY
The property is described as:

This facility has three combustion turbine generators coupled with three thermally efficient heat recovery steam generators (HRSGs). This application is a Tier IV application seeking a partial use determination for the three HRSGs and the enhanced steam turbines. To generate the equivalent amount of power using combustion turbine they would have needed to install a Selective Catalytic Reduction System.The application requests a partial determination.

Is an adequate description and purpose of the property provided? Does it list the anticipated environmental benefits? Are sketches and flow diagrams provided if needed?

An adequate description of the property was provided, and the purpose of the property was listed. The anticipated environmental benefit is listed. Sketches and flow diagrams were provided.

DECISION FLOWCHART(30 TAC 17.15(a))
Mark the appropriate boxes: Box 3 Box 5 Box 6(IV) Y Box 10(III) Box 12(I) Box 13(II)
PART B DECISION FLOWCHART (17.15(b))
Mark the appropriate boxes: Box 1Y Box 2 Y Box 3 Y

Describe how the property flowed through the Decision Flowchart:

The Heat Recovery Steam Generators (HRSGs) are listed on Part B of the Equipment &

Categories List as item B-8. As Part B equipment the HRSGs leave the Decision Flow Chart at Box 6 and pass through Box 1 of the Part B Decision Flow Chart with a yes answer. Since the use of HRSGs provide an environmental benefit of reduced NOx emissions at the site there is a yes answer for Box 2. Since there is a reduction in NOx emissions there is an environmental rule which is being met, so there is a yes answer to Box 3. The steam turbine passes through Box 1 on the Part B Decision Flow Chart with a yes answer. Since the use of the steam turbine does not provide an environmental benefit at the site a no answer is the result of Box 2. The steam turbine is not eligible for a positive determination.

TIER III or IV APPLICATIONS

Does your calculation agree with the applicants?

No. The application contains a proposed formula for calculating the pollution control value of the HRSGs and the steam turbine. The formula is outcome determinative, and its focus is not on the pollution control aspect of the property. The Executive Director disagrees with this formula.

PROPERTY CATEGORIES AND COSTS

Is the table completed correctly? Has the applicant certified that all listed property became taxable for the first time after January 1, 1994? Is all information necessary for conducting the technical review included.

The table was completed correctly. The applicant certified that all listed property became taxable for the first time after January 1, 1994. All the information necessary for conducting the technical review was included on the application.

TECHNICAL DEFICIENCIES

Is the application complete as received: Y If the application was not administratively complete explain below when justifying the final decision in the final determination section. If the application was not technically complete then:

Provide the language to be used in the Notice of Deficiency (NOD) letter:

Summarize the NOD response:

Provide the language used in the second NOD letter:

Summarize the second NOD response:

Provide the language used in the thied NOD letter:

Summarize the third NOD response:

FINAL DETERMINATION

If the property description has been summarized enter the detailed property description:

This facility has three combustion turbine generators coupled with three thermally efficient heat recovery steam generators (HRSGs). This application is a Tier IV application seeking a partial use determination for the three HRSGs and the enhanced steam turbines. To generate the equivalent amount of power using combustion turbine they would have needed to install a Selective Catalytic Reduction System.The application requests a partial determination.

Provide the reason for your final determination:

The Heat Recovery Steam Generators meet all of the requirements of Chapter 17. A positive use determination based on the most appropriate formula should be issued for the Heat Recovery Steam Generators. The most appropriate formula has been determined by the Executive Director. A negative determination should be issued for the steam turbine. The use of the steam turbine does not result in there being an environmental benefit at the site.

Provide the language for the final determination.

A positive use determination of 100% for the three Heat Recovery Steam Generators. A negative determination is issued for the steam turbine. The use of the steam turbine does not provide an environmental benefit at the site. The steam turbine is not considered to be pollution control equipment.

Highlight the required signatures and establish the appropriate due dates.

Reviewed: Ronald Katbetts **Date Signed:** 5/1/2008

Peer Reviewed: Gary McArthur **Date Signed:** 5/1/2008

Team Leader: [illegible] **Date Signed:** 5/1/08

Section Manager: [illegible] **Date Signed:** MAY 1 2008

Division Director: [illegible] **Date Signed:** MAY 1 2008

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

May 1, 2008

STATE OF TEXAS
COUNTY OF TRAVIS
OCT 10 2012

DUFF & PHELPS LLC
DENNIS DEEGEAR
919 CONGRESS #1450
AUSTIN, TX 78701

This letter is to inform you that on 5/1/2008, the technical review of Use Determination Application 07-11971 was completed. This application is for:

BORGER ENERGY ASSOCIATES LP
BORGER ENERGY BLACKHAWK STATION
119 N. SPUR CO-GEN PLACE
BORGER, TX 79008

The use determination is included with this letter. In order to request an exemption, a copy of this Use Determination, along with a completed exemption request form #50-248 (can be found at www.cpa.state.tx.us), must be provided to the Chief Appraiser of the appropriate appraisal district. This request must be made by April 30.

House Bill 3121, enacted during the 77th Legislative Session, established a process for appealing a use determination. The Texas Commission on Environmental Quality (TCEQ) rules that implement the appeals process are at 30 TAC 17.25. Pursuant to 17.25(a)(1), an appeal must be filed within 20 days of receipt of the use determination. Should you choose to appeal the use determination, please submit a copy of your appeal to the TCEQ Tax Relief for Pollution Control Property program at the time of filing the appeal with the Chief Clerk of the commission.

If you have any questions or require any additional information, please contact the Tax Relief for Pollution Control Property Program at (512) 239-3100.

Sincerely,

David Greer
Team Leader, Pollution Prevention

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

USE DETERMINATION

The Texas Commission on Environmental Quality has reviewed Use Determination Application, 07-11971, filed by:

BORGER ENERGY ASSOCIATES LP
BORGER ENERGY BLACKHAWK STATION
119 N. SPUR CO-GEN PLACE
BORGER TX 79008

The pollution control property/project listed in the Use Determination Application is:

This facility has two thermally efficient heat recovery steam generators (HRSGs). This application is a Tier IV application seeking a partial use determination for the two HRSGs.

The outcome of the review is:

A 100% positive use determination for the two Heat Recovery Steam Generators. This equipment is considered to be pollution control equipment and was installed to meet or exceed federal or state regulations.

Executive Director

May 2 2008
Date

TAX RELIEF FOR POLLUTION CONTROL PROPERTY: TECHNICAL REVIEW DOCUMENT

Reviewed By: RLH App. No.: 07 - 11971 Review Start Date: 4/8/2008

Company Name: BORGER ENERGY ASSOCIATES LP
Facility Name: BORGER ENERGY BLACKHAWK STATION
County: HUTCHINSON Outstanding Fees: N
Batch/Voucher Number:B500156

ADMINISTRATIVE REVIEW

Administrative Complete Date:4/8/2008

TIER LEVEL
What Tier is this application? The application was filed as a Tier IV application. Is this the appropriate level?

The property listed on this application, Heat Recovery Steam Generators, is item B8 on the Equipment and Categories List. This application was filed as a Tier IV. Tier IV is the appropriate level for this application.

RELEVANT RULE, REGULATION, OR STATUTORY PROVISION
The rule listed in the application is: 40 CFR 60.44Da
The appropriate rule is: 40 CFR 60.44Da

Explain why this is the appropriate rule?

40 CFR 60.Subpart DA: Standards of Performance for New Stationary Sources. Standards of performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978. This is an appropriate rule.

BRIEF DESCRIPTION OF PROPERTY
The property is described as:

This facility has two thermally efficient heat recovery steam generators (HRSGs). This application is a Tier IV application seeking a partial use determination for the two HRSGs.

Is an adequate description and purpose of the property provided? Does it list the anticipated environmental benefits? Are sketches and flow diagrams provided if needed?

An adequate description of the property was provided, and the purpose of the property was listed. The anticipated environmental benefit is listed. Sketches and flow diagrams were provided.

DECISION FLOWCHART(30 TAC 17.15(a))
Mark the appropriate boxes: Box 3 Box 5 Box 6(IV) Y Box 10(III) Box 12(I) Box 13(II)
PART B DECISION FLOWCHART (17.15(b))
Mark the appropriate boxes: Box 1Y Box 2 Y Box 3 Y

Describe how the property flowed through the Decision Flowchart:

Since the property is listed on Part B of the Equipment & Categories List this property leaves the Decision Flow Chart at Box 6. It passes through Box 1 of the Part B Decision Flow Chart with a yes answer. The use of this property at a combined cycle plant, as opposed to having a simple cycle plant, provides an environmental benefit of reduced NOx emissions at the site. So there is a

Yes answer for Box 2, Since there is a reduction in NOx emissions there is an environmental rule which is being met so there is a yes answer to Box 3.

TIER III or IV APPLICATIONS

Does your calculation agree with the applicants?

No. The application contains a proposed formula for calculating the pollution control value of the HRSGs and the steam turbine. The formula is outcome determinative, and its focus is not on the pollution control aspect of the property. The Executive Director disagrees with this formula.

PROPERTY CATEGORIES AND COSTS

Is the table completed correctly? Has the applicant certified that all listed property became taxable for the first time after January 1, 1994? Is all information necessary for conducting the technical review included.

The table was completed correctly. The applicant certified that all listed property became taxable for the first time after January 1, 1994. All the information necessary for conducting the technical review was included on the application.

TECHNICAL DEFICIENCIES

Is the application complete as received: Y If the application was not administratively complete explain below when justifying the final decision in the final determination section. If the application was not technically complete then:

Provide the language to be used in the Notice of Deficiency (NOD) letter:

Summarize the NOD response:

Provide the language used in the second NOD letter:

Summarize the second NOD response:

Provide the language used in the thied NOD letter:

Summarize the third NOD response:

FINAL DETERMINATION

If the property description has been summarized enter the detailed property description:

This facility has two thermally efficient heat recovery steam generators (HRSGs). This application is a Tier IV application seeking a partial use determination for the two HRSGs.

Provide the reason for your final determination:

The Heat Recovery Steam Generators meet all of the requirements of Chapter 17. A positive use determination based on the most appropriate formula should be issued for the Heat Recovery Steam Generators. The most appropriate formula has been determined by the Executive Director.

Provide the language for the final determination.

A positive use determination of 100% for the two Heat Recovery Steam Generators.

Highlight the required signatures and establish the appropriate due dates.

Reviewed: Randd Hatlett **Date Signed:** 5/1/08

Peer Reviewed: Gary McArthur **Date Signed:** 5-1-08

Team Leader: [signature] **Date Signed:** 5/1/08

Section Manager: [signature] **Date Signed:** MAY 1 2008

Division Director: [signature] **Date Signed:** MAY 1 2008

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

STATE OF TEXAS
OCT 10 2012

May 1, 2008

CALPINE/DOW
JUSTIN HYLAND/LEO SCHERRER
717 TEXAS AVE
HOUSTON, TX 77002

This letter is to inform you that on 5/1/2008, the technical review of Use Determination Application 07-11994 was completed. This application is for:

FREEPORT ENERGY CENTER LP
FREEPORT ENERGY CENTER LP
2301 N BRAZOSPORT BLVD
FREEPORT, TX 77451

The use determination is included with this letter. In order to request an exemption, a copy of this Use Determination, along with a completed exemption request form #50-248 (can be found at www.cpa.state.tx.us), must be provided to the Chief Appraiser of the appropriate appraisal district. This request must be made by April 30.

House Bill 3121, enacted during the 77th Legislative Session, established a process for appealing a use determination. The Texas Commission on Environmental Quality (TCEQ) rules that implement the appeals process are at 30 TAC 17.25. Pursuant to 17.25(a)(1), an appeal must be filed within 20 days of receipt of the use determination. Should you choose to appeal the use determination, please submit a copy of your appeal to the TCEQ Tax Relief for Pollution Control Property program at the time of filing the appeal with the Chief Clerk of the commission.

If you have any questions or require any additional information, please contact the Tax Relief for Pollution Control Property Program at (512) 239-3100.

Sincerely,

David Greer
Team Leader, Pollution Prevention

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

USE DETERMINATION

The Texas Commission on Environmental Quality has reviewed Use Determination Application, 07-11994, filed by:

FREEPORT ENERGY CENTER LP
FREEPORT ENERGY CENTER LP
2301 N BRAZOSPORT BLVD
FREEPORT TX 77451

The pollution control property/project listed in the Use Determination Application is:

This facility has thermally efficient heat recovery steam generators (HRSGs) and steam turbines. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

The outcome of the review is:

A 100% positive use determination for the Heat Recovery Steam Generators. This equipment is considered to be pollution control equipment and was installed to meet or exceed federal or state regulations.

A negative determination is issued for the steam turbines. The use of the steam turbines does not provide an environmental benefit at the site. The steam turbines are not considered to be pollution control equipment.

Executive Director

May 1 2008
Date

TAX RELIEF FOR POLLUTION CONTROL PROPERTY: TECHNICAL REVIEW DOCUMENT

Reviewed By: RLH App. No.: 07 - 11994 Review Start Date: 4/8/2008

Company Name: FREEPORT ENERGY CENTER LP
Facility Name: FREEPORT ENERGY CENTER LP
County: BRAZORIA Outstanding Fees: N
Batch/Voucher Number:B500289

ADMINISTRATIVE REVIEW

Administrative Complete Date:4/8/2008

TIER LEVEL
What Tier is this application? The application was filed as a Tier IV application. Is this the appropriate level?

The property listed on this application, Heat Recovery Steam Generators and a steam turbine are items B8 and B10 on the Equipment and Categories List. This application was filed as a Tier IV. Tier IV is the appropriate level for this application.

RELEVANT RULE, REGULATION, OR STATUTORY PROVISION
The rule listed in the application is: 40 CFR 60.44Da
The appropriate rule is: 40 CFR 60.44Da

Explain why this is the appropriate rule?

40 CFR 60.Subpart DA: Standards of Performance for New Stationary Sources. Standards of performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978. This is an appropriate rule.

BRIEF DESCRIPTION OF PROPERTY
The property is described as:

This facility has thermally efficient heat recovery steam generators (HRSGs) and steam turbines. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

Is an adequate description and purpose of the property provided? Does it list the anticipated environmental benefits? Are sketches and flow diagrams provided if needed?

An adequate description of the property was provided, and the purpose of the property was listed. The anticipated environmental benefit is listed. Sketches and flow diagrams were provided.

DECISION FLOWCHART(30 TAC 17.15(a))
Mark the appropriate boxes: Box 3 Box 5 Box 6(IV) Y Box 10(III) Box 12(I) Box 13(II)
PART B DECISION FLOWCHART (17.15(b))
Mark the appropriate boxes: Box 1Y Box 2 Y Box 3 Y

Describe how the property flowed through the Decision Flowchart:

Since the property is listed on Part B of the Equipment & Categories List this property leaves the Decision Flow Chart at Box 6. It passes through Box 1 of the Part B Decision Flow Chart with a yes answer. The use of this property at a combined cycle plant, as opposed to having a simple

cycle plant, provides an environmental benefit of reduced NOx emissions at the site. So there is a Yes answer for Box 2. Since there is a reduction in NOx emissions there is an environmental rule which is being met so there is a yes answer to Box 3. The steam turbine passes through Box 1 on the Part B Decision Flow Chart with a yes answer. Since the use of the steam turbine does not provide an environmental benefit at the site a no answer is the result of Box 2. The steam turbine is not eligible for a positive determination.

TIER III or IV APPLICATIONS

Does your calculation agree with the applicants?

No. The application contains a proposed formula for calculating the pollution control value of the HRSGs and the steam turbine. The formula is outcome determinative, and its focus is not on the pollution control aspect of the property. The Executive Director disagrees with this formula.

PROPERTY CATEGORIES AND COSTS

Is the table completed correctly? Has the applicant certified that all listed property became taxable for the first time after January 1, 1994? Is all information necessary for conducting the technical review included.

The table was completed correctly. The applicant certified that all listed property became taxable for the first time after January 1, 1994. All the information necessary for conducting the technical review was included on the application.

TECHNICAL DEFICIENCIES

Is the application complete as received: Y If the application was not administratively complete explain below when justifying the final decision in the final determination section. If the application was not technically complete then:

Provide the language to be used in the Notice of Deficiency (NOD) letter:

Summarize the NOD response:

Provide the language used in the second NOD letter:

Summarize the second NOD response:

Provide the language used in the thied NOD letter:

Summarize the third NOD response:

FINAL DETERMINATION

If the property description has been summarized enter the detailed property description:

This facility has thermally efficient heat recovery steam generators (HRSGs) and steam turbines.

This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

Provide the reason for your final determination:

The Heat Recovery Steam Generators meet all of the requirements of Chapter 17. A positive use determination based on the most appropriate formula should be issued for the Heat Recovery Steam Generators. The most appropriate formula has been determined by the Executive Director. A negative determination should be issued for the steam turbine. The use of the steam turbine does not result in there being an environmental benefit at the site.

Provide the language for the final determination.

A positive use determination of 100% for the Heat Recovery Steam Generators. A negative determination is issued for the steam turbine. The use of the steam turbine does not provide an environmental benefit at the site. The steam turbine is not considered to be pollution control equipment.

Highlight the required signatures and establish the appropriate due dates.

Reviewed: [signature] **Date Signed:** 5/1/8

Peer Reviewed: [signature] **Date Signed:** 5-1-08

Team Leader: [signature] **Date Signed:** 5/1/08

Section Manager: [signature] **Date Signed:** MAY 1 2008

Division Director: [signature] **Date Signed:** MAY 1 2008

Attachment C

BEPC's Revised Calculation Supporting a
Partial Use Determination of 64.29%

Attachment C, Revised Calculation to Correct Capital Recovery Factor in Calculation of LCOE

TCEQ Use Determi: Application Section 11 use:
Company: Brai ric Power Cooperative, Inc.
Plant: Johnson County Generation Facility
Unit: 258 MW 1 x 1 Configuration Combined Cycle Power Plant (1996)
Address: Cleburne, Texas
Project: Tier III Cost Analysis Procedure
Date: 10-Feb-12

I. Assumptions

Pollution Control Property (PC)		Source
Property Cost:	$28,111,986.00	BEC Acctng
Capital Cost ($/KW):	$326.88	PC/TC
Total Capacity (MW):	258	∑(CT+ST)
CT Capacity (MW)	172	BEC 2010 RUS Form 12
ST Capacity (MW)	86	BEC 2010 RUS Form 12
2010 Net Annual ST Generation Capacity (KWhr):	487,215,000	BEC 2010 RUS Form 12
2010 Net Annual ST Generation Capacity (MWhr):	487,215	BEC 2010 RUS Form 12
2010 ST Capacity Factor:	64.67	Energy/(TC * 8760)
2010 Plant Heat Rate (btu/kwhr):	7,782	BEC 2010 RUS Form 12
2010 Plant Heat Rate (mmbtu/kwhr):	0.008	NPHR/1E06
2010 Operating Hours	7,606	BEC 2010 RUS Form 12
Capital Cost Old:	0	
Comparable Technology Cost:	0	
Comparable Technology:	0	
Design Capacity Factor:	0	
Capacity (MW):	1	

Conversion Factors	
Hrs/yr	8760
KW/MW	1000
lb/kg	2.2
s/hr	3600
btu/mmbtu	1000000

Economic Assumptions		Source
Discount Rate (%)	10.00%	Standard project rate
Periods (Yrs)	30	RUS depreciation
PC Property Fixed O&M Cost ($/KW-yr)	$6,126,060	BEC 2010 RUS Form 12
CT Fixed O&M Costs ($)	$4,084,040	Formula
ST Fixed O&M Costs ($)	$2,042,020	Formula
Fuel Cost ($/MMBTU)	$4.11	Note 1
PC property Variable Cost ($/MWh)	$5.00	Check with QSE
PC property Variable Cost ($/KWh)	$0.0050	Formula
ERCOT Electricity Pricing ($/MWh)	$44.48	Note 2
Interest Rate (%)	10.00%	

Note 1: Average cost for fuel (2009 - 2011) weighted by monthly steam turbine generation

Note 2: Average Settlement Point price for resource weighted by hourly steam turbine generation, reflected by North Load Zone Market Clearing Price for Energy (MCPE) for Jan 1, 2009 - Nov 30, 2010 and Real-time Resource

Levelized Cost of Energy (LCOE) Model Outputs	
Capitol Recovery Factor (%)	10.61%
LCOE ($/KWh)	0.03079

II. Cost Analysis Procedure

A. $$\frac{[(\text{Production Capacity Factor} \times \text{Capital Cost New}) - \text{Capital Cost Old} - \text{Marketable Product}]}{\text{Capital Cost New}}$$

B. Cost Analysis Procedure Formulas (TCEQ)

Partial Use Determination

$$\frac{[(\text{Production Capacity Factor} \times \text{Capital Cost New}) - \text{Capital Cost Old} - \text{Marketable Product Value}]}{\text{Capital Cost New}}$$

where: Marketable Product Value = $$\sum_{t=1}^{n} \frac{\text{Marketable Product Value} - \text{Production Cost}}{(1 + \text{Interest Rate})^n}$$

n = estimated useful life in years of years equipment
t = year one
Interest Rate = 10%

C. Cost Analysis Procedure for Pollution Control Property

Marketable Product Value = Electricity Price ($/MWh) x MWh per Year
Direct Cost of Production = Levelized Cost of Energy x KWh per Year

$$\text{LCOE ($/KWh)} = \frac{(\text{Capital Cost} \times \text{Capital Recovery Factor}) + \text{Fixed O\&M Costs}}{\text{Hours per Year} \times \text{Capcity Factor}} + (\text{Fuel Cost} \times \text{Heat Rate})$$

Capital Recovery Factor (CRF) $\frac{i \times (1+i)^n}{(1+i)^n - 1}$

(PC)	(CRF)		(Annual cost to carry)		(FOM)	(Total Annual FC)	
$28,111,986.00	10.61%	=	$2,982,098.34	+	$2,042,020	$5,024,118.34	
						$0.0103	/kWh
					(Fuel x NPHR)	$0.0320	
					LCOE:	$0.04229	($/kWh)

Attachme... C, cont'

Formula: $\frac{(PCF \times CCN) - CCO - NPVMP}{CCN}$

III. Cost Analysis Procedure Calculations For Johnson County HRSG

A. Marketable Product Value (MPV)

Electricity Price $\frac{\$}{MWh} \times \frac{\text{Plant MWh}}{\text{Year}}$ = ($) MPV

$44.48 x 487,215 = $21,671,323.20

B. Production Cost (PC)

Levelized Cost Of Energy (LCOE) $\frac{\$}{KWh} \times \frac{\text{Plant MWh}}{\text{Year}}$ = ($) PC

$0.04229 x 487,215,000 = $20,606,531.81

Net Present Value Marketable Product (NPVMP) Calculation

$\sum_{t=1}^{n} \frac{\text{Marketable Product Value - Production Cost}}{(1 + \text{Interest Rate})^n}$ = NPVMP ($)

$\sum_{t=1}^{n} \frac{\$21,671,323.20 - \$20,606,531.81}{1.10}$ = NPVMP $10,037,697.34

$10,037,697.34

If MP is <= 0, then MP = 0

C. Production Capacity Factor (PCF)

Production Capacity of Existing Equipment or Process / Production Capacity of New Equipment or Process = PCF

0 / 86 MW x 56.21% = PCF 1.00

D. Bapital Cost New (CCN)

Pollution Control Property (PC) = CCN $28,111,986.00

E. Capital Cost Old (CCO)

Comparable Technology = CCO $0.00

Partial Use Determination Calculation

$\frac{(PCF \times CCN) - CCO - MP}{CCN}$ = Partial Use Determination %

$\frac{\$28,111,986.00 - \$0.00 - \$10,037,697.34}{\$28,111,986.00}$ = 64.29%

Eligible HRSG Costs (Partial Use Determination % x PC Property) = $18,074,288.66

TCEQ Use Determination Application Section 11 use:	
Use Percent	64.29%
Estimated Dollar Value	$18,074,288.66

$1,064,791.39
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ERCOT NORTH

Quote Date
2/8/2012

Forward Prices ($/MWh)
(Long term model includes capacity)

Forward Month	On Peak (5x16)	7x8	2x16	Wrap	7x24
Feb-12	23.39	17.82	19.31	18.36	20.76
Mar-12	24.75	16.87	18.33	17.41	20.89
Apr-12	27.18	17.52	20.05	18.47	22.53
May-12	31.21	16.57	20.33	17.95	24.22
Jun-12	38.04	17.78	23.78	20.03	28.43
Jul-12	58.75	19.98	26.68	22.61	38.93
Aug-12	59.44	20.98	26.56	22.88	40.96
Sep-12	36.06	17.76	23.38	20.12	26.85
Oct-12	29.33	17.06	20.74	18.31	23.76
Nov-12	26.84	18.41	20.76	19.29	22.81
Dec-12	29.58	20.03	22.71	21.14	24.77
Jan-13	33.68	25.22	28.96	26.59	29.94
Feb-13	33.78	25.88	28.05	26.67	30.06
Mar-13	31.99	22.55	24.58	23.35	27.26
Apr-13	31.73	22.04	25.06	23.09	27.31
May-13	35.38	22.13	27.16	23.98	29.37
Jun-13	42.36	23.41	31.74	26.74	33.68
Jul-13	61.93	28.18	37.13	31.47	45.88
Aug-13	62.22	28.67	36.70	31.62	46.10
Sep-13	39.18	23.29	30.23	26.07	31.90
Oct-13	31.31	22.13	26.91	23.76	27.49
Nov-13	32.16	23.18	26.27	24.41	27.85
Dec-13	33.85	24.46	27.59	25.69	29.38
Jan-14	33.62	29.96	31.27	30.44	31.94
Feb-14	33.72	29.77	31.36	30.35	31.95
Mar-14	29.96	25.67	27.86	26.53	28.08
Apr-14	30.27	24.60	27.97	25.77	27.97
May-14	36.32	24.51	30.36	26.80	31.10
Jun-14	44.29	26.13	34.98	29.43	36.36
Jul-14	63.97	31.25	41.18	34.90	48.65
Aug-14	63.94	31.41	40.67	35.04	48.09
Sep-14	40.66	25.65	32.90	28.37	34.11
Oct-14	32.88	24.19	29.42	25.97	29.39
Nov-14	33.53	25.01	28.49	26.48	29.45
Dec-14	35.04	26.49	29.73	27.68	31.16
Jan-15	36.82	32.13	34.24	32.96	34.70
Feb-15	36.86	31.91	34.28	32.77	34.72
Mar-15	32.39	27.76	30.12	28.63	30.41
Apr-15	32.69	26.36	29.98	27.62	30.10

ERCOT NORTH

Quote Date
2/8/2012

Forward Prices ($/MWh)
(Long term model includes capacity)

Forward Month	On Peak (5x16)	7x8	2x16	Wrap	7x24
May-15	37.08	26.25	32.82	28.98	32.46
Jun-15	43.99	28.09	37.03	31.20	37.45
Jul-15	68.51	33.56	43.66	37.00	52.59
Aug-15	68.46	33.29	43.11	37.14	51.28
Sep-15	40.28	27.08	34.73	29.95	34.77
Oct-15	31.81	25.90	29.58	27.25	29.41
Nov-15	32.44	26.39	29.90	27.79	29.85
Dec-15	33.87	27.76	31.16	29.01	31.31
Jan-16	42.21	28.63	33.28	30.56	35.57
Feb-16	43.07	29.92	32.39	30.80	36.72
Mar-16	41.59	29.16	31.56	29.98	35.73
Apr-16	44.02	29.56	33.82	31.16	37.16
May-16	49.78	30.64	37.95	33.50	40.85
Jun-16	49.44	30.35	40.02	33.72	41.40
Jul-16	54.79	31.79	43.01	36.45	44.34
Aug-16	57.02	34.21	43.29	37.30	47.05
Sep-16	48.83	30.32	38.88	33.53	40.67
Oct-16	45.25	29.23	36.22	31.97	37.97
Nov-16	44.07	31.23	35.20	32.72	38.01
Dec-16	41.82	31.23	35.23	32.80	36.87
Jan-17	43.43	29.90	34.55	31.72	37.01
Feb-17	44.68	31.16	33.78	32.11	38.10
Mar-17	43.43	30.72	33.25	31.58	37.45
Apr-17	45.60	31.62	36.39	33.53	38.89
May-17	51.52	33.67	41.32	36.48	43.60
Jun-17	51.98	33.59	44.29	37.82	44.48
Jul-17	56.57	35.32	47.78	40.49	47.41
Aug-17	59.27	38.36	48.54	41.82	50.45
Sep-17	50.21	33.54	43.54	37.54	43.17
Oct-17	47.41	33.57	41.20	36.37	41.60
Nov-17	46.86	36.09	40.69	37.81	42.03
Dec-17	45.27	36.25	41.09	38.26	41.27
Jan-18	47.14	35.78	41.10	37.73	42.18
Feb-18	50.42	37.19	40.31	38.32	44.08
Mar-18	48.88	37.49	40.72	38.68	43.51
Apr-18	53.44	34.98	40.02	36.87	44.60
May-18	55.65	39.10	47.98	42.36	48.65
Jun-18	59.75	41.71	55.57	46.90	52.90
Jul-18	63.99	45.85	59.52	51.21	56.98

ERCOT NORTH

Quote Date
2/8/2012

Forward Prices ($/MWh)
(Long term model includes capacity)

Forward Month	On Peak (5x16)	7x8	2x16	Wrap	7x24
Aug-18	68.83	49.61	62.79	54.10	61.38
Sep-18	62.65	46.35	58.27	51.39	56.15
Oct-18	55.59	43.23	51.70	46.11	50.80
Nov-18	57.55	44.93	50.65	47.07	51.96
Dec-18	62.00	51.89	57.66	54.28	57.60
Jan-19	65.87	51.10	58.68	53.88	59.55
Feb-19	67.33	51.37	55.68	52.94	59.79
Mar-19	68.67	45.22	49.29	46.82	56.70
Apr-19	72.58	51.82	58.93	54.30	63.24
May-19	75.01	53.59	65.76	58.06	66.08
Jun-19	78.73	58.49	73.22	64.38	70.76
Jul-19	84.34	62.91	78.44	68.62	76.06
Aug-19	87.91	65.39	81.76	71.40	79.21
Sep-19	77.33	58.26	71.92	63.72	69.77
Oct-19	68.57	45.65	55.52	49.01	58.68
Nov-19	66.26	49.71	56.33	52.35	58.52
Dec-19	66.50	53.54	60.39	56.22	60.86
Jan-20	69.59	54.77	62.90	57.75	63.35
Feb-20	71.65	53.46	58.10	55.24	62.78
Mar-20	73.62	45.08	48.97	46.51	59.36
Apr-20	75.45	53.08	60.36	55.61	65.31
May-20	78.63	57.51	71.91	63.49	70.00
Jun-20	83.06	61.90	77.25	67.24	74.98
Jul-20	89.51	66.18	83.24	71.99	80.65
Aug-20	92.69	68.26	86.20	75.29	83.15
Sep-20	79.96	61.15	74.36	66.10	72.57
Oct-20	71.97	54.23	66.56	58.76	65.01
Nov-20	70.35	51.97	58.90	54.74	61.67
Dec-20	69.01	58.35	64.18	60.49	64.52
Jan-21	70.72	55.80	64.87	59.57	64.37
Feb-21	69.66	54.24	58.79	55.90	62.45
Mar-21	76.43	43.25	46.81	44.46	60.30
Apr-21	78.42	52.11	59.26	54.60	66.24
May-21	80.83	58.24	72.82	64.29	71.40
Jun-21	85.71	63.19	79.71	68.94	77.14
Jul-21	91.58	67.33	85.17	74.32	82.12
Aug-21	94.32	68.79	87.72	75.74	84.53
Sep-21	80.33	63.34	74.71	67.60	73.54
Oct-21	74.13	54.43	67.44	59.53	66.13

ERCOT NORTH

Quote Date
2/8/2012

Forward Prices ($/MWh)
(Long term model includes capacity)

Forward Month	On Peak (5x16)	7x8	2x16	Wrap	7x24
Nov-21	70.98	52.21	58.85	54.69	62.28
Dec-21	68.86	58.88	64.04	60.64	64.70
Jan-22	75.29	58.27	67.33	61.82	67.91
Feb-22	73.84	56.94	61.71	58.68	65.90
Mar-22	77.94	43.46	47.03	44.68	61.15
Apr-22	79.06	57.51	65.79	60.61	69.22
May-22	83.57	61.31	75.94	67.05	74.51
Jun-22	87.78	64.98	81.64	70.77	79.09
Jul-22	93.92	71.38	87.35	78.01	84.85
Aug-22	96.74	71.06	89.93	77.48	87.01
Sep-22	81.29	68.59	75.60	68.09	74.25
Oct-22	75.21	52.00	64.42	56.87	65.15
Nov-22	72.23	52.61	59.30	55.11	63.09
Dec-22	69.50	61.53	64.63	62.75	65.80
Jan-23	74.90	60.06	69.40	63.72	68.77
Feb-23	74.43	55.25	59.88	56.93	65.26
Mar-23	78.93	44.91	48.60	46.17	62.40
Apr-23	80.47	58.05	66.81	61.55	69.96
May-23	85.68	63.83	78.34	69.16	76.98
Jun-23	89.67	67.16	83.40	72.81	81.05
Jul-23	96.41	73.44	89.67	80.18	87.16
Aug-23	98.43	72.84	91.54	79.20	88.71
Sep-23	82.94	63.37	77.14	68.88	75.13
Oct-23	76.56	56.88	69.82	61.63	68.69
Nov-23	71.98	57.17	64.44	59.89	65.53
Dec-23	70.99	63.27	66.02	64.41	67.24
Jan-24	74.68	60.72	69.46	63.93	69.02
Feb-24	76.95	61.24	66.30	63.04	69.75
Mar-24	78.36	50.54	55.09	52.33	64.10
Apr-24	83.69	52.78	60.02	55.30	69.18
May-24	85.79	61.23	75.14	66.34	75.54
Jun-24	90.94	67.51	84.57	74.33	81.71
Jul-24	97.66	72.42	90.82	79.18	87.92
Aug-24	100.99	75.13	93.92	82.03	91.00
Sep-24	89.93	67.38	83.64	73.88	81.01
Oct-24	76.18	57.20	69.57	61.41	68.72
Nov-24	73.18	58.32	66.09	61.42	66.64
Dec-24	74.05	60.80	68.57	63.85	68.46
Jan-25	79.23	61.37	70.48	64.72	71.58

ERCOT NORTH

Quote Date
2/8/2012

Forward Prices ($/MWh)
(Long term model includes capacity)

Forward Month	On Peak (5x16)	7x8	2x16	Wrap	7x24
Feb-25	78.23	61.96	67.15	63.84	70.70
Mar-25	78.21	50.66	55.22	52.45	64.10
Apr-25	82.96	59.88	68.09	62.73	72.62
May-25	86.88	63.98	79.25	69.97	77.61
Jun-25	92.52	68.33	86.04	74.97	83.16
Jul-25	100.33	73.00	93.31	80.46	89.86
Aug-25	103.73	76.09	96.47	84.08	92.95
Sep-25	90.95	68.06	84.58	74.26	82.05
Oct-25	77.31	55.27	67.21	59.33	68.22
Nov-25	73.88	57.95	66.02	61.35	66.63
Dec-25	74.50	66.10	69.29	66.64	70.36
Jan-26	82.40	65.45	75.68	69.44	75.29
Feb-26	80.98	64.06	69.42	66.01	73.14
Mar-26	82.79	53.61	58.23	55.31	68.33
Apr-26	86.77	61.99	70.49	64.95	75.61
May-26	91.21	67.74	84.74	74.81	81.87
Jun-26	97.43	71.96	90.61	78.45	87.73
Jul-26	105.34	77.34	97.96	84.36	94.74
Aug-26	108.63	79.46	101.02	87.92	97.27
Sep-26	94.03	71.22	87.45	77.31	85.11
Oct-26	83.09	62.33	76.51	67.54	74.90
Nov-26	80.50	60.69	68.77	63.91	71.28
Dec-26	79.24	67.68	73.70	69.89	74.31
Jan-27	83.80	65.92	76.64	70.37	76.15
Feb-27	83.08	63.20	68.50	65.13	73.68
Mar-27	85.92	51.98	56.26	53.44	69.53
Apr-27	89.51	58.42	66.44	61.21	75.05
May-27	94.27	67.39	84.26	74.39	82.94
Jun-27	100.92	73.55	93.85	80.61	90.54
Jul-27	108.71	79.59	101.10	88.03	97.37
Aug-27	111.53	81.05	103.73	89.38	99.86
Sep-27	95.09	74.61	88.44	79.79	86.93

USDA United States Department of Agriculture
Rural Development Utilities Programs - Data Collection System

HOME HELP LOGOUT CONTACT US

CLIFTON KARNEI : MY BORROWERS : BRAZOS ELECTRIC POWER COOPERATIVE, INC. [TX0121]

NAVIGATION

My DCS
Borrowers
Profile

My DCS Borrowers

My Borrowers : Brazos Electric Power Cooperative, Inc. [TX0121]

Financial and Operating Report Electric Power Supply - Filing Frequency: Annual

Year	Year-to-Date	Status	Audited Data	Action
2010	December	Submitted [04/06/2011 04:39 PM]	Yes	View Edit ASR BSP Export
2009	December	Submitted [04/12/2010 01:29 PM]	Yes	View Edit ASR BSP Export
2008	December	Submitted [04/02/2009 02:41 PM]	Yes	View Edit ASR BSP Export
2007	December	Submitted [04/16/2008 04:02 PM]	Yes	View Edit ASR BSP Export
2006	December	Submitted [04/09/2007 09:16 AM]	No	View Edit ASR BSP Export
2005	December	Submitted [03/16/2005 12:16 PM]	N/A	View Edit ASR BSP Export
2004	December	Submitted [03/14/2005 03:46 PM]	N/A	View Edit ASR BSP Export
2003	December	Submitted [03/12/2004 10:20 AM]	N/A	View Edit ASR BSP Export
2002	December	Submitted [04/08/2003 02:15 PM]	N/A	View Edit ASR BSP Export

New Power Supply Operating Report

Audit

Year	Approval-Date	File Name	Status	Action
No Audit File				

Upload Audit

Users associated with the borrower

Name	Phone Number	Phone Extension	Email	Title	Is Active?	Role(s)
Birkes, Kay	254-750-6239		kbirkes@brazoselectric.com	Treasury/Property/Risk Accounting Superv	Yes	User
Bordovsky, Khaki	254-715-3014		kbordovsky@brazoselectric.com	VP Services	Yes	Administrator, User
Breton, Gina	254-749-0053		gbreton@brazoselectric.com	Accountant	Yes	User
Canada, Lola	254-750-6237		lcanada@brazoselectric.com	Secretary, VP Finance	Yes	User
Karnei, clifton	254-750-6600		ckarnei@brazoselectric.com	Exec VP & General Manager	Yes	Certifier, User
Kramolis, Timothy	254-750-6242		tkramolis@brazoselectric.com	Accountant	Yes	User
Pankonien, Kelly	254-750-6238		kpankonien@brazoselectric.com	Accountant, Budget & Rates	Yes	User
perkins, wesley	254-750-6532		dperkins@brazoselectric.com	General Accounting Supervisor	Yes	User

Version 2.0.4106.17075

USDA Rural Development

United States Department of Agriculture
Rural Development Utilities Programs - Data Collection System

HOME HELP PRINT LOGOUT CONTACT US

CLIFTON KARNEI : BRAZOS ELECTRIC POWER COOPERATIVE, INC. (TX0121) : FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY : DECEMBER 2010

NAVIGATION

- Reports
  - Op. Report-Power
  - Supply
    - Certification
    - Point Of Contact
    - Part a
      - Section A
      - Section B
      - Section C
    - Part b SE
    - Part b PP
    - Part c RE
    - Part c
    - Parts d-g
    - Part h
      - Section A
      - Section B
      - Section C
      - Section D
      - Section E
      - Section F
        - Sub Section I
        - Sub Section II
        - Sub Section III
        - Sub Section IV
      - Section G
      - Section H
      - Section I
      - Section J
      - Section K
      - Section L
    - Part i
      - Section A
      - Section B
      - Section C
      - Section D

Certification

Certification saved successfully.

This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C 552).

According to the Paperwork Reduction Act of 1995, an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The valid OMB control number for this information collection is 0572-0032. The time required to complete this information collection is estimated to average 25 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES

DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7CFR CHAPTER XVII
(check one of the following)

(●) All of the obligations under the RUS loan documents have been fulfilled in all material respects.

( ) There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part a Section C of this report.

(●) Share this data with NRUCFC.

( ) Do not share this data with NRUCFC.

Manager Name: clifton karnei
Manager Title: Exec VP & General Mana
Date Certified and Electronically Signed: 4/6/2011

(●) Certify ( ) Uncertify

Save

Version 2.0.4106.17075

(Rev. 12-05)

USDA United States Department of Agriculture
Rural Development Utilities Programs - Data Collection System

HOME HELP PRINT LOGOUT CONTACT US

CLIFTON KARNEI | BRAZOS ELECTRIC POWER COOPERATIVE, INC. [TX0121] | FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY : DECEMBER 2010

NAVIGATION

- Reports
  - Op. Report-Power
  - Supply
    - Certification
    - Point Of Contact
    - Part a
      - Section A
      - Section B
      - Section C
    - Part b SF
    - Part b PP
    - Part c RE
    - Part e
    - Parts d-g
    - Part h
      - Section A
      - Section B
      - Section C
      - Section D
      - Section E
      - Section F
        - Sub Section I
        - Sub Section II
        - Sub Section III
        - Sub Section IV
      - Section G
      - Section H
      - Section I
      - Section J
      - Section K
      - Section L
    - Part i
      - Section A
      - Section B
      - Section C
      - Section D

Certification

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We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES

DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7CFR CHAPTER XVII
(check one of the following)

◉ All of the obligations under the RUS loan documents have been fulfilled in all material respects.

○ There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part a Section C of this report.

◉ Share this data with NRUCFC.

○ Do not share this data with NRUCFC.

Manager Name: clifton karnei
Manager Title: Exec VP & General Mana
Date Certified and Electronically Signed: 4/6/2011

◉ Certify ○ Uncertify

Save

Version 2.0.4108.17076

(Rev. 12-05)

According to the Paperwork Reduction Act of 1995, an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The valid OMB control number for this information collection is 0572-0032. The time required to complete this information collection is estimated to average 31 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	BORROWER DESIGNATION TX0121 PERIOD ENDED December, 2010 (Prepared with Audited Dat BORROWER NAME Brazos Electric Power Cooperative, Inc.

INSTRUCTIONS - See help in the online application.

This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C. 552)

CERTIFICATION

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7 CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7 CFR CHAPTER XVII

(check one of the following)

[X] All of the obligations under the RUS loan documents have been fulfilled in all material respects.

[ ] There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part A Section C of this report.

clifton karnei

4/6/2011
DATE

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART F CC - COMBINED CYCLE PLANT

BORROWER DESIGNATION TX0121

PLANT Johnson County

PERIOD ENDED December, 2010

INSTRUCTIONS - See help in the online application.

SECTION A. COMBINED CYCLE GENERATING UNITS

NO.	UNIT NO. (a)	SIZE (kW) (b)	FUEL CONSUMPTION: OIL (1000 Gals.) (c)	GAS (1000 CF) (d)	OTHER (e)	TOTAL (f)	OPERATING HOURS: IN SERVICE (g)	ON STANDBY (h)	OUT OF SERVICE: SCHED. (i)	UNSC. (j)	GROSS GENER. (MWh) (k)	BTU PER kWh (l)
1.	2	172,000	0.00	7,437,976.00	0.00		7,606	123	873	158	974,427	
2.	2	86,000	0.00	3,718,986.00	0.00		7,606	123	873	158	487,215	
3.												
4.												
5.												
6.	Total	258,000	0.00	11,156,962.00	0.00		15,212	246	1,746	316	1,461,642	7,589.34
7.	Average BTU		0.00	994.12			Station Service (MWh)				36,313.00	
8.	Total BTU (10^6)		0.00	11,091,432.00		11,091,432.00	Net Generation (MWh)				1,425,329.00	7,781.66
9.	Total Del. Cost ($)		0.00	0.00	0.00		Station Service % Of Gross				2.48	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE	NO.	ITEM	VALUE
1.	No. Employees Full Time (Include. Superintendent)	1	5.	Maintenance Plant Payroll ($)	0
2.	No. Employees Part Time	0	6.	Other Accounts Plant Payroll ($)	0
3.	Total Employee Hours Worked	0	7.	Total Plant Payroll ($)	145232
4.	Operating Plant Payroll ($)	145232			

SECTION C. FACTORS & MAXIMUM DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	64.40%
2.	Plant Factor (%)	64.67%
3.	Running Plant Capacity Factor (%)	74.48%
4.	15 Min. Gross Max. Demand (kW)	
5.	Indicated Gross Max. Demand (kW)	259,083

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/$10^6$ BTU (c)
1.	Operation, Supervision and Engineering	500	223,000		
2.	Fuel, Oil	547.1	0		
3.	Fuel, Gas	547.2	49,610,121		4.47
4.	Fuel, Other	547.3	0		
5.	Energy for Compressed Air	547.4	0	0.00	
6.	Fuel SubTotal (2 thru 5)	547	49,610,121	34.80	4.47
7.	Generation Expenses	548	169,036		
8.	Miscellaneous Other Power Generation Expenses	549	1,313,249		
9.	Rents	507	0		
10.	Steam Expenses	502	526,272		
11.	Electric Expenses	505	0		
12.	Miscellaneous Steam Power Expenses	506	2,518,669		
13.	Allowances	509	0		
14.	Non-Fuel SubTotal (1 + 7 thru 13)		4,750,205	3.33	
15.	Operating Expense (6 + 14)		54,360,326	38.13	
16.	Maintenance, Supervision and Engineering	551, 510	0		
17.	Maintenance of Structures	552, 511	4,358		
18.	Maintenance of Generating and Electric Plant	553, 513	6,126,060		
19.	Maintenance of Miscellaneous Other Power Generating Plant	554, 514	70,111		
20.	Maintenance Expense (16 thru 19)		6,200,529	4.35	
21.	Total Production Expense (15 + 20)		60,560,855	42.48	
22.	Depreciation	403.4, 403.1, 411.10	6,505,589		
23.	Interest	427	14,000,732		
24.	Total Fixed Cost (22 + 23)		20,506,321	14.38	
25.	Power Cost (21 + 24)		81,067,176	56.87	

Remarks

	Jack 1 STG Weighted Avg. Gas (MMBtu)	Value Without Transportation	Average Monthly Cost	Heat Rate	Value With Transportation	Johnson STG Weighted Avg. Gas (MMBtu)	Value Without Transportation	Value With Transportation
Jan-09	956,361	$ 4,573,320.31	$ 34.39	7.19	$ 4,677,563.71	324,379	$ 1,551,181.78	$ 1,586,539.13
Feb-09	843,819	$ 2,892,612.77	$ 24.46	7.13	$ 3,019,185.67	234,291	$ 803,149.47	$ 838,293.12
Mar-09	912,676	$ 2,757,192.93	$ 21.60	7.15	$ 2,886,618.21	-	$ -	$ -
Apr-09	220,030	$ 733,578.69	$ 22.63	6.79	$ 785,725.70	-	$ -	$ -
May-09	801,279	$ 2,403,034.28	$ 21.95	7.32	$ 2,513,610.72	199,361	$ 597,882.50	$ 625,394.26
Jun-09	1,047,398	$ 3,290,925.77	$ 22.66	7.21	$ 3,416,613.58	395,940	$ 1,244,042.86	$ 1,291,555.64
Jul-09	1,175,097	$ 4,044,682.36	$ 24.92	7.24	$ 4,184,518.85	436,267	$ 1,501,629.80	$ 1,553,545.53
Aug-09	1,170,950	$ 3,807,952.31	$ 23.66	7.28	$ 3,944,964.64	398,942	$ 1,297,359.56	$ 1,344,035.78
Sep-09	955,927	$ 2,470,115.73	$ 18.94	7.33	$ 2,586,738.84	356,756	$ 921,857.94	$ 965,382.19
Oct-09	645,815	$ 2,330,745.61	$ 25.63	7.10	$ 2,420,513.87	327,844	$ 1,183,190.13	$ 1,228,760.49
Nov-09	395,283	$ 1,557,810.30	$ 29.89	7.58	$ 1,623,822.56	302,661	$ 1,192,786.42	$ 1,243,330.78
Dec-09	935,970	$ 4,272,703.69	$ 33.11	7.25	$ 4,388,763.99	287,794	$ 1,313,641.07	$ 1,349,323.76
Jan-10	890,560	$ 5,183,057.86	$ 41.51	7.13	$ 5,299,721.19	330,752	$ 1,924,977.40	$ 1,968,305.93
Feb-10	791,756	$ 4,259,645.13	$ 38.16	7.09	$ 4,364,156.87	312,599	$ 1,681,783.75	$ 1,723,046.84
Mar-10	224,813	$ 1,002,888.83	$ 33.31	7.47	$ 1,051,448.34	302,377	$ 1,348,902.23	$ 1,414,215.58
Apr-10	742,624	$ 2,823,456.37	$ 27.76	7.30	$ 2,935,592.59	84,561	$ 321,501.36	$ 334,270.08
May-10	750,748	$ 3,030,769.95	$ 29.64	7.34	$ 3,139,628.42	183,830	$ 742,123.18	$ 768,778.58
Jun-10	1,084,434	$ 4,477,628.48	$ 30.15	7.30	$ 4,618,604.92	400,855	$ 1,655,132.00	$ 1,707,243.20
Jul-10	1,063,612	$ 4,856,453.31	$ 37.33	8.18	$ 4,977,705.10	433,624	$ 1,979,925.29	$ 2,029,358.38
Aug-10	1,217,747	$ 5,148,533.47	$ 30.46	7.20	$ 5,299,534.07	495,894	$ 2,096,641.60	$ 2,158,132.50
Sep-10	968,276	$ 3,479,015.60	$ 26.74	7.44	$ 3,595,208.71	416,970	$ 1,498,174.88	$ 1,548,211.34
Oct-10	284,601	$ 1,041,354.33	$ 26.65	7.28	$ 1,095,713.08	374,872	$ 1,371,658.02	$ 1,443,258.64
Nov-10	702,850	$ 2,274,423.51	$ 22.80	7.05	$ 2,367,902.59	314,649	$ 1,018,205.60	$ 1,060,053.97
Dec-10	716,364	$ 2,938,527.10	$ 29.27	7.14	$ 3,030,221.75	320,868	$ 1,316,202.38	$ 1,357,273.55
Jan-11	788,032	$ 3,171,827.43	$ 29.00	7.21	$ 3,272,695.48	311,764	$ 1,254,851.06	$ 1,294,756.88
Feb-11	799,836	$ 3,528,076.60	$ 31.71	7.19	$ 3,641,653.31	300,991	$ 1,327,670.33	$ 1,370,411.02
Mar-11	304,272	$ 1,143,151.52	$ 29.28	7.79	$ 1,217,089.72	312,348	$ 1,173,493.21	$ 1,249,393.89
Apr-11	841,545	$ 3,514,709.13	$ 30.22	7.24	$ 3,608,815.00	103,956	$ 434,120.34	$ 445,867.37
May-11	930,809	$ 3,937,320.32	$ 31.36	7.42	$ 4,044,363.31	267,952	$ 1,133,436.75	$ 1,164,251.22
Jun-11	1,102,253	$ 4,757,322.74	$ 34.52	8.00	$ 4,910,535.86	317,458	$ 1,370,149.07	$ 1,414,275.75
Jul-11	1,119,881	$ 4,808,769.07	$ 30.32	7.06	$ 4,965,710.27	336,406	$ 1,444,529.08	$ 1,497,681.29
Aug-11	916,276	$ 3,848,359.69	$ 30.60	7.29	$ 3,983,968.56	446,780	$ 1,876,476.25	$ 1,942,599.70
Sep-11	910,576	$ 3,554,888.86	$ 28.28	7.24	$ 3,707,865.63	296,117	$ 1,156,039.01	$ 1,205,786.59
Oct-11	161,561	$ 583,756.80	$ 25.26	7.27	$ 623,202.01	290,800	$ 1,050,077.36	$ 1,121,032.46
Nov-11	770,091	$ 2,552,081.67	$ 23.95	7.23	$ 2,703,019.51	305,564	$ 1,012,638.53	$ 1,072,529.04
Dec-11	797,476	$ 2,604,556.47	$ 23.51	7.20	$ 2,743,317.29	106,068	$ 346,416.52	$ 364,872.27
	28,941,806				$ 117,669,414	10,632,261		$ 43,681,767
					4.07			4.11

Johnson County, Steam Output Revenue/Cost Stream

	Period Energy	Period Revenue	Revenue 36 month avg	Expense	mmBTU/mwh	Avg $/mmBTU	Expense 36 month avg
Jan 2009 - Dec 2011	1,349,799	$ 60,034,499	$ 44.48	$ 42,141,847	7.88	$ 3.96	$ 31.22

Jack County 1, Steam Output Revenue/Cost Stream

	Period Energy	Period Revenue	Revenue 36 month avg	Expense	mmBTU/mwh	Avg $/mmBTU	Expense 36 month avg
Jan 2009 - Dec 2011	3,968,191	$ 166,363,269	$ 41.92	$ 113,655,359	7.29	$ 3.93	$ 28.64

Notes:
[1] Steam Energy based on monthly EIA Reports
[2] Revenue calculations based on SCADA extracts reconciled to EIA Reports
[3] Cost stream calculations based on EIA information w/ allocation of MMBTU based on ratio of steam energy output to total plant output

Attachment D

Permit No. 25384 and PSDTX839, Special Condition 14(b),
Issued October 31, 2011

1. Top of document
2. Emission Sources - Maximum Allowable Emission Rates
3. Air Contaminants Data

Section 1 - Document

Emission Sources - Maximum Allowable Emission Rates

Permit Number 25384 and PSDTX839

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)
E-CT/HRSG	Turbine and 375 MMBtu/hr Heat Recovery Steam Generator (5)	NO_x	115.7	272.8
		NO_x (MSS)(7)	330.0	-
		CO	348.5	462.6
		CO (MSS)(7)	879.0	-
		VOC	30.0	42.3
		SO_2	87.22	72.5
		PM	57.8	65.2
		PM_{10}	57	61.9
		NH_3	32.5	130.5
		Pb	0.1	<0.1
FP-1	Fire Pump (6) 182 Hp	NO_x	1.87	0.02
		CO	0.41	<0.01
		VOC	0.15	<0.01
		SO_2	0.12	<0.01
		PM	0.13	<0.01
SO_4-TK	Sulfuric Acid Tank	VOC	<0.1	<0.1
OIL-TK1	Fuel Oil Tank	VOC	0.6	0.3
OIL-TK2	Fuel Oil Tank	VOC	0.6	0.3
MSSFUG	MSSFUG	VOC	0.26	0.05
		$PM/PM_{10}/PM_{2.5}$	0.05	<0.01

		NO_x	<0.01	<0.01
		NH_3	0.16	<0.01

(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) VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1

NO_x - total oxides of nitrogen

SO_2 - sulfur dioxide

PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$, as represented

PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$, as represented

$PM_{2.5}$ - total particulate matter equal to or less than 2.5 microns in diameter, as represented

CO - carbon monoxide

Pb - lead

NH_3 - Ammonia

(4) Compliance with annual emission limits (tons per year) is based on a 12 month rolling period.

(5) The allowable emissions shown represent worse-case emissions for 8,040 hours and 720 hours of natural gas and fuel oil firing, respectively, in the CT. The HRSG fires natural gas only and supplies steam to a 104 MW steam turbine.

(6) Source qualifies for Permit by Rule 30 TAC ' 106.511.

(7) For each pollutant whose emissions during planned MSS activities are measured using a CEMS, the MSS lb/hr limits apply only during each clock hour that includes one or more minutes of MSS activities. During all other clock hours, the normal lb/hr limits apply.

Date: October 31, 2011

Headers

Permit Number 25384 and PSDTX839

Page

Emission Sources - Maximum Allowable Emission Rates

Footers

Project Number: 162448

Project Number: 162448

Published by GroupWise

1. Top of document
    1. For each pollutant emitted during ILE planned maintenance activities, the permit holder shall annually confirm the continued validity of the estimated potential to emit represented in the permit application for all ILE planned maintenance activities. The total emissions from all ILE planned maintenance activities (See Attachment A) shall be considered to be no more than the estimated potential to emit for those activities that are represented in the permit application.
    2. All other maintenance activities may be authorized by 30 TAC § 106.263.

Section 1 - Document

Special Conditions

Permit Numbers 25384 and PSDTX839

Emission Limitations and Operating Specifications

1. This permit covers only those sources of emissions listed in the attached table entitled AEmission Sources - Maximum Allowable Emission Rates,@ and those sources are limited to the emission limits and other conditions specified in the attached table. The annual rates are based on a rolling 12-month period.

2. A copy of this permit, the June 1994 permit application, and any subsequent permit-related correspondence shall be kept at the plant site and made available at the request of personnel from the Texas Commission on Environmental Quality (TCEQ) or the local air pollution control agency. In addition, the holder of this permit shall maintain an updated site arrangement of the facility showing the location and emission point numbers (EPNs) for all sources listed on the maximum allowable emission rates table (MAERT).

3. Fuel fired in the Westinghouse Model W501F Gas Combustion Turbine (CT) and the duct burner of the heat recovery steam generator (HRSG) are limited as follows:

    A. Fuels fired in the CT:

        1. Primary fuel - pipeline-quality, sweet natural gas containing no more than 5.0 grains total sulfur and 0.25 grain of hydrogen sulfide (H_2S) per 100 dry standard cubic feet (dscf).

        2. Backup fuel - refinery-grade, first-run distillate fuel oil containing no more than 0.05 percent

sulfur by weight. Fuel oil may be fired as a backup fuel for a maximum of 720 hours per year. The permit holder must show compliance with the 720 hour limit on a rolling 12-month average.

B. Fuel fired in the HRSG duct burner is limited to pipeline-quality, sweet natural gas containing no more than 5.0 grains total sulfur and 0.25 grain of H_2S per 100 dscf.

4. The permit holder shall use steam injection to control the emissions contribution of nitrogen oxides (NO_x) from the CT prior to entering the HRSG and selective catalytic reduction (SCR) units.

5. The stack gases of the CT/HRSG Unit (EPN E-CT/HRSG) shall not exceed the emission concentrations stated below.

A. While the CT/HRSG unit is firing natural gas at base load, the concentration of NO_x and carbon monoxide (CO) in the stack gases of EPN E-CT/HRSG shall not exceed 9 parts per million by volume on a dry basis (ppmvd) and 25 ppmvd, respectively, when corrected to 15 percent oxygen (O_2). Base load is defined as operation equal to or greater than 120 MW. **(10/11)**

B. While the CT is firing fuel oil and the HRSG is firing natural gas, each at base load, the concentration of NO_x and CO in the stack gases of EPN E-CT/HRSG shall not exceed 15.5 ppmvd and 25 ppmvd, respectively, when corrected to 15 percent O_2.

6. The HRSG duct burner is limited to a maximum heat input capacity of 375 MMBtu/hr. The heat input shall be calculated on the higher heating value (HHV) of the fuel.

7. Upon request by the Director of the TCEQ Dallas/Fort Worth (DFW) Regional Office or the Executive Director of the TCEQ or any local air pollution control program having jurisdiction, the holder of this permit shall provide a sample and/or an analysis of the fuel fired in this facility or shall allow air pollution control agency representatives to obtain a sample for analysis.

8. Except during MSS activities, the opacity shall not exceed five percent averaged over a six-minute period from each stack or vent. During periods when the CT is firing fuel oil, the opacity limitation shall be 10 percent. During MSS activities, the opacity shall not exceed 15 percent (or other applicable opacity limit specified in Title 30 Texas Administrative Code (TAC) § 111.111(a)(1)(c)). Each determination shall be made by first observing for visible emissions while each facility is in operation. Observations shall be made at least 15 feet and no more than 0.25 miles from the emission point. If

visible emissions are observed from an emission point, then the opacity shall be determined and documented within 24 hours for that emission point using Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60), Appendix A, Test Method 9. Contributions from uncombined water shall not be included in determining compliance with this condition. Observations shall be performed and recorded quarterly. If the opacity exceeds five percent during normal operations, 10 percent when firing fuel oil, or 15 percent during MSS activities, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one week of first observation. **(10/11)**

Anhydrous Ammonia (NH_3)

9. The concentration of NH_3 in the exhaust gases of the EPN E-CT/HRSG shall not exceed 10 parts per million by volume (ppmv) when corrected to 15 percent O_2.

10. The permit holder shall maintain a quantity of no more than 12,000 gallons of NH_3 on-site at any time. Additionally, the permit holder shall maintain prevention and protection measures for the NH_3 storage system as represented in Table 4-1 of the supplemental letter dated August 22, 1994, submitted during the review of the June 1994 application for this permit. The letter includes the following:

    A. Relief valves shall be discharged to the HRSG Stack (EPN E-CT/HRSG) rather than releasing directly to the atmosphere at ground level.

    B. The tank area will be diked so as to contain at least the volume of the pressure vessel.

    C. A water deluge system shall be installed to cover the tank and diked area to mitigate any airborne releases of NH_3. The water deluge system must activate when a level of 200 ppmv of NH_3 is detected.

    D. Any NH_3 solution contained by the dike area shall be immediately transported to a safe disposal area.

11. In the event of a release of the NH_3 from the liquid fill line, pressure vessel due to overpressurization, process line to the SCR system, or the vapor return lines from the vaporizer or any other accidental release of NH_3, the permit holder shall follow the contingency plan and mitigation procedures set out in Sections 5.0 and 6.0 of the August 22, 1994 letter regarding the use of NH_3.

12. In addition to the requirements of Special Condition Nos. 10 and 11, the permit holder shall maintain the piping and valves in NH_3 service as follows:

    A. All operating practices and procedures relating to the handling and storage of NH_3 shall conform to the safety recommendations specified for that compound by guidelines of the American National Standards Institute and the Compressed Gas Association.

    B. Audio, olfactory, and visual checks for NH_3 leaks within the operating area shall be made every four hours.

    C. Immediately, but no later than one hour upon the detection of a leak, plant personnel shall take the following actions:

        1. Locate and isolate the leak, if necessary.

        2. Commence repair or replacement of the leaking component.

        3. Use a leak collection/containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

13. All necessary plant employees shall undergo proper training in the maintenance, mitigation, and contingency procedures necessary to prevent, control, or handle accidental releases of NH_3.

Federal Applicability

14. These facilities shall comply with applicable requirements of the EPA regulations on Standards of Performance for New Stationary Sources, Title 40 Code of Federal Regulations (40 CFR) Part 60, promulgated for:

    A. General Conditions, Subpart A.

B. The heat recovery steam generators are subject to the requirements of Subpart Da, Standards of Performance for Electric Utility Steam Generating Units.

C. The Westinghouse Model W501F Gas Turbine is subject to the requirements of Subpart GG, Standards of Performance for Stationary Gas Turbines.

If any condition of this permit is more stringent than the regulations so incorporated, then for the purposes of complying with this permit, the permit shall govern and be the standard by which compliance shall be demonstrated.

Initial Determination of Compliance

15. Sampling ports and platforms shall be incorporated into the design of the HRSG exhaust stacks according to the specifications set forth in the attachment entitled AChapter 2, Stack Sampling Facilities.@ Alternate sampling facility designs may be submitted for approval by the TCEQ DFW Regional Director or the TCEQ Air Permits Division.

16. The holder of this permit shall perform stack sampling and other testing as required to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from EPN E-CT/HRSG. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and in accordance with the appropriate EPA Reference Methods for NO_x, CO, volatile organic compounds (VOC), sulfur dioxide (SO_2), NH_3, particulate matter less than 10 microns in diameter (PM_{10}), and opacity.

Fuel sampling using the methods and procedures of 40 CFR ' 60.335(d) may be conducted in lieu of stack sampling for SO_2. If fuel sampling is used, compliance with New Source Performance Standards (NSPS) Subpart GG, SO_2 limits shall be based on 100 percent conversion of the sulfur in the fuel to SO_2. Any deviations from those procedures must be approved by the TCEQ Air Permits Division or the TCEQ DFW Regional Director prior to sampling. The TCEQ Executive Director or his designated representative shall be afforded the opportunity to observe all such sampling.

The holder of this permit is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense.

A. The TCEQ DFW Regional Office shall be contacted as soon as testing is scheduled but not less than 45 days prior to sampling to schedule a pretest meeting.

The notice shall include:

1. Date for pretest meeting.

2. Date sampling will occur.

3. Name of firm conducting sampling.

4. Type of sampling equipment to be used.

5. Method or procedure to be used in sampling.

6. Procedure used to determine turbine loads during and after the sampling period.

7. A plan to develop computer-generated calculations of NO_x and CO emissions in pounds per hour and tons per rolling 12-month period. The plan shall include the equations used to convert the monitored concentrations to mass emission rates. The computer calculated hourly values are to be generated and compared to the initial stack sampling results to demonstrate the relative accuracy of the computer-generated output.

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. A written proposed description of any deviation from sampling procedures specified in permit conditions, TCEQ, or EPA sampling procedures shall be made available to the TCEQ prior to the pretest meeting. The TCEQ DFW Regional Director or the TCEQ Air Permits Division shall approve or disapprove of any deviation from specified sampling procedures. Requests to waive testing for any pollutant specified in this condition shall be submitted to the TCEQ Office Air, Air Permits Division. Test waivers and alternate/equivalent procedure proposals for NSPS testing which must have EPA approval shall be submitted to the TCEQ Air Permits Division in Austin.

B. Air contaminants emitted from the CT/HRSG unit to be tested for include (but are not limited to) NO_x, CO, SO_2, VOC, PM_{10}, NH_3, O_2, and opacity. The CT shall be tested at a minimum of four points in the normal operating range including full load for the atmospheric conditions which exist during testing while firing natural gas and fuel oil. The HRSG duct burners shall be tested at the maximum firing rate of 450 MMBtu/hr (HHV) while firing natural gas.

C. Sampling shall occur within 60 days after achieving the maximum production rate at which the facility will be operated but no later than 180 days after initial start-up. The TCEQ and EPA may require additional sampling at other times as they deem appropriate.

D. Within 60 days after the completion of the testing and sampling required herein, copies of the sampling report shall be distributed as follows.

One copy to the TCEQ DFW Regional Office.

One copy to the TCEQ Office of Air.

One copy to the EPA Region 6 in Dallas.

Continuous Determination of Compliance

17. The holder of this permit shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) to:

A. Measure and record the concentrations of NO_x, CO, NH_3, and O_2 at the CT/HRSG exhaust stack. The NO_x and CO concentrations shall be corrected and reported in accordance with Special Condition No. 5. The NH_3 concentrations shall be corrected and reported in accordance with Special Condition No. 9.

B. The CEMS required in Special Condition No. 17A shall comply with the following requirements:

1. The CEMS shall 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 60, Appendix B. The Performance Specification tests shall be conducted during the sampling required by Special Condition No. 16, and written copies of the results shall be submitted within 60 days of completion of the tests to the TCEQ DFW Regional Office and the Air Enforcement Branch of EPA in Dallas.

2. The system shall be zeroed and spanned daily and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in 40 CFR Part 60, Appendix B. Each gaseous monitor shall be quality-assured at least quarterly using cylinder gas audits (CGA). The CGA method to be used is contained in 40 CFR Part 60, Appendix F, Procedure 1, ' 5.1.2. An equivalent method approved by the EPA and TCEQ may be used.

3. The gaseous monitoring data shall be reduced to hourly average concentrations at least once everyday, using a minimum of four equally-spaced data points from each one-hour period.

Two valid data points shall be generated during the hourly period in which zero and span is performed.

4. The CEMS shall demonstrate 90 percent monitor data availability on a monthly basis. The percent monitor data availability shall be calculated as the total unit operating hours for which quality-assured data was recorded divided by the total unit operating hours.

5. All CGA exceedances greater than "15 percent accuracy and any unscheduled CEMS downtime shall be reported to the TCEQ Fort Worth Regional Office and the Air Enforcement Branch of EPA in Dallas, and necessary corrective action shall be taken. Unscheduled CEMS downtime is any CEMS downtime not required for daily zero and span checks, quarterly CGAs, and annual relative accuracy test audits. Supplemental stack concentration measurements may be required at the discretion of the TCEQ DFW Regional Director or the EPA.

6. The CEMS shall demonstrate an annual system reliability of at least 90 percent (downtime does not include daily zero and span measurement time or cogeneration unit downtime) or options to increase system reliability to an acceptable value, including a redundant CEMS, may be required by the TCEQ DFW Regional Director.

7. For NSPS sources subject to Appendix F, the TCEQ DFW Regional Office and EPA NSRS in Dallas shall be notified at least 30 days prior to each annual relative accuracy testing audit in order to provide them the opportunity to observe the testing.

18. The holder of this permit shall additionally install, calibrate, maintain, and operate continuous monitoring systems to monitor and record the average hourly fuel and water consumption in the gas turbines. The systems shall be accurate to "5.0 percent, and the system shall be approved by the Air Permits Division of the TCEQ prior to conducting the initial compliance demonstration required by Special Condition No. 16.

19. If the NH_3 CEMS is not able to show continuous demonstration of compliance, then the facility shall implement wet chemical sampling or an alternative TCEQ-approved method of estimating NH_3 emissions. The holder of this permit shall monitor NH_3 concentration (ppmv) and stack gas flow rate in standard cubic feet per minute in the SCR unit exhaust stack. The measured NH_3 concentration and flow rate shall be used to calculate the NH_3 emission rate in pounds per hour and cumulative tons per year to determine compliance with Special Condition Nos. 1 and 9.

20. The holder of this permit shall develop a program to calculate the total mass flow rate through each

cogeneration train by using a mass balance of fuel, steam, and ammonia into the CT/HRSG unit and exhaust flow out of the HRSG stack to ensure continuous compliance with Special Condition No. 5.

A. Using the calculated flow rate and the concentrations of NO_x, NH_3, and CO from the CEMS required in Special Condition No. 17, the exhaust emissions from EPN E-CT/HRSG for NO_x, NH_3, and CO in units of pounds/hour shall be calculated on an hourly basis.

B. The hourly calculated values will be cumulatively added during each hour of the month and stored in the computer hard drive and on individually stored disks or other TCEQ-accepted computer media. Records of this information will also be available in a form suitable for inspection.

C. During periods in which the CEMS is unable to produce a valid average concentration, hourly emissions will be calculated from monitoring of operational parameters including the CT and HRSG firing rates, air temperature, steam injection rate, NH_3 injection rate, estimated NH_3 slip, and fuel flow rate.

21. In order to ensure that the CT/HRSG Unit (EPN E-CT/HRSG) and associated air pollution control equipment is operating at optimal conditions, the holder of this permit shall perform and maintain records of the following:

A. During base load operations, when the average NO_x stack outlet concentration increases above 9 ppmv or 15.5 ppmv while firing natural gas or fuel oil, respectively, for more than one hour, the holder of this permit shall investigate and determine the reason for the increase in NO_x concentrations and, if needed, repair the SCR unit and/or its associated equipment as soon as possible. The NO_x concentration shall be corrected to 15 percent O_2. The holder of this permit will take appropriate steps, as necessary, to ensure the SCR unit is operating in compliance with Special Condition Nos. 1 and 5 until repairs can be made.

If the NO_x concentration is greater than those required by Special Condition No. 5 for more than 24 hours, the holder shall notify the TCEQ DFW Regional Office either verbally or with a written report detailing the cause of the increase in emissions and all efforts being made to correct the problem. If the NO_x concentration does not decrease to meet the requirements of Special Condition No. 5 within two weeks of the initial date of increase in NO_x concentrations, the holder shall commence with shutdown procedures.

B. When the average CO stack outlet concentration from increases above 25 ppmv at full load or 240 ppmv at part load or 60 ppmv during power augmentation while firing natural gas or fuel oil, respectively, for more than one hour, the holder of this permit shall investigate and determine the

reason for the increase in CO concentrations and, if needed, repair the HRSG and/or its associated equipment as soon as possible. All concentrations shall be corrected to 15 percent O_2. The holder of this permit will take appropriate steps, as necessary, to ensure the HRSG is operating in compliance with Special Condition Nos. 1 and 5 until repairs can be made.

If the concentration is greater than those required by Special Condition No. 5 for more than 24 hours, the holder shall notify the TCEQ DFW Regional Office either verbally or with a written report, detailing the cause of the increase in emissions and all efforts being made to correct the problem. If the CO concentration does not decrease to meet the requirements of Special Condition No. 5 within two weeks of the initial date of increase in CO concentrations, the holder shall commence with shutdown procedures.

C. When the average NH_3 outlet concentration from the SCR increases above 10 ppmv for more than one hour, the holder of this permit shall investigate and determine the reason for the increase in NH_3 concentrations and, if needed, repair the SCR and/or its associated equipment as soon as possible. The NH_3 concentration shall be corrected to 15 percent O_2. The holder of this permit will take appropriate steps, as necessary, to ensure the SCR unit is operating in compliance with Special Condition Nos. 1 and 9 until repairs can be made.

If the NH_3 concentration is not in compliance with Special Condition No. 9 for more than 24 hours, the holder shall notify the TCEQ DFW Regional Office either verbally or with a written report, detailing the cause of the increase in emissions and all efforts being made to correct the problem. If the NH_3 concentration does not decrease to meet the requirements of Special Condition No. 9 within two weeks of the initial date of increase in NH_3 concentrations, the holder shall commence with shutdown procedures.

22. The holder of this permit shall monitor the fuels fired in the equipment authorized by this permit for fuel-bound sulfur as specified in 40 CFR ' 60.334(b). Any request for a custom monitoring schedule shall be made in writing and directed to the Air Permits Division of the TCEQ although authority for granting such custom schedules remains with the EPA. Any custom schedule approved by EPA pursuant to 40 CFR ' 60.334(b) will be recognized as enforceable conditions of this permit provided that the holder of this permit demonstrates that the conditions of such custom schedule will be adequate to demonstrate continuous compliance with Special Condition Nos. 1 and 3.

Compliance and Maintenance

23. On an annual basis or during routine unit turnarounds, the low-NO_x duct burners of the HRSG shall be visually inspected for erosion, corrosion, plugging, or any other alternation that may adversely affect low-NO_x performance. The TCEQ DFW Regional Office shall be notified at least seven days prior to the inspection in order to be given an opportunity to witness the inspection procedure.

24. A written description of any deviation from the monitoring required herein shall be made available to the

TCEQ prior to the pretest meeting required in Special Condition No. 16. The TCEQ DFW Regional Director or the TCEQ Air Permits Division in Austin, and the EPA in Dallas shall approve or disapprove of any request for an alternate monitoring requirement. Such approval shall be obtained prior to the date required to conduct stack sampling under Special Condition No. 16.

Planned Maintenance Startup and Shutdown (MSS)

25. This permit authorizes the emissions from the planned maintenance, startup, and shutdown (MSS) activities listed in Attachment A, or the MAERT attached to this permit. Attachment A identifies the inherently low emitting (ILE) planned maintenance activities that this permit authorizes to be performed. **(10/11)**

26. The emissions limits that are identified in Special Conditions 5A, 5B and 9 shall not apply during planned MSS activities. **(10/11)**

27. The holder of this permit shall minimize emissions during planned maintenance, start-up and shutdown (MSS) activities by operating the facility and associated air pollution control equipment in accordance with good air pollution control practices, safe operating practices, and protection of the facility. **(10/11)**

28. Emissions during planned startup and shutdown activities will be minimized by limiting the duration of operation in planned startup and shutdown mode as follows: **(10/11)**

    A. A planned startup of the electric generating facility (EGF) with EPN No. E-CT/HRSG is defined as the period that begins when fuel is first fed to the unit and ends when the load on the unit reaches 120 MW. A planned startup for that EGF shall not exceed four hours.

    B. A planned shutdown of the EGF with EPN No. E-CT/HRSG is defined as the period that begins when the load on the unit drops below 120 MW and ends when fuel is no longer fed to the unit. A planned shutdown for that EGF shall not exceed two hours.

29. Compliance with the emissions limits for planned MSS activities identified in the MAERT attached to this permit may be demonstrated as follows. **(10/11)**

    A. For each pollutant emitted during ILE planned maintenance activities, the permit holder shall annually confirm the continued validity of the estimated potential to emit represented in the permit application for all ILE planned maintenance activities. The total emissions from all ILE planned

maintenance activities (See Attachment A) shall be considered to be no more than the estimated potential to emit for those activities that are represented in the permit application.

B. All other maintenance activities may be authorized by 30 TAC § 106.263.

30. With the exception of the emission limits in the MAERT attached to this permit, the permit conditions relating to planned MSS activities do not become effective until 180 days after issuance of the permit amendment that added such conditions. **(10/11)**

Recordkeeping Requirements

31. The following information shall be made and maintained by the holder of this permit in a form suitable for inspection for a period of two years and shall be made immediately available upon request to representatives of the TCEQ, EPA, or any local air pollution control program having jurisdiction:

A. Written records of any accidental releases, spills, or venting of NH_3 and the corrective action taken in accordance with Special Condition Nos. 10 and 11.

B. Written records of maintenance performed to any piping and valves in NH_3 service pursuant to Special Condition No. 12.

C. A complete copy of the testing report and records of the initial performance testing completed pursuant to Special Condition No. 16.

D. Records of the CEMS data required by Special Condition No. 17 to demonstrate continuous compliance with Special Condition No. 5.

E. Records of average hourly fuel and water consumption in the gas turbines pursuant to Special Condition No. 18.

F. Records of any NH_3 emissions calculations or testing performed during CEMS downtime pursuant to Special Condition No. 19

G. Calculations of predicted hourly NO_x, CO, and NH_3 emissions from the HRSG exhaust stacks when required by Special Condition No. 20.

H. Written records of any modifications or maintenance performed upon the equipment authorized by this permit.

I. Raw data files of all CEMS data including calibration checks and adjustments and maintenance performed on these systems of devices in a permanent form suitable for inspection.

J. Records of any maintenance or corrective action taken to maintain SCR performance pursuant to Special Condition No. 21.

K. Records of fuel sampling conducted pursuant to Special Condition No. 22 to demonstrate continuous compliance with Special Condition Nos. 1 and 3.

L. Written records of inspections conducted pursuant to Special Condition No. 23.

M. Field records of quarterly opacity observation as prescribed in 40 CFR 60, Appendix A, Test Method 9. **(10/11)**

N. A log of all startups and shutdowns and durations to demonstrate compliance with Special Condition No. 28. **(10/11)**

Reporting

32. The holder of this permit shall submit to the TCEQ DFW 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. In addition to the information specified in 40 CFR ' 60.7(c), each report shall contain the hours of operation of the facility and a report summary of the periods of noncomplying emissions and CEMS downtimes by cause. Additionally, the report shall contain the duration, cause, and corrective action taken for any accidental release of NH_3.

33. For the purposes of reporting pursuant to Special Condition No. 26, noncomplying emissions from EPN E-CT/HRSG may be defined as follows:

A. Noncomplying emissions of NO_x or CO may be defined as each one-hour period of operation, except during planned MSS (defined as turbine operation at less than 120 MW, not to exceed four hours) during which the average emissions of NO_x or CO, as measured and recorded by the CEMS, exceed the emission limitations of Special Condition No. 5.

B. Noncomplying annual emissions of NO_x may be defined as a rolling 12-month period during which the 12-month cumulative emissions of NO_x exceed the annual limits specified in the table referenced in Special Condition No. 1.

C. Noncomplying emissions of NH_3 may be defined as each one-hour period of operation, except during planned MSS (defined as turbine operation at less than 120 MW, not to exceed four hours) during which the average emissions of NH_3 as measured and recorded by the CEMS, exceed the emission limitations of Special Condition No. 9.

D. For any period of operation except planned MSS during which the CEMS is unable to provide valid hourly emissions, noncomplying emissions of NO_x may be defined as each hourly period for which the predicted emissions of NO_x calculated in Special Condition No. 20 exceeds Special Condition No. 5.

E. For any period of operation except planned MSS during which the CEMS is unable to provide valid hourly emissions, noncomplying emissions of CO may be defined as each hourly period for which the predicted emissions of NO_x calculated in Special Condition No. 20 exceeds Special Condition No. 5.

F. For any period of operation except planned MSS during which the CEMS is unable to provide valid hourly emissions, noncomplying emissions of NH_3 may be defined as:

1. Each hourly period for which the predicted emissions of NH_3 calculated in Special Condition No. 20 that exceeds Special Condition No 1.

2. Any sample of which is found to contain NH_3 in excess of the limits of Special Condition No. 9 or which indicates exceedance of the NH_3 limitation required in Special Condition No. 1.

G. Noncomplying emissions of SO_2 may be defined as fuel which is found to contain sulfur in excess of the limits of Special Condition No. 3 or which indicates exceedance of the SO_2 limitation required in Special Condition No. 1, based on 100 percent conversion of the sulfur in the fuel to SO_2.

Dated October 31, 2011

Attachment A

Permit No. 25384 and PSDTX839

Inherently Low Emitting (ILE) Planned Maintenance Activities

	Emissions				
Planned Maintenance Activity	NH_3	VOC	NO_x	CO	PM SO_2
Gaseous Venting and Line Purging	x	x			
Miscellaneous particulate filter maintenance[1]					x
CEMS Calibration	x		x	x	
Small Equipment Maintenance – Low Vapor Pressure VOC		x			
Sludge Management[2]		x			

Notes:

1. Includes, but is not limited to filters, process-related building air filters, and combustion turbine air intake filters.
2. Includes, but is not limited to, management by vacuum truck/dewatering of materials in sumps, tanks and other closed or open vessels. Materials managed include water and sludge mixtures containing miscellaneous VOCs such as diesel, lube oil, and other waste oils.

Headers

Special Conditions

Permit Numbers 25384 and PSDTX839

Page

Attachment E

Permit No. 25384 and PSDTX839, Special Condition 14(b),
Issued February 13, 2012

1. Top of document
    1. For each pollutant emitted during ILE planned maintenance activities, the permit holder shall annually confirm the continued validity of the estimated potential to emit represented in the permit application for all ILE planned maintenance activities. The total emissions from all ILE planned maintenance activities (See Attachment A) shall be considered to be no more than the estimated potential to emit for those activities that are represented in the permit application.
    2. All other maintenance activities may be authorized by 30 TAC § 106.263.

Section 1 - Document

Special Conditions

Permit Numbers 25384 and PSDTX839

Emission Limitations and Operating Specifications

1. This permit covers only those sources of emissions listed in the attached table entitled AEmission Sources - Maximum Allowable Emission Rates,@ and those sources are limited to the emission limits and other conditions specified in the attached table. The annual rates are based on a rolling 12-month period.

2. A copy of this permit, the June 1994 permit application, and any subsequent permit-related correspondence shall be kept at the plant site and made available at the request of personnel from the Texas Commission on Environmental Quality (TCEQ) or the local air pollution control agency. In addition, the holder of this permit shall maintain an updated site arrangement of the facility showing the location and emission point numbers (EPNs) for all sources listed on the maximum allowable emission rates table (MAERT).

3. Fuel fired in the Westinghouse Model W501F Gas Combustion Turbine (CT) and the duct burner of the heat recovery steam generator (HRSG) are limited as follows:

    A. Fuels fired in the CT:

        1. Primary fuel - pipeline-quality, sweet natural gas containing no more than 5.0 grains total sulfur and 0.25 grain of hydrogen sulfide (H_2S) per 100 dry standard cubic feet (dscf).

        2. Backup fuel - refinery-grade, first-run distillate fuel oil containing no more than 0.05 percent

sulfur by weight. Fuel oil may be fired as a backup fuel for a maximum of 720 hours per year. The permit holder must show compliance with the 720 hour limit on a rolling 12-month average.

B. Fuel fired in the HRSG duct burner is limited to pipeline-quality, sweet natural gas containing no more than 5.0 grains total sulfur and 0.25 grain of H_2S per 100 dscf.

4. The permit holder shall use steam injection to control the emissions contribution of nitrogen oxides (NO_x) from the CT prior to entering the HRSG and selective catalytic reduction (SCR) units.

5. The stack gases of the CT/HRSG Unit (EPN E-CT/HRSG) shall not exceed the emission concentrations stated below.

A. While the CT/HRSG unit is firing natural gas at base load, the concentration of NO_x and carbon monoxide (CO) in the stack gases of EPN E-CT/HRSG shall not exceed 9 parts per million by volume on a dry basis (ppmvd) and 25 ppmvd, respectively, when corrected to 15 percent oxygen (O_2). Base load operation shall be defined as operation equal to or greater than 162 megawatts (MW). **(2/12)**

B. While the CT is firing fuel oil and the HRSG is firing natural gas, each at base load, the concentration of NO_x and CO in the stack gases of EPN E-CT/HRSG shall not exceed 15.5 ppmvd and 25 ppmvd, respectively, when corrected to 15 percent O_2.

C. Reduced load operation (defined as operation at less than 162 MW) not associated with

startup or shutdown is authorized provided the maximum pounds per hour (lb/hr)

emissions rates specified in the MAERT are not exceeded. **(2/12)**

6. The HRSG duct burner is limited to a maximum heat input capacity of 375 million British thermal units per hour (MMBtu/hr). The heat input shall be calculated on the higher heating value (HHV) of the fuel.

7. Upon request by the Director of the TCEQ Dallas/Fort Worth (DFW) Regional Office or the Executive Director of the TCEQ or any local air pollution control program having jurisdiction, the holder of this permit shall provide a sample and/or an analysis of the fuel fired in this facility or shall allow air pollution control agency representatives to obtain a sample for analysis.

8. Except during maintenance, startup and shutdown (MSS) activities, the opacity shall not exceed five percent averaged over a six-minute period from each stack or vent. During periods when the CT is firing fuel oil, the opacity limitation shall be 10 percent. During MSS activities, the opacity shall not exceed 15 percent (or other applicable opacity limit specified in Title 30 Texas Administrative Code (TAC) § 111.111(a)(1)). Each determination shall be made by first observing for visible emissions while each facility is in operation. Observations shall be made at least 15 feet and no more than 0.25 miles from the emission point. If visible emissions are observed from an emission point, then the opacity shall be determined and documented within 24 hours for that emission point using Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60), Appendix A, Test Method 9. Contributions from uncombined water shall not be included in determining compliance with this condition. Observations shall be performed and recorded quarterly. If the opacity exceeds five percent during normal operations, 10 percent when firing fuel oil, or 15 percent during MSS activities, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one week of first observation. **(10/11)**

Anhydrous Ammonia (NH_3)

9. The concentration of NH_3 in the exhaust gases of the EPN E-CT/HRSG shall not exceed 10 parts per million by volume (ppmv) when corrected to 15 percent O_2.

10. The permit holder shall maintain a quantity of no more than 12,000 gallons of NH_3 on-site at any time. Additionally, the permit holder shall maintain prevention and protection measures for the NH_3 storage system as represented in Table 4-1 of the supplemental letter dated August 22, 1994, submitted during the review of the June 1994 application for this permit. The letter includes the following:

    A. Relief valves shall be discharged to the HRSG Stack (EPN E-CT/HRSG) rather than releasing directly to the atmosphere at ground level.

    B. The tank area will be diked so as to contain at least the volume of the pressure vessel.

    C. A water deluge system shall be installed to cover the tank and diked area to mitigate any airborne releases of NH_3. The water deluge system must activate when a level of 200 ppmv of NH_3 is detected.

    D. Any NH_3 solution contained by the dike area shall be immediately transported to a safe disposal area.

11. In the event of a release of the NH_3 from the liquid fill line, pressure vessel due to overpressurization, process line to the SCR system, or the vapor return lines from the vaporizer or any other accidental release of NH_3, the permit holder shall follow the contingency plan and mitigation procedures set out in Sections 5.0 and 6.0 of the August 22, 1994 letter regarding the use of NH_3.

12. In addition to the requirements of Special Condition Nos. 10 and 11, the permit holder shall maintain the piping and valves in NH_3 service as follows:

    A. All operating practices and procedures relating to the handling and storage of NH_3 shall conform to the safety recommendations specified for that compound by guidelines of the American National Standards Institute and the Compressed Gas Association.

    B. Audio, olfactory, and visual checks for NH_3 leaks within the operating area shall be made every four hours.

    C. Immediately, but no later than one hour upon the detection of a leak, plant personnel shall take the following actions:

        1. Locate and isolate the leak, if necessary.

        2. Commence repair or replacement of the leaking component.

        3. Use a leak collection/containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

13. All necessary plant employees shall undergo proper training in the maintenance, mitigation, and contingency procedures necessary to prevent, control, or handle accidental releases of NH_3.

Federal Applicability

14. These facilities shall comply with applicable requirements of the EPA regulations on Standards of Performance for New Stationary Sources, 40 CFR Part 60, promulgated for:

    A. General Conditions, Subpart A.

    B. The heat recovery steam generator is subject to the requirements of Subpart Da, Standards of Performance for Electric Utility Steam Generating Units.

    C. The Westinghouse Model W501F Gas Turbine is subject to the requirements of Subpart GG, Standards of Performance for Stationary Gas Turbines.

    If any condition of this permit is more stringent than the regulations so incorporated, then for the purposes of complying with this permit, the permit shall govern and be the standard by which compliance shall be demonstrated.

Initial Determination of Compliance

15. Sampling ports and platforms shall be incorporated into the design of the HRSG exhaust stacks according to the specifications set forth in the attachment entitled AChapter 2, Stack Sampling Facilities.@ Alternate sampling facility designs may be submitted for approval by the TCEQ DFW Regional Director or the TCEQ Air Permits Division.

16. The holder of this permit shall perform stack sampling and other testing as required to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from EPN E-CT/HRSG. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and in accordance with the appropriate EPA Reference Methods for NO_x, CO, volatile organic compounds (VOC), sulfur dioxide (SO_2), NH_3, particulate matter less than 10 microns in diameter (PM_{10}), and opacity.

    Fuel sampling using the methods and procedures of 40 CFR ' 60.335(d) may be conducted in lieu of stack sampling for SO_2. If fuel sampling is used, compliance with New Source Performance Standards (NSPS) Subpart GG, SO_2 limits shall be based on 100 percent conversion of the sulfur in the fuel to SO_2. Any deviations from those procedures must be approved by the TCEQ Air Permits Division or the TCEQ DFW Regional Director prior to sampling. The TCEQ Executive Director or his designated representative shall be afforded the opportunity to observe all such sampling.

    The holder of this permit is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense.

A. The TCEQ DFW Regional Office shall be contacted as soon as testing is scheduled but not less than 45 days prior to sampling to schedule a pretest meeting.

The notice shall include:

1. Date for pretest meeting.

2. Date sampling will occur.

3. Name of firm conducting sampling.

4. Type of sampling equipment to be used.

5. Method or procedure to be used in sampling.

6. Procedure used to determine turbine loads during and after the sampling period.

7. A plan to develop computer-generated calculations of NO_x and CO emissions in pounds per hour and tons per rolling 12-month period. The plan shall include the equations used to convert the monitored concentrations to mass emission rates. The computer calculated hourly values are to be generated and compared to the initial stack sampling results to demonstrate the relative accuracy of the computer-generated output.

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. A written proposed description of any deviation from sampling procedures specified in permit conditions, TCEQ, or EPA sampling procedures shall be made available to the TCEQ prior to the pretest meeting. The TCEQ DFW Regional Director or the TCEQ Air Permits Division shall approve or disapprove of any deviation from specified sampling procedures. Requests to waive testing for any pollutant specified in this condition shall be submitted to the TCEQ Office Air, Air Permits Division. Test waivers and alternate/equivalent procedure proposals for NSPS testing which must have EPA approval shall be submitted to the TCEQ Air Permits Division in Austin.

B. Air contaminants emitted from the CT/HRSG unit to be tested for include (but are not limited to) NO_x, CO, SO_2, VOC, PM_{10}, NH_3, O_2, and opacity. The CT shall be tested at a minimum of four points in the normal operating range including full load for the atmospheric conditions which exist during testing while firing natural gas and fuel oil. The HRSG duct burners shall be tested at the

maximum firing rate of 450 MMBtu/hr (HHV) while firing natural gas.

C. Sampling shall occur within 60 days after achieving the maximum production rate at which the facility will be operated but no later than 180 days after initial start-up. The TCEQ and EPA may require additional sampling at other times as they deem appropriate.

D. Within 60 days after the completion of the testing and sampling required herein, copies of the sampling report shall be distributed as follows.

One copy to the TCEQ DFW Regional Office.

One copy to the TCEQ Office of Air.

One copy to the EPA Region 6 in Dallas.

Continuous Determination of Compliance

17. The holder of this permit shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) to:

A. Measure and record the concentrations of NO_x, CO, NH_3, and O_2 at the CT/HRSG exhaust stack. The NO_x and CO concentrations shall be corrected and reported in accordance with Special Condition No. 5. The NH_3 concentrations shall be corrected and reported in accordance with Special Condition No. 9.

B. The CEMS required in Special Condition No. 17A shall comply with the following requirements:

1. The CEMS shall 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 60, Appendix B. The Performance Specification tests shall be conducted during the sampling required by Special Condition No. 16, and written copies of the results shall be submitted within 60 days of completion of the tests to the TCEQ DFW Regional Office and the Air Enforcement Branch of EPA in Dallas.

2. The system shall be zeroed and spanned daily and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in 40 CFR Part 60, Appendix B. Each

gaseous monitor shall be quality-assured at least quarterly using cylinder gas audits (CGA). The CGA method to be used is contained in 40 CFR Part 60, Appendix F, Procedure 1, ' 5.1.2. An equivalent method approved by the EPA and TCEQ may be used.

3. The gaseous monitoring data shall be reduced to hourly average concentrations at least once every day, using a minimum of four equally-spaced data points from each one-hour period. Two valid data points shall be generated during the hourly period in which zero and span is performed.

4. The CEMS shall demonstrate 90 percent monitor data availability on a monthly basis. The percent monitor data availability shall be calculated as the total unit operating hours for which quality-assured data was recorded divided by the total unit operating hours.

5. All CGA exceedances greater than "15 percent accuracy and any unscheduled CEMS downtime shall be reported to the TCEQ DFW Regional Office and the Air Enforcement Branch of EPA in Dallas, and necessary corrective action shall be taken. Unscheduled CEMS downtime is any CEMS downtime not required for daily zero and span checks, quarterly CGAs, and annual relative accuracy test audits. Supplemental stack concentration measurements may be required at the discretion of the TCEQ DFW Regional Director or the EPA.

6. The CEMS shall demonstrate an annual system reliability of at least 90 percent (downtime does not include daily zero and span measurement time or cogeneration unit downtime) or options to increase system reliability to an acceptable value, including a redundant CEMS, may be required by the TCEQ DFW Regional Director.

7. For NSPS sources subject to Appendix F, the TCEQ DFW Regional Office and EPA NSRS in Dallas shall be notified at least 30 days prior to each annual relative accuracy testing audit in order to provide them the opportunity to observe the testing.

18. The holder of this permit shall additionally install, calibrate, maintain, and operate continuous monitoring systems to monitor and record the average hourly fuel and water consumption in the gas turbines. The systems shall be accurate to "5.0 percent, and the system shall be approved by the Air Permits Division of the TCEQ prior to conducting the initial compliance demonstration required by Special Condition No. 16.

19. If the NH_3 CEMS is not able to show continuous demonstration of compliance, then the facility shall implement wet chemical sampling or an alternative TCEQ-approved method of estimating NH_3 emissions. The holder of this permit shall monitor NH_3 concentration (ppmv) and stack gas flow rate in

standard cubic feet per minute in the SCR unit exhaust stack. The measured NH_3 concentration and flow rate shall be used to calculate the NH_3 emission rate in pounds per hour and cumulative tons per year to determine compliance with Special Condition Nos. 1 and 9.

20. The holder of this permit shall develop a program to calculate the total mass flow rate through each cogeneration train by using a mass balance of fuel, steam, and ammonia into the CT/HRSG unit and exhaust flow out of the HRSG stack to ensure continuous compliance with Special Condition No. 5.

    A. Using the calculated flow rate and the concentrations of NO_x, NH_3, and CO from the CEMS required in Special Condition No. 17, the exhaust emissions from EPN E-CT/HRSG for NO_x, NH_3, and CO in units of pounds/hour shall be calculated on an hourly basis.

    B. The hourly calculated values will be cumulatively added during each hour of the month and stored in the computer hard drive and on individually stored disks or other TCEQ-accepted computer media. Records of this information will also be available in a form suitable for inspection.

    C. During periods in which the CEMS is unable to produce a valid average concentration, hourly emissions will be calculated from monitoring of operational parameters including the CT and HRSG firing rates, air temperature, steam injection rate, NH_3 injection rate, estimated NH_3 slip, and fuel flow rate.

21. In order to ensure that the CT/HRSG Unit (EPN E-CT/HRSG) and associated air pollution control equipment is operating at optimal conditions, the holder of this permit shall perform and maintain records of the following:

    A. During base load operations, when the average NO_x stack outlet concentration increases above 9 ppmv or 15.5 ppmv while firing natural gas or fuel oil, respectively, for more than one hour, the holder of this permit shall investigate and determine the reason for the increase in NO_x concentrations and, if needed, repair the SCR unit and/or its associated equipment as soon as possible. The NO_x concentration shall be corrected to 15 percent O_2. The holder of this permit will take appropriate steps, as necessary, to ensure the SCR unit is operating in compliance with Special Condition Nos. 1 and 5 until repairs can be made.

    If the NO_x concentration is greater than those required by Special Condition No. 5 for more than 24 hours, the holder shall notify the TCEQ DFW Regional Office either verbally or with a written report detailing the cause of the increase in emissions and all efforts being made to correct the problem. If the

NO_x concentration does not decrease to meet the requirements of Special Condition No. 5 within two weeks of the initial date of increase in NO_x concentrations, the holder shall commence with shutdown procedures.

B. When the average CO stack outlet concentration increases above 25 ppmv at base load or 240 ppmv at reduced load or 60 ppmv during power augmentation while firing natural gas or fuel oil, respectively, for more than one hour, the holder of this permit shall investigate and determine the reason for the increase in CO concentrations and, if needed, repair the HRSG and/or its associated equipment as soon as possible. All concentrations shall be corrected to 15 percent O_2. The holder of this permit will take appropriate steps, as necessary, to ensure the HRSG is operating in compliance with Special Condition Nos. 1 and 5 until repairs can be made. **(2/12)**

If the concentration is greater than those required by Special Condition No. 5 for more than 24 hours, the holder shall notify the TCEQ DFW Regional Office either verbally or with a written report, detailing the cause of the increase in emissions and all efforts being made to correct the problem. If the CO concentration does not decrease to meet the requirements of Special Condition No. 5 within two weeks of the initial date of increase in CO concentrations, the holder shall commence with shutdown procedures.

C. When the average NH_3 outlet concentration from the SCR increases above 10 ppmv for more than one hour, the holder of this permit shall investigate and determine the reason for the increase in NH_3 concentrations and, if needed, repair the SCR and/or its associated equipment as soon as possible. The NH_3 concentration shall be corrected to 15 percent O_2. The holder of this permit will take appropriate steps, as necessary, to ensure the SCR unit is operating in compliance with Special Condition Nos. 1 and 9 until repairs can be made.

If the NH_3 concentration is not in compliance with Special Condition No. 9 for more than 24 hours, the holder shall notify the TCEQ DFW Regional Office either verbally or with a written report, detailing the cause of the increase in emissions and all efforts being made to correct the problem. If the NH_3 concentration does not decrease to meet the requirements of Special Condition No. 9 within two weeks of the initial date of increase in NH_3 concentrations, the holder shall commence with shutdown procedures.

22. The holder of this permit shall monitor the fuels fired in the equipment authorized by this permit for fuel-bound sulfur as specified in 40 CFR ' 60.334(b). Any request for a custom monitoring schedule shall be made in writing and directed to the Air Permits Division of the TCEQ although authority for granting such custom schedules remains with the EPA. Any custom schedule approved by EPA pursuant to 40 CFR ' 60.334(b) will be recognized as enforceable conditions of this permit provided that the holder of this permit demonstrates that the conditions of such custom schedule will be adequate to demonstrate continuous compliance with Special Condition Nos. 1 and 3.

Compliance and Maintenance

23. On an annual basis or during routine unit turnarounds, the low-NO_x duct burners of the HRSG shall be

visually inspected for erosion, corrosion, plugging, or any other alternation that may adversely affect low-NO_x performance. The TCEQ DFW Regional Office shall be notified at least seven days prior to the inspection in order to be given an opportunity to witness the inspection procedure.

24. A written description of any deviation from the monitoring required herein shall be made available to the TCEQ prior to the pretest meeting required in Special Condition No. 16. The TCEQ DFW Regional Director or the TCEQ Air Permits Division in Austin, and the EPA in Dallas shall approve or disapprove of any request for an alternate monitoring requirement. Such approval shall be obtained prior to the date required to conduct stack sampling under Special Condition No. 16.

Planned Maintenance, Startup, and Shutdown (MSS)

25. This permit authorizes the emissions from the planned MSS activities listed in Attachment A, or the MAERT attached to this permit. Attachment A identifies the inherently low emitting (ILE) planned maintenance activities that this permit authorizes to be performed. **(10/11)**

26. The emissions limits that are identified in Special Conditions 5A, 5B and 9 shall not apply during planned MSS activities. **(10/11)**

27. The holder of this permit shall minimize emissions during planned MSS activities by operating the facility and associated air pollution control equipment in accordance with good air pollution control practices, safe operating practices, and protection of the facility. **(10/11)**

28. Emissions during planned startup and shutdown activities will be minimized by limiting the duration of operation in planned startup and shutdown mode as follows: **(10/11)**

    A. A planned startup of the electric generating facility (EGF) with EPN No. E-CT/HRSG is defined as the period that begins when fuel is first fed to the unit and ends when the load on the unit reaches 120 MW. A planned startup for that EGF shall not exceed four hours.

    B. A planned shutdown of the EGF with EPN No. E-CT/HRSG is defined as the period that begins when the load on the unit drops below 120 MW and ends when fuel is no longer fed to the unit. A planned shutdown for that EGF shall not exceed two hours.

29. Compliance with the emissions limits for planned MSS activities identified in the MAERT attached to this permit may be demonstrated as follows. **(10/11)**

A. For each pollutant emitted during ILE planned maintenance activities, the permit holder shall annually confirm the continued validity of the estimated potential to emit represented in the permit application for all ILE planned maintenance activities. The total emissions from all ILE planned maintenance activities (See Attachment A) shall be considered to be no more than the estimated potential to emit for those activities that are represented in the permit application.

B. All other maintenance activities may be authorized by 30 TAC § 106.263.

30. With the exception of the emission limits in the MAERT attached to this permit, the permit conditions relating to planned MSS activities do not become effective until April 28, 2012. **(10/11)**

Recordkeeping Requirements

31. The following information shall be made and maintained by the holder of this permit in a form suitable for inspection for a period of two years and shall be made immediately available upon request to representatives of the TCEQ, EPA, or any local air pollution control program having jurisdiction:

A. Written records of any accidental releases, spills, or venting of NH_3 and the corrective action taken in accordance with Special Condition Nos. 10 and 11.

B. Written records of maintenance performed to any piping and valves in NH_3 service pursuant to Special Condition No. 12.

C. A complete copy of the testing report and records of the initial performance testing completed pursuant to Special Condition No. 16.

D. Records of the CEMS data required by Special Condition No. 17 to demonstrate continuous compliance with Special Condition No. 5.

E. Records of average hourly fuel and water consumption in the gas turbines pursuant to Special Condition No. 18.

F. Records of any NH_3 emissions calculations or testing performed during CEMS downtime pursuant to Special Condition No. 19

G. Calculations of predicted hourly NO_x, CO, and NH_3 emissions from the HRSG exhaust stacks when required by Special Condition No. 20.

H. Written records of any modifications or maintenance performed upon the equipment authorized by this permit.

I. Raw data files of all CEMS data including calibration checks and adjustments and maintenance performed on these systems of devices in a permanent form suitable for inspection.

J. Records of any maintenance or corrective action taken to maintain SCR performance pursuant to Special Condition No. 21.

K. Records of fuel sampling conducted pursuant to Special Condition No. 22 to demonstrate continuous compliance with Special Condition Nos. 1 and 3.

L. Written records of inspections conducted pursuant to Special Condition No. 23.

M. Field records of quarterly visible emission observations and opacity measurements (if applicable) as required by Special Condition No. 8. **(2/12)**

N. A log of all startups and shutdowns and durations to demonstrate compliance with Special Condition No. 28. **(10/11)**

Reporting

32. The holder of this permit shall submit to the TCEQ DFW 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. In addition to the information specified in 40 CFR ' 60.7(c), each report shall contain the hours of operation of the facility and a report summary of the periods of noncomplying emissions and CEMS downtimes by cause. Additionally, the report shall contain the duration, cause, and corrective action taken for any accidental release of NH_3.

33. For the purposes of reporting pursuant to Special Condition No. 32, noncomplying emissions from EPN E-CT/HRSG may be defined as follows:

A. Noncomplying emissions of NO_x or CO may be defined as each one-hour period of operation, except during planned MSS (defined as turbine operation at less than 120 MW, not to exceed four hours) during which the average emissions of NO_x or CO, as measured and recorded by the CEMS, exceed the emission limitations of Special Condition No. 5.

B. Noncomplying annual emissions of NO_x may be defined as a rolling 12-month period during which the 12-month cumulative emissions of NO_x exceed the annual limits specified in the table referenced in Special Condition No. 1.

C. Noncomplying emissions of NH_3 may be defined as each one-hour period of operation, except during planned MSS (defined as turbine operation at less than 120 MW, not to exceed four hours) during which the average emissions of NH_3 as measured and recorded by the CEMS, exceed the emission limitations of Special Condition No. 9.

D. For any period of operation except planned MSS during which the CEMS is unable to provide valid hourly emissions, noncomplying emissions of NO_x may be defined as each hourly period for which the predicted emissions of NO_x calculated in Special Condition No. 20 exceeds Special Condition No. 5.

E. For any period of operation except planned MSS during which the CEMS is unable to provide valid hourly emissions, noncomplying emissions of CO may be defined as each hourly period for which the predicted emissions of NO_x calculated in Special Condition No. 20 exceeds Special Condition No. 5.

F. For any period of operation except planned MSS during which the CEMS is unable to provide valid hourly emissions, noncomplying emissions of NH_3 may be defined as:

1. Each hourly period for which the predicted emissions of NH_3 calculated in Special Condition No. 20 that exceeds Special Condition No 1.

2. Any sample of which is found to contain NH_3 in excess of the limits of Special Condition

No. 9 or which indicates exceedance of the NH_3 limitation required in Special Condition No. 1.

G. Noncomplying emissions of SO_2 may be defined as fuel which is found to contain sulfur in excess of the limits of Special Condition No. 3 or which indicates exceedance of the SO_2 limitation required in Special Condition No. 1, based on 100 percent conversion of the sulfur in the fuel to SO_2.

Dated February 13, 2012

Attachment A

Permit No. 25384 and PSDTX839

Inherently Low Emitting (ILE) Planned Maintenance Activities

	Emissions				
Planned Maintenance Activity	NH_3	VOC	NO_x	CO	PM SO_2
Gaseous Venting and Line Purging	x	x			
Miscellaneous particulate filter maintenance[1]					x
CEMS Calibration	x		x	x	
Small Equipment Maintenance – Low Vapor Pressure VOC		x			
Sludge Management[2]		x			

Notes:

1. Includes, but is not limited to filters, process-related building air filters, and combustion turbine air intake filters.
2. Includes, but is not limited to, management by vacuum truck/dewatering of materials in sumps, tanks and other closed or open vessels. Materials managed include water and sludge mixtures containing miscellaneous VOCs such as diesel, lube oil, and other waste oils.

Headers

Special Conditions

Permit Numbers 25384 and PSDTX839

Page

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Attachment F

Permit No. O-00543
Issued May 15, 2012

Attachment G

BEPC's Application Submitted to Obtain TCEQ Permit No. 25384, PSDTX839

Bryan W. Shaw, Ph.D., *Chairman*
Carlos Rubinstein, *Commissioner*
Toby Baker, *Commissioner*
Zak Covar, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

May 15, 2012

MR MARK PAVELKA
MANAGER ENGINEERING SERVICES
BRAZOS ELECTRIC POWER COOPERATIVE, INC.
2404 LA SALLE AVE
WACO TX 76706-3928

Re: Effective Federal Operating Permit and Acid Rain Permit Approval
Renewal
Permit Number: O543
Brazos Electric Power Cooperative, Inc.
Johnson County Generation Facility
Cleborne, Johnson County
Regulated Entity Number: RN100223312
Customer Reference Number: CN600128821
Account Number: JH-0230-L

Dear Mr. Pavelka:

The effective federal operating permit (FOP) and acid rain permit for Brazos Electric Power Cooperative, Inc., Johnson County Generation Facility is enclosed. This FOP constitutes authority to operate the emission units identified in the FOP application.

All site operating permits are subject to public petition for 60 days following the expiration of the 45-day U.S. Environmental Protection Agency (EPA) review. The public petition period for the FOP extends from May 5, 2012 until July 3, 2012. If the EPA receives a valid petition and objects to the above-referenced permit, you will be notified promptly by the Texas Commission on Environmental Quality (TCEQ).

It should be noted that from the date of this letter Brazos Electric Power Cooperative, Inc., Johnson County Generation Facility must operate in accordance with the requirements of Title 30 Texas Administrative Code Chapter 122 (30 TAC Chapter 122) and the FOP. Some of the terms and conditions contained in the FOP include recordkeeping conditions, reporting conditions (which includes deviation reporting), and compliance certification conditions. All reports, along with any questions regarding the reports, shall be forwarded to the Texas Commission on Environmental Quality, Dallas/Fort Worth Regional Office, 2309 Gravel Drive, Fort Worth, Texas 76118-6951.

Consistent with 30 TAC Chapter 122, Subchapter C, the permit holder shall submit an application to the Air Permits Division (APD) for a revision to an FOP for those activities at a site which change, add, or remove one or more FOP terms or conditions. The permit holder shall also submit an application to the APD for a revision to a permit to address the following: the adoption of an applicable requirement previously designated as federally enforceable only;

the promulgation of a new applicable requirement; the adoption of a new state-only requirement; or a change in a state-only designation.

Thank you again for your cooperation in this matter. If you have questions concerning the review or this notice, please contact Ms. Camilla Widenhofer at (512) 239-1028.

This action is taken under authority delegated by the Executive Director of the TCEQ.

Sincerely,

Michael Wilson, P.E., Director
Air Permits Division
Office of Air
Texas Commission on Environmental Quality

MPW/cw

cc: Mr. Mickey Green, Environmental Specialist, Brazos Electric Power Cooperative, Inc., Waco
Mr. Mike Meyers, Environmental Manager, Brazos Electric Power Cooperative, Inc., Waco
Air Section Manager, Region 4 - Fort Worth

Enclosure: Effective Permit

cc: Air Permit Section Chief, U.S. Environmental Protection Agency, Region 6, Dallas

Project Number: 17151

FEDERAL OPERATING PERMIT

A FEDERAL OPERATING PERMIT IS HEREBY ISSUED TO

Brazos Electric Power Cooperative, Inc.

AUTHORIZING THE OPERATION OF

Johnson County Generation Facility
Electric Services

LOCATED AT

Johnson County, Texas

Latitude 32° 23' 57" Longitude 097° 24' 29"

Regulated Entity Number: RN100223312

This permit is issued in accordance with and subject to the Texas Clean Air Act (TCAA), Chapter 382 of the Texas Health and Safety Code and Title 30 Texas Administrative Code Chapter 122 (30 TAC Chapter 122), Federal Operating Permits. Under 30 TAC Chapter 122, this permit constitutes the permit holder's authority to operate the site, emission units and affected source listed in this permit. Operations of the site, emission units and affected source listed in this permit are subject to all additional rules or amended rules and orders of the Commission pursuant to the TCAA.

This permit does not relieve the permit holder from the responsibility of obtaining New Source Review authorization for new, modified, or existing facilities in accordance with 30 TAC Chapter 116, Control of Air Pollution by Permits for New Construction or Modification.

The site, emission units and affected source authorized by this permit shall be operated in accordance with 30 TAC Chapter 122, the general terms and conditions, special terms and conditions, and attachments contained herein.

This permit shall expire five years from the date of issuance. The renewal requirements specified in 30 TAC § 122.241 must be satisfied in order to renew the authorization to operate the site, emission units and affected source.

Permit No: O543 Issuance Date: May 15, 2012

For the Commission

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General Terms and Conditions

The permit holder shall comply with all terms and conditions contained in 30 TAC § 122.143 (General Terms and Conditions), 30 TAC § 122.144 (Recordkeeping Terms and Conditions), 30 TAC § 122.145 (Reporting Terms and Conditions), and 30 TAC § 122.146 (Compliance Certification Terms and Conditions).

In accordance with 30 TAC § 122.144(1), records of required monitoring data and support information required by this permit, or any applicable requirement codified in this permit, are required to be maintained for a period of five years from the date of the monitoring report, sample, or application unless a longer data retention period is specified in an applicable requirement. The five year record retention period supersedes any less stringent retention requirement that may be specified in a condition of a permit identified in the New Source Review Authorization attachment.

If the permit holder chooses to demonstrate that this permit is no longer required, a written request to void this permit shall be submitted to the Texas Commission on Environmental Quality (TCEQ) by the Responsible Official in accordance with 30 TAC § 122.161(e). The permit holder shall comply with the permit's requirements, including compliance certification and deviation reporting, until notified by the TCEQ that this permit is voided.

The permit holder shall comply with 30 TAC Chapter 116 by obtaining a New Source Review authorization prior to new construction or modification of emission units located in the area covered by this permit.

All reports required by this permit must include in the submittal a cover letter which identifies the following information: company name, TCEQ regulated entity number, air account number (if assigned), site name, area name (if applicable), and Air Permits Division permit number(s).

Special Terms and Conditions:
Emission Limitations and Standards, Monitoring and Testing, and Recordkeeping and Reporting

1. Permit holder shall comply with the following requirements:

   A. Emission units (including groups and processes) in the Applicable Requirements Summary attachment shall meet the limitations, standards, equipment specifications, monitoring, recordkeeping, reporting, testing, and other requirements listed in the Applicable Requirements Summary attachment to assure compliance with the permit.

   B. The textual description in the column titled "Textual Description" in the Applicable Requirements Summary attachment is not enforceable and is not deemed as a substitute for the actual regulatory language. The Textual Description is provided for information purposes only.

C. A citation listed on the Applicable Requirements Summary attachment, which has a notation [G] listed before it, shall include the referenced section and subsection for all commission rules, or paragraphs for all federal and state regulations and all subordinate paragraphs, subparagraphs and clauses, subclauses, and items contained within the referenced citation as applicable requirements.

D. When a grouped citation, notated with a [G] in the Applicable Requirements Summary, contains multiple compliance options, the permit holder must keep records of when each compliance option was used.

E. The permit holder shall comply with the applicable requirements of 40 CFR Part 63, Subpart ZZZZ as identified in the attached Applicable Requirements Summary by October 19, 2013.

2. The permit holder shall comply with the following sections of 30 TAC Chapter 101 (General Air Quality Rules):

A. Title 30 TAC § 101.1 (relating to Definitions), insofar as the terms defined in this section are used to define the terms used in other applicable requirements

B. Title 30 TAC § 101.3 (relating to Circumvention)

C. Title 30 TAC § 101.8 (relating to Sampling), if such action has been requested by the TCEQ

D. Title 30 TAC § 101.9 (relating to Sampling Ports), if such action has been requested by the TCEQ

E. Title 30 TAC § 101.10 (relating to Emissions Inventory Requirements)

F. Title 30 TAC § 101.201 (relating to Emission Event Reporting and Recordkeeping Requirements)

G. Title 30 TAC § 101.211 (relating to Scheduled Maintenance, Start-up, and Shutdown Reporting and Recordkeeping Requirements)

H. Title 30 TAC § 101.221 (relating to Operational Requirements)

I. Title 30 TAC § 101.222 (relating to Demonstrations)

J. Title 30 TAC § 101.223 (relating to Actions to Reduce Excessive Emissions)

3. Permit holder shall comply with the following requirements of 30 TAC Chapter 111:

A. Visible emissions from stationary vents with a flow rate of less than 100,000 actual cubic feet per minute and constructed after January 31, 1972 that are not listed in the Applicable Requirements Summary attachment for 30 TAC Chapter 111, Subchapter A, Division 1 , shall not exceed 20% opacity averaged

over a six-minute period. The permit holder shall comply with the following requirements for stationary vents at the site subject to this standard:

(i) Title 30 TAC § 111.111(a)(1)(B) (relating to Requirements for Specified Sources)

(ii) Title 30 TAC § 111.111(a)(1)(E)

(iii) Title 30 TAC § 111.111(a)(1)(F)(i), (ii), (iii), or (iv)

(iv) For emission units with vent emissions subject to 30 TAC § 111.111(a)(1)(B), complying with 30 TAC § 111.111(a)(1)(F)(ii), (iii), or (iv), and capable of producing visible emissions from, but not limited to, particulate matter, acid gases and NO_x, the permit holder shall also comply with the following periodic monitoring requirements for the purpose of annual compliance certification under 30 TAC § 122.146. These periodic monitoring requirements do not apply to vents that are not capable of producing visible emissions such as vents that emit only colorless VOCs; vents from non-fuming liquids; vents that provide passive ventilation, such as plumbing vents; or vent emissions from any other source that does not obstruct the transmission of light. Vents, as specified in the "Applicable Requirements Summary" attachment, that are subject to the emission limitation of 30 TAC § 111.111(a)(1)(B) and Compliance Assurance Monitoring (CAM), are not subject to the following periodic monitoring requirements and shall comply with the CAM requirements in the "Additional Monitoring Requirements" attachment:

(1) An observation of stationary vents from emission units in operation shall be conducted at least once during each calendar quarter unless the emission unit is not operating for the entire quarter.

(2) For stationary vents from a combustion source, if an alternative to the normally fired fuel is fired for a period greater than or equal to 24 consecutive hours, the permit holder shall conduct an observation of the stationary vent for each such period to determine if visible emissions are present. If such period is greater than 3 months, observations shall be conducted once during each quarter. Supplementing the normally fired fuel with natural gas or fuel gas to increase the net heating value to the minimum required value does not constitute creation of an alternative fuel.

(3) Records of all observations shall be maintained.

(4) Visible emissions observations of emission units operated during daylight hours shall be conducted no earlier than one hour after sunrise and no later than one hour before sunset. Visible emissions

observations of emission units operated only at night must be made with additional lighting and the temporary installation of contrasting backgrounds. Visible emissions observations shall be made during times when the activities described in 30 TAC § 111.111(a)(1)(E) are not taking place. Visible emissions shall be determined with each stationary vent in clear view of the observer. The observer shall be at least 15 feet, but not more than 0.25 mile, away from each stationary vent during the observation. For outdoor locations, the observer shall select a position where the sun is not directly in the observer's eyes. When condensed water vapor is present within the plume, as it emerges from the emissions outlet, observations must be made beyond the point in the plume at which condensed water vapor is no longer visible. When water vapor within the plume condenses and becomes visible at a distance from the emissions outlet, the observation shall be evaluated at the outlet prior to condensation of water vapor. A certified opacity reader is not required for visible emissions observations.

(5) Compliance Certification:

(a) If visible emissions are not present during the observation, the RO may certify that the source is in compliance with the applicable opacity requirement in 30 TAC § 111.111(a)(1) and (a)(1)(B).

(b) However, if visible emissions are present during the observation, the permit holder shall either list this occurrence as a deviation on the next deviation report as required under 30 TAC § 122.145(2) or conduct the appropriate opacity test specified in 30 TAC § 111.111(a)(1)(F) to determine if the source is in compliance with the opacity requirements. If an opacity test is performed and the source is determined to be in compliance, the RO may certify that the source is in compliance with the applicable opacity requirement. However, if an opacity test is performed and the source is determined to be out of compliance, the permit holder shall list this occurrence as a deviation on the next deviation report as required under 30 TAC § 122.145(2). The opacity test must be performed by a certified opacity reader.

(c) Some vents may be subject to multiple visible emission or monitoring requirements. All credible data must be considered when certifying compliance with this requirement even if the observation or monitoring was

performed to demonstrate compliance with a different requirement.

B. Certification of opacity readers determining opacities under Method 9 (as outlined in 40 CFR Part 60, Appendix A) to comply with opacity monitoring requirements shall be accomplished by completing the Visible Emissions Evaluators Course, or approved agency equivalent, no more than 180 days before the opacity reading.

C. For emission units with contributions from uncombined water, the permit holder shall comply with the requirements of 30 TAC § 111.111(b).

D. Emission limits on nonagricultural processes, except for the steam generators specified in 30 TAC § 111.153, shall comply with the following requirements:

(i) Emissions of PM from any source may not exceed the allowable rates as required in 30 TAC § 111.151(a) (relating to Allowable Emissions Limits)

(ii) Sources with an effective stack height (h_e) less than the standard effective stack height (H_e), must reduce the allowable emission level by multiplying it by $[h_e/H_e]^2$ as required in 30 TAC § 111.151(b)

(iii) Effective stack height shall be calculated by the equation specified in 30 TAC § 111.151(c)

E. Permit holder shall comply with the following requirements for steam generators:

(i) Emissions from any oil or gas fuel-fired steam generator with a heat input capacity greater than 2,500 MMBtu per hour may not exceed 0.1 pound of TSP per MMBtu of heat input, averaged over a two-hour period, as required in 30 TAC § 111.153(c) (relating to Emissions Limits for Steam Generators).

F. Outdoor burning, as stated in 30 TAC § 111.201, shall not be authorized unless the following requirements are satisfied:

(i) Title 30 TAC § 111.205 (relating to Exception for Fire Training)

(ii) Title 30 TAC § 111.221 (relating to Responsibility for Consequences of Outdoor Burning)

4. The permit holder shall comply with the following requirements for units subject to any subpart of 40 CFR Part 60, unless otherwise stated in the applicable subpart:

A. Title 40 CFR § 60.7 (relating to Notification and Recordkeeping)

B. Title 40 CFR § 60.8 (relating to Performance Tests)

C. Title 40 CFR § 60.11 (relating to Compliance with Standards and Maintenance Requirements)

D. Title 40 CFR § 60.12 (relating to Circumvention)

E. Title 40 CFR § 60.13 (relating to Monitoring Requirements)

F. Title 40 CFR § 60.14 (relating to Modification)

G. Title 40 CFR § 60.15 (relating to Reconstruction)

H. Title 40 CFR § 60.19 (relating to General Notification and Reporting Requirements)

5. The permit holder shall comply with the requirements of 30 TAC Chapter 113, Subchapter C, § 113.100 for units subject to any subpart of 40 CFR Part 63, unless otherwise stated in the applicable subpart.

Additional Monitoring Requirements

6. Unless otherwise specified, the permit holder shall comply with the compliance assurance monitoring requirements as specified in the attached "CAM Summary" upon issuance of the permit. In addition, the permit holder shall comply with the following:

A. The permit holder shall comply with the terms and conditions contained in 30 TAC § 122.147 (General Terms and Conditions for Compliance Assurance Monitoring).

B. The permit holder shall report, consistent with the averaging time identified in the "CAM Summary," deviations as defined by the deviation limit in the "CAM Summary." Any monitoring data below a minimum limit or above a maximum limit, that is collected in accordance with the requirements specified in 40 CFR § 64.7(c), shall be reported as a deviation. Deviations shall be reported according to 30 TAC § 122.145 (Reporting Terms and Conditions).

C. The permit holder may elect to collect monitoring data on a more frequent basis and average the data, consistent with the averaging time specified in the "CAM Summary," for purposes of determining whether a deviation has occurred. However, the additional data points must be collected on a regular basis. In no event shall data be collected and used in particular instances in order to avoid reporting deviations. All monitoring data shall be collected in accordance with the requirements specified in 40 CFR § 64.7(c).

D. The permit holder shall operate the monitoring, identified in the attached "CAM Summary," in accordance with the provisions of 40 CFR § 64.7.

E. The permit holder shall comply with the requirements of 40 CFR § 70.6(a)(3)(ii)(A) and 30 TAC § 122.144(1)(A)-(F) for documentation of all required inspections.

7. The permit holder shall comply with the periodic monitoring requirements as specified in the attached "Periodic Monitoring Summary" upon issuance of the permit. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the permit holder shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. The permit holder may elect to collect monitoring data on a more frequent basis and average the data, consistent with the averaging time specified in the "Periodic Monitoring Summary," for purposes of determining whether a deviation has occurred. However, the additional data points must be collected on a regular basis. In no event shall data be collected and used in particular instances to avoid reporting deviations. Deviations shall be reported according to 30 TAC § 122.145 (Reporting Terms and Conditions).

New Source Review Authorization Requirements

8. Permit holder shall comply with the requirements of New Source Review authorizations issued or claimed by the permit holder for the permitted area, including permits, permits by rule, standard permits, flexible permits, special permits, permits for existing facilities including Voluntary Emissions Reduction Permits and Electric Generating Facility Permits issued under 30 TAC Chapter 116, Subchapter I, or special exemptions referenced in the New Source Review Authorization References attachment. These requirements:

   A. Are incorporated by reference into this permit as applicable requirements

   B. Shall be located with this operating permit

   C. Are not eligible for a permit shield

9. The permit holder shall comply with the general requirements of 30 TAC Chapter 106, Subchapter A or the general requirements, if any, in effect at the time of the claim of any PBR.

10. The permit holder shall maintain records to demonstrate compliance with any emission limitation or standard that is specified in a permit by rule (PBR) or Standard Permit listed in the New Source Review Authorizations attachment. The records shall yield reliable data from the relevant time period that are representative of the emission unit's compliance with the PBR or Standard Permit. These records may include, but are not limited to, production capacity and throughput, hours of operation, material safety data sheets (MSDS), chemical composition of raw materials, speciation of air contaminant data, engineering calculations, maintenance records, fugitive data, performance tests,

capture/control device efficiencies, direct pollutant monitoring (CEMS, COMS, or PEMS), or control device parametric monitoring. These records shall be made readily accessible and available as required by 30 TAC § 122.144.

A. If applicable, monitoring of control device performance or general work practice standards shall be made in accordance with the TCEQ Periodic Monitoring Guidance document.

B. Any monitoring or recordkeeping data indicating noncompliance with the PBR or Standard Permit shall be considered and reported as a deviation according to 30 TAC § 122.145 (Reporting Terms and Conditions).

Compliance Requirements

11. The permit holder shall certify compliance in accordance with 30 TAC § 122.146. The permit holder shall comply with 30 TAC § 122.146 using at a minimum, but not limited to, the continuous or intermittent compliance method data from monitoring, recordkeeping, reporting, or testing required by the permit and any other credible evidence or information. The certification period may not exceed 12 months and the certification must be submitted within 30 days after the end of the period being certified.

12. Permit holder shall comply with the following 30 TAC Chapter 117 requirements:

    A. The permit holder shall comply with the compliance schedules and submit written notification to the Executive Director as required in 30 TAC Chapter 117, Subchapter H, Division 1:

        (i) For electric utilities in the Dallas-Fort Worth Eight-Hour Nonattainment area, 30 TAC § 117.9130

    B. The permit holder shall comply with the compliance schedules and submit written notification to the TCEQ Executive Director as required in 30 TAC Chapter 117, Subchapter H, Division 1:

        (i) For sources in the Dallas-Fort Worth Eight-Hour Nonattainment area, 30 TAC § 117.9030

    C. The permit holder shall comply with the Initial Control Plan unit identification requirements in 30 TAC § 117.450(a) and (a)(1).

    D. The permit holder shall comply with the requirements of 30 TAC § 117.454 for Final Control Plan Procedures for Attainment Demonstration Emission Specifications and 30 TAC § 117.456 for Revision of Final Control Plan.

13. Use of Emission Credits to comply with applicable requirements:

A. Unless otherwise prohibited, the permit holder may use emission credits to comply with the following applicable requirements listed elsewhere in this permit:

(i) Title 30 TAC Chapter 115

(ii) Title 30 TAC Chapter 117

(iii) Offsets for Title 30 TAC Chapter 116

B. The permit holder shall comply with the following requirements in order to use the emission credits to comply with the applicable requirements:

(i) The permit holder must notify the TCEQ according to 30 TAC § 101.306(c)(2)

(ii) The emission credits to be used must meet all the geographic, timeliness, applicable pollutant type, and availability requirements listed in 30 TAC Chapter 101, Subchapter H, Division 1

(iii) The executive director has approved the use of the credit according to 30 TAC § 101.306(c)(2)

(iv) The permit holder keeps records of the use of credits towards compliance with the applicable requirements in accordance with 30 TAC § 101.302(g) and 30 TAC Chapter 122

14. Use of Discrete Emission Credits to comply with the applicable requirements:

A. Unless otherwise prohibited, the permit holder may use discrete emission credits to comply with the following applicable requirements listed elsewhere in this permit:

(i) Title 30 TAC Chapter 115

(ii) Title 30 TAC Chapter 117

(iii) If applicable, offsets for Title 30 TAC Chapter 116

(iv) Temporarily exceed state NSR permit allowables

B. The permit holder shall comply with the following requirements in order to use the credit to comply with the applicable requirements:

(i) The permit holder must notify the TCEQ according to 30 TAC § 101.376(d)

(ii) The discrete emission credits to be used must meet all the geographic, timeliness, applicable pollutant type, and availability requirements listed in 30 TAC Chapter 101, Subchapter H, Division 4

(iii) The executive director has approved the use of the discrete emission credits according to 30 TAC § 101.376(d)(1)(A)

(iv) The permit holder keeps records of the use of credits towards compliance with the applicable requirements in accordance with 30 TAC § 101.372(h) and 30 TAC Chapter 122

Risk Management Plan

15. For processes subject to 40 CFR Part 68 and specified in 40 CFR § 68.10, the permit holder shall comply with the requirements of the Accidental Release Prevention Provisions in 40 CFR Part 68. The permit holder shall submit to the appropriate agency either a compliance schedule for meeting the requirements of 40 CFR Part 68 by the date provided in 40 CFR § 68.10(a), or as part of the compliance certification submitted under this permit, a certification statement that the source is in compliance with all requirements of 40 CFR Part 68, including the registration and submission of a risk management plan.

Protection of Stratospheric Ozone

16. Permit holders at a site subject to Title VI of the FCAA Amendments shall meet the following requirements for protection of stratospheric ozone.

A. Any on site servicing, maintenance, and repair on refrigeration and nonmotor vehicle air-conditioning appliances using ozone-depleting refrigerants or non-exempt substitutes shall be conducted in accordance with 40 CFR Part 82, Subpart F. Permit holders shall ensure that repairs on or refrigerant removal from refrigeration and nonmotor vehicle air-conditioning appliances using ozone-depleting refrigerants are performed only by properly certified technicians using certified equipment. Records shall be maintained as required by 40 CFR Part 82, Subpart F.

B. The permit holder shall comply with 40 CFR Part 82, Subpart A for controlling the production, transformation, destruction, export or import of a controlled (ozone-depleting) substance or product as specified in 40 CFR § 82.1 - § 82.13 and the applicable Part 82 Appendices.

C. The permit holder shall comply with 40 CFR Part 82, Subpart A, § 82.13 related to recordkeeping and reporting requirements for the production and consumption of ozone depleting substances.

Temporary Fuel Shortages (30 TAC § 112.15)

17. The permit holder shall comply with the following 30 TAC Chapter 112 requirements:

    A. Title 30 TAC § 112.15 (relating to Temporary Fuel Shortage Plan Filing Requirements)

    B. Title 30 TAC § 112.16(a), (a)(1), and (a)(2)(B) - (c) (relating to Temporary Fuel Shortage Plan Operating Requirements)

    C. Title 30 TAC § 112.17 (relating to Temporary Fuel Shortage Plan Notification Procedures)

    D. Title 30 TAC § 112.18 (relating to Temporary Fuel Shortage Plan Reporting Requirements)

Permit Location

18. The permit holder shall maintain a copy of this permit and records related to requirements listed in this permit on site.

Permit Shield (30 TAC § 122.148)

19. A permit shield is granted for the emission units, groups, or processes specified in the attached "Permit Shield." Compliance with the conditions of the permit shall be deemed compliance with the specified potentially applicable requirements or specified potentially applicable state-only requirements listed in the attachment "Permit Shield." Permit shield provisions shall not be modified by the executive director until notification is provided to the permit holder. No later than 90 days after notification of a change in a determination made by the executive director, the permit holder shall apply for the appropriate permit revision to reflect the new determination. Provisional terms are not eligible for this permit shield. Any term or condition, under a permit shield, shall not be protected by the permit shield if it is replaced by a provisional term or condition or the basis of the term and condition changes.

Acid Rain Permit Requirements

20. For unit E-GT (identified in the Certificate of Representation as unit EAST), located at the affected source identified by ORIS/Facility code 54817, the designated representative and the owner or operator, as applicable, shall comply with the following Acid Rain Permit requirements.

    A. General Requirements

        (i) Under 30 TAC § 122.12(1) and 40 CFR Part 72, the Acid Rain Permit requirements contained here are a separable portion of the Federal

Operating Permit (FOP) and have an independent public comment process which may be separate from, or combined with the FOP.

(ii) The owner and operator shall comply with the requirements of 40 CFR Part 72 and 40 CFR Part 76. Any noncompliance with the Acid Rain Permit will be considered noncompliance with the FOP and may be subject to enforcement action.

(iii) The owners and operators of the affected source shall operate the source and the unit in compliance with the requirements of this Acid Rain Permit and all other applicable State and federal requirements.

(iv) The owners and operators of the affected source shall comply with the General Terms and Conditions of the FOP that incorporates this Acid Rain Permit.

(v) The term for the Acid Rain permit shall commence with the issuance of the FOP that incorporates the Acid Rain permit and shall be run concurrent with the remainder of the term of the FOP. Renewal of the Acid Rain permit shall coincide with the renewal of the FOP that incorporates the Acid Rain permit and subsequent terms shall be no more than five years from the date of renewal of the FOP and run concurrent with the permit term of the FOP.

B. Monitoring Requirements

(i) The owners and operators, and the designated representative, of the affected source and each affected unit at the source shall comply with the monitoring requirements contained 40 CFR Part 75.

(ii) The emissions measurements recorded and reported in accordance with 40 CFR Part 75 and any other credible evidence shall be used to determine compliance by the affected source with the acid rain emissions limitations and emissions reduction requirements for SO_2 and NO_x under the ARP.

(iii) The requirements of 40 CFR Part 75 shall not affect the responsibility of the owners and operators to monitor emission of other pollutants or other emissions characteristics at the unit under other applicable requirements of the FCAA Amendments (42 U.S.C. 7401, as amended November 15, 1990) and other terms and conditions of the operating permit for the source.

C. SO_2 emissions requirements

(i) The owners and operators of each source and each affected unit at the source shall comply with the applicable acid rain emissions limitations for SO_2.

(ii) As of the allowance transfer deadline the owners and operators of the affected source and each affected unit at the source shall hold, in the unit's compliance subaccount, allowances in an amount not less than the total annual emissions of SO_2 for the previous calendar year.

(iii) Each ton of SO_2 emitted in excess of the acid rain emissions limitations for SO_2 shall constitute a separate violation of the FCAA amendments.

(iv) An affected unit shall be subject to the requirements under (i) and (ii) of the SO_2 emissions requirements as follows:

(1) Starting January 1, 2000, an affected unit under 40 CFR § 72.6(a)(2); or

(2) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR Part 75, an affected unit under 40 CFR § 72.6(a)(3).

(v) Allowances shall be held in, deducted from, or transferred into or among Allowance Tracking System accounts in accordance with the requirements of the ARP.

(vi) An allowance shall not be deducted, for compliance with the requirements of this permit, in a calendar year before the year for which the allowance was allocated.

(vii) An allowance allocated by the EPA Administrator or under the ARP is a limited authorization to emit SO_2 in accordance with the ARP. No provision of the ARP, Acid Rain permit application, this Acid Rain Permit, or an exemption under 40 CFR §§ 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(viii) An allowance allocated by the EPA Administrator under the ARP does not constitute a property right.

D. NO_x Emission Requirements

(i) The owners and operators of the source and each affected unit at the source shall comply with the applicable acid rain emissions limitations for NO_x under 40 CFR Part 76.

E. Excess emissions requirements for SO_2 and NO_x.

(i) The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR Part 77.

(ii) If an affected source has excess emissions in any calendar year shall, as required by 40 CFR Part 77:

(1) Pay, without demand, the penalty required and pay, upon demand, the interest on that penalty.

(2) Comply with the terms of an approved offset plan.

F. Recordkeeping and Reporting Requirements

(i) Unless otherwise provided, the owners and operators of the affected source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the EPA Administrator.

(1) The certificate of representation for the designated representative for the source and each affected unit and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR § 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative.

(2) All emissions monitoring information, in accordance with 40 CFR Part 75, provided that to the extent that 40 CFR Part 75 provides for a 3-year period for recordkeeping (rather than a five-year period cited in 30 TAC § 122.144), the 3-year period shall apply.

(3) Copies of all reports, compliance certifications, and other submissions and all records made or required under the ARP or relied upon for compliance certification.

(4) Copies of all documents used to complete a acid rain permit application and any other submission under the ARP or to demonstrate compliance with the requirements of the ARP.

(ii) The designated representative of an affected source and each affected unit at the source shall submit the reports required under the ARP including those under 40 CFR Part 72, Subpart I and 40 CFR Part 75.

G. Liability

(i) Any person who knowingly violates any requirement or prohibition of the ARP, a complete acid rain permit application, an acid rain permit, or a

written exemption under 40 CFR §§ 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to FCAA § 113(c).

(ii) Any person who knowingly makes a false, material statement in any record, submission, or report under the ARP shall be subject to criminal enforcement pursuant to FCAA § 113(c) and 18 U.S.C. 1001.

(iii) No permit revision shall excuse any violation of the requirements of the ARP that occurs prior to the date that the revision takes effect.

(iv) The affected source and each affected unit shall meet the requirements of the ARP contained in 40 CFR Parts 72 through 78.

(v) Any provision of the ARP that applies to an affected source or the designated representative of an affected source shall also apply to the owners and operators of such source and of the affected units at the source.

(vi) Any provision of the ARP that applies to an affected unit (including a provision applicable to the DR of an affected unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR § 72.44 (Phase II repowering extension plans) and 40 CFR § 76.11 (NO_x averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR Part 75 (including 40 CFR §§ 75.16, 75.17, and 75.18), the owners and operators and the DR of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the DR and that is located at a source of which they are not owners or operators or the DR.

(vii) Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or DR of such source or unit, shall be a separate violation of the FCAA Amendments.

H. Effect on other authorities. No provision of the ARP, an acid rain permit application, an acid rain permit, or an exemption under 40 CFR §§ 72.7 or 72.8 shall be construed as:

(i) Except as expressly provided in Title IV of the FCAA Amendments, exempting or excluding the owners and operators and, to the extent applicable, the DR of an affected source or affected unit from compliance with any other provision of the FCAA Amendments, including the provisions of Title I of the FCAA Amendments relating to applicable National Ambient Air Quality Standards or State Implementation Plans.

(ii) Limiting the number of allowances a unit can hold; provided, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the FCAA Amendments.

(iii) Requiring a change of any kind in any state law regulating electric utility rates and charges, affecting any state law regarding such state regulation, or limiting such state regulation, including any prudence review requirements under such state law.

(iv) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(v) Interfering with or impairing any program for competitive bidding for power supply in a state in which such program is established.

I. The number of SO_2 allowances allocated by the EPA in 40 CFR Part 73 is enforceable only by the EPA Administrator.

Clean Air Interstate Rule Permit Requirements

21. For unit E-GT (identified in the Certificate of Representation as unit EAST), located at the site identified by ORIS/Facility code 54817, the designated representative and the owner or operator, as applicable, shall comply with the following Clean Air Interstate Rule (CAIR) Permit requirements. Until approval of the Texas CAIR SIP by EPA, the permit holder shall comply with the equivalent requirements of 40 CFR Part 97 in place of the referenced 40 CFR Part 96 requirements in the Texas CAIR permit and 30 TAC Chapter 122 requirements.

A. General Requirements

(i) Under 30 TAC § 122.420(b) and 40 CFR §§ 96.120(b) and 96.220(b) the CAIR Permit requirements contained here are a separable portion of the Federal Operating Permit (FOP).

(ii) The owners and operators of the CAIR NO_x and the CAIR SO_2 source shall operate the source and the unit in compliance with the requirements of this CAIR permit and all other applicable State and federal requirements.

(iii) The owners and operators of the CAIR NO_x and the CAIR SO_2 source shall comply with the General Terms and Conditions of the FOP that incorporates this CAIR Permit.

(iv) The term for the initial CAIR permit shall commence with the issuance of the revision containing the CAIR permit and shall be the remaining term for the FOP that incorporates the CAIR permit. Renewal of the initial CAIR permit shall coincide with the renewal of the FOP that incorporates

the CAIR permit and subsequent terms shall be no more than five years from the date of renewal of the FOP and run concurrent with the permit term of the FOP.

B. Monitoring and Reporting Requirements

(i) The owners and operators, and the CAIR designated representative, of the CAIR NO_x source and each CAIR NO_x unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements contained 40 CFR Part 96, Subpart HH.

(ii) The owners and operators, and the CAIR designated representative, of the CAIR SO_2 source and each CAIR SO_2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements contained 40 CFR Part 96, Subpart HHH.

(iii) The emissions measurements recorded and reported in accordance with 40 CFR Part 96, Subpart HH and any other credible evidence shall be used to determine compliance by the CAIR NO_x source with the CAIR NO_x emissions limitation.

(iv) The emissions measurements recorded and reported in accordance with 40 CFR Part 96, Subpart HHH and any other credible evidence shall be used to determine compliance by the CAIR SO_2 source with the CAIR SO_2 emissions limitation.

C. NO_x emissions requirements

(i) As of the allowance transfer deadline for a control period, the owners and operators of the CAIR NO_x source and each CAIR NO_x unit at the source shall hold, in the source's compliance account, CAIR NO_x allowances available for compliance deductions for the control period under 40 CFR § 96.154(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_x units at the source, as determined in accordance the requirements 40 CFR Part 96, Subpart HH.

(ii) A CAIR NO_x unit shall be subject to the requirements of paragraph C.(i) of this CAIR Permit starting on the later of January 1, 2009, or the deadline for meeting the unit's monitor certification requirements under 40 CFR § 96.170(b)(1), (2), or (5).

(iii) A CAIR NO_x allowance shall not be deducted, for compliance with the requirements of this permit, for a control period in a calendar year before the year for which the CAIR NO_x allowance was allocated.

(iv) CAIR NO_x allowances shall be held in, deducted from or transferred into or among CAIR NO_x Allowance Tracking System accounts in accordance with the requirements of 40 CFR Part 96, Subpart FF or Subpart GG.

(v) A CAIR NO_x allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO_x Annual Trading Program. No provision of the CAIR NO_x Annual Trading Program, the CAIR permit application, the CAIR permit, or an exemption under 40 CFR § 96.105 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(vi) A CAIR NO_x allowance does not constitute a property right.

(vii) Upon recordation by the Administrator under 40 CFR Part 96, Subpart FF or Subpart GG, every allocation, transfer, or deduction of a CAIR NO_x allowance to or from a CAIR NO_x unit's compliance account is incorporated automatically in this CAIR permit.

D. NO_x excess emissions requirement

(i) If a CAIR NO_x source emits nitrogen oxides during any control period in excess of the CAIR NO_x emissions limitation, the owners and operators of the source and each CAIR NO_x unit at the source shall surrender the CAIR NO_x allowances required for deduction under 40 CFR § 96.154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law.

(ii) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 96, Subpart AA, the Clean Air Act, and applicable State law.

E. SO_2 emissions requirements

(i) As of the allowance transfer deadline for a control period, the owners and operators of the CAIR SO_2 source and each CAIR SO_2 unit at the source shall hold, in the source's compliance account, CAIR SO_2 allowances available for compliance deductions for the control period under 40 CFR § 96.254(a) and (b) in an amount not less than the tons of total sulfur dioxides emissions for the control period from all CAIR SO_2 units at the source, as determined in accordance the requirements 40 CFR Part 96, Subpart HHH.

(ii) A CAIR SO_2 unit shall be subject to the requirements of paragraph E.(i) of this CAIR Permit starting on the later of January 1, 2010, or the deadline

for meeting the unit's monitor certification requirements under 40 CFR § 96.270(b)(1), (2), or (5).

(iii) A CAIR SO_2 allowance shall not be deducted, for compliance with the requirements of this permit, for a control period in a calendar year before the year for which the CAIR SO_2 allowance was allocated.

(iv) CAIR SO_2 allowances shall be held in, deducted from, or transferred into or among CAIR SO_2 Allowance Tracking System accounts in accordance with the requirements of 40 CFR Part 96, Subpart FFF or Subpart GGG.

(v) A CAIR SO_2 allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO_2 Trading Program. No provision of the CAIR SO_2 Trading Program, the CAIR permit application, the CAIR permit, or an exemption under 40 CFR § 96.205 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(vi) A CAIR SO_2 allowance does not constitute a property right.

(vii) Upon recordation by the Administrator under 40 CFR Part 96, Subpart FFF or Subpart GGG, every allocation, transfer, or deduction of a CAIR SO_2 allowance to or from a CAIR SO_2 unit's compliance account is incorporated automatically in this CAIR permit.

F. SO_2 excess emissions requirements

(i) If a CAIR SO_2 source emits sulfur dioxides during any control period in excess of the CAIR SO_2 emissions limitation, the owners and operators of the source and each CAIR SO_2 unit at the source shall surrender the CAIR SO_2 allowances required for deduction under 40 CFR § 96.254(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law.

(ii) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 96, Subpart AAA, the Clean Air Act, and applicable State law.

G. Recordkeeping and Reporting Requirements

(i) Unless otherwise provided, the owners and operators of the CAIR NO_x source and each CAIR NO_x unit at the source and the CAIR SO_2 source and each CAIR SO_2 unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time

before the end of 5 years, in writing by the permitting authority or the Administrator.

(1) The certificate of representation under 40 CFR §§ 96.113 and 96.213 for the CAIR NO_x designated representative for the source and each CAIR NO_x unit and the CAIR SO_2 designated representative for the source and each CAIR SO_2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5 year period until such documents are superseded because of the submission of a new certificate of representation under 40 CFR §§ 96.113 and 96.213 changing the CAIR designated representative.

(2) All emissions monitoring information, in accordance with 40 CFR Part 96, Subpart HH and Subpart HHH, provided that to the extent that these subparts provide for a 3-year period for recordkeeping, the 3-year period shall apply.

(3) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_x Annual Trading Program and CAIR SO_2 Trading Program or relied upon for compliance determinations.

(4) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_x Annual Trading Program and CAIR SO_2 Trading Program or to demonstrate compliance with the requirements of the CAIR NO_x Annual Trading Program and CAIR SO_2 Trading Program.

(ii) The CAIR designated representative of a CAIR NO_x source and each CAIR NO_x unit at the source and a CAIR SO_2 source and each CAIR SO_2 unit at the source shall submit the reports required under the CAIR NO_x Annual Trading Program and the CAIR SO_2 Trading Program including those under 40 CFR Part 96, Subpart HH and Subpart HHH.

H. The CAIR NO_x source and each CAIR NO_x unit shall meet the requirements of the CAIR NO_x Annual Trading Program contained in 40 CFR Part 96, Subparts AA through II.

I. The CAIR SO_2 source and each CAIR SO_2 unit shall meet the requirements of the CAIR SO_2 Trading Program contained in 40 CFR Part 96, Subparts AAA through III.

J. Any provision of the CAIR NO_x Annual Trading Program and the CAIR SO_2 Trading Program that applies to a CAIR NO_x source or CAIR SO_2 source or the CAIR designated representative of a CAIR NO_x source or CAIR SO_2 source shall also apply to the owners and operators of such source and the units at the source.

K. Any provision of the CAIR NO_x Annual Trading Program and the CAIR SO_2 Trading Program that applies to a CAIR NO_x unit or CAIR SO_2 unit or the CAIR designated representative of a CAIR NO_x unit or CAIR SO_2 unit shall also apply to the owners and operators of such unit.

L. No provision of the CAIR NO_x Annual Trading Program, CAIR SO_2 Trading Program, a CAIR permit application, a CAIR permit, or an exemption under 40 CFR §§ 96.105 or 96.205 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_x source or CAIR NO_x unit or a CAIR SO_2 source or CAIR SO_2 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

Attachments

Applicable Requirements Summary

Additional Monitoring Requirements

Permit Shield

New Source Review Authorization References

Applicable Requirements Summary

Unit Summary 24

Applicable Requirements Summary 25

Note: A "none" entry may be noted for some emission sources in this permit's "Applicable Requirements Summary" under the heading of "Monitoring and Testing Requirements" and/or "Recordkeeping Requirements" and/or "Reporting Requirements." Such a notation indicates that there are no requirements for the indicated emission source as identified under the respective column heading(s) for the stated portion of the regulation when the emission source is operating under the conditions of the specified SOP Index Number. However, other relevant requirements pursuant to 30 TAC Chapter 122 including Recordkeeping Terms and Conditions (30 TAC § 122.144), Reporting Terms and Conditions (30 TAC § 122.145), and Compliance Certification Terms and Conditions (30 TAC § 122.146) continue to apply.

Unit Summary

Unit/Group/ Process ID No.	Unit Type	Group/Inclusive Units	SOP Index No.	Regulation	Requirement Driver
E-HRSG	BOILERS/STEAM GENERATORS/STEAM GENERATING UNITS	N/A	NG1	40 CFR Part 60, Subpart Da	No changing attributes.
FO-LOAD1	LOADING/UNLOADING OPERATIONS	N/A	FO-115	30 TAC Chapter 115, Loading and Unloading of VOC	No changing attributes.
FP-1	SRIC ENGINES	N/A	63ZZZZ	40 CFR Part 63, Subpart ZZZZ	No changing attributes
E-GT	STATIONARY TURBINES	N/A	FO1	40 CFR Part 60, Subpart GG	FUEL SUPPLY = Stationary gas turbine is supplied its fuel from a bulk storage tank, FUEL TYPE FIRED = Liquid fuel
E-GT	STATIONARY TURBINES	N/A	NG2	40 CFR Part 60, Subpart GG	FUEL SUPPLY = Stationary gas turbine is supplied its fuel without intermediate bulk storage tank, FUEL TYPE FIRED = Natural gas meeting the definition in § 60.331(u).
OIL-TK	STORAGE TANKS/VESSELS	N/A	115-FOT	30 TAC Chapter 115, Storage of VOCs	No changing attributes.

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
E-HRSG	EU	NG1	PM(OPACITY)	40 CFR Part 60, Subpart Da	§ 60.42Da(b) § 60.48Da(c)	No owner or operator shall discharge any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators that elect to install, calibrate, maintain and operate a CEMS for measuring PM emissions are exempt from the opacity standard.	§ 60.48Da(q) § 60.49Da(a)(3) § 60.50Da(a) § 60.50Da(b)(3) [G]§ 60.50Da(c)	[G]§ 60.52Da(b)	[G]§ 60.51Da(h) § 60.51Da(j)
E-HRSG	EU	NG1	PM	40 CFR Part 60, Subpart Da	§ 60.42Da(a)(1) § 60.48Da(c)	No owner or operator discharge any gases that contain PM in excess of 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.	§ 60.50Da(a) § 60.50Da(b)(1) [G]§ 60.50Da(b)(2) [G]§ 60.50Da(c) § 60.50Da(f) ** See Periodic Monitoring Summary	None	§ 60.51Da(a) [G]§ 60.51Da(h) § 60.51Da(j)
E-HRSG	EU	NG1	NOx	40 CFR Part 60, Subpart Da	[G]§ 60.44Da(a) § 60.48Da(c)	No owner or operator shall discharge any gases that contain NOx (expressed as NO2) in excess of the specified emission limits in §60.44Da(a)(1) and (a)(2), based on a 30-day rolling average basis. §60.44Da(a)(1)-(2)	§ 60.48Da(c) § 60.48Da(f) § 60.48Da(g)(1) § 60.48Da(h) § 60.48Da(j)(2) § 60.49Da(c)(2) § 60.49Da(d) § 60.49Da(e) § 60.49Da(f)(1) § 60.49Da(h) § 60.49Da(h)(2) § 60.49Da(h)(3) § 60.49Da(h)(4) § 60.49Da(i)(3)(ii) § 60.49Da(i)(4) § 60.49Da(j)(2) § 60.49Da(j)(3) § 60.49Da(j)(4) [G]§ 60.49Da(s)	[G]§ 60.49Da(s) [G]§ 60.49Da(w)	[G]§ 60.49Da(s) [G]§ 60.49Da(w) § 60.51Da(a) § 60.51Da(b) § 60.51Da(b)(1) § 60.51Da(b)(2) § 60.51Da(b)(4) § 60.51Da(b)(5) § 60.51Da(b)(6) § 60.51Da(b)(7) § 60.51Da(b)(8) § 60.51Da(b)(9) [G]§ 60.51Da(c) § 60.51Da(f) [G]§ 60.51Da(h) § 60.51Da(j) § 60.51Da(k)

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
							[G]§ 60.49Da(w) § 60.50Da(a) [G]§ 60.50Da(d) [G]§ 60.50Da(e) § 60.50Da(f)		
E-HRSG	EU	NG1	SO_2	40 CFR Part 60, Subpart Da	§ 60.43Da(b)(2) § 60.43Da(g) § 60.48Da(c)	No owner or operator shall discharge any gases that contain sulfur dioxide in excess of 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/MMBtu) heat input.	§ 60.48Da(e) § 60.48Da(f) § 60.48Da(g)(1) § 60.48Da(h) § 60.49Da(j)(1) § 60.49Da(j)(3) § 60.49Da(j)(4) § 60.50Da(a) [G]§ 60.50Da(c) [G]§ 60.50Da(e) § 60.50Da(f) ** See Periodic Monitoring Summary	None	§ 60.51Da(a) § 60.51Da(b) § 60.51Da(b)(1) § 60.51Da(b)(2) § 60.51Da(b)(4) § 60.51Da(b)(5) § 60.51Da(b)(6) § 60.51Da(b)(7) [G]§ 60.51Da(c) [G]§ 60.51Da(d) [G]§ 60.51Da(e) § 60.51Da(f) [G]§ 60.51Da(h) § 60.51Da(j) § 60.51Da(k)
FO-LOAD1	EU	FO-115	VOC	30 TAC Chapter 115, Loading and Unloading of VOC	§ 115.217(a)(1) § 115.212(a)(2) [G]§ 115.212(a)(7) § 115.214(a)(1)(B) § 115.214(a)(1)(D) § 115.214(a)(1)(D)(i)	Vapor pressure (at land-based operations). All land-based loading and unloading of VOC with a true vapor pressure less than 0.5 psia is exempt from the requirements of this division, except as specified.	§ 115.214(a)(1)(A) § 115.214(a)(1)(A)(i) § 115.215 § 115.215(4)	§ 115.216 § 115.216(2) § 115.216(3)(B)	None
FP-1	EU	63ZZZZ	HAPS	40 CFR Part 63, Subpart ZZZZ	§ 63.6603(a)-Table 2d.4 § 63.6595(a)(1) § 63.6605(a) § 63.6605(b) § 63.6625(e) § 63.6625(h) § 63.6625(i) § 63.6640(b) § 63.6640(f)(1)	For each existing emergency stationary CI RICE and black start stationary CI RICE, located at an area source, you must comply with the requirements as specified in Table 2d.4.a-c.	§ 63.6625(f) § 63.6625(i) § 63.6640(a) § 63.6640(a)-Table 6.9.a.i § 63.6640(a)-Table 6.9.a.ii § 63.6640(b)	§ 63.6625(i) § 63.6655(a) § 63.6655(a)(1) § 63.6655(a)(2) § 63.6655(a)(4) § 63.6655(a)(5) § 63.6655(d) § 63.6655(e) § 63.6655(f) § 63.6660(a)	§ 63.6640(b) § 63.6640(e) § 63.6645(a)(5) § 63.6650(f) § 63.6665

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
								§ 63.6660(b) § 63.6660(c) § 63.6665	
E-GT	EU	FO1	SO2	40 CFR Part 60, Subpart GG	§ 60.333(b)	No stationary gas turbine shall burn any fuel which contains sulfur in excess of 0.8% by weight.	§ 60.334(h) § 60.334(h)(4)	None	None
E-GT	EU	FO1	NOX	40 CFR Part 60, Subpart GG	§ 60.332(a)(1) § 60.332(a)(3) § 60.332(f) § 60.332(i)	No owner or operator shall discharge into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of the amount as determined from the specified equation.	[G]§ 60.334(b) § 60.334(j) § 60.334(j)(1) [G]§ 60.334(j)(1)(iii) [G]§ 60.335(a) § 60.335(b)(2) § 60.335(b)(3)	[G]§ 60.334(b)	§ 60.334(j) § 60.334(j)(3) § 60.334(j)(5)
E-GT	EU	NG2	SO2	40 CFR Part 60, Subpart GG	§ 60.333(b)	No stationary gas turbine shall burn any fuel which contains sulfur in excess of 0.8% by weight.	§ 60.334(h) § 60.334(h)(4)	None	None
E-GT	EU	NG2	NOX	40 CFR Part 60, Subpart GG	§ 60.332(a)(1) § 60.332(a)(3) § 60.332(f) § 60.332(i)	No owner or operator shall discharge into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of the amount as determined from the specified equation.	[G]§ 60.334(b) § 60.334(j) § 60.334(j)(1) [G]§ 60.334(j)(1)(iii) [G]§ 60.335(a) § 60.335(b)(2) § 60.335(b)(3) ** See CAM Summary	[G]§ 60.334(b)	§ 60.334(j) § 60.334(j)(3) § 60.334(j)(5)
OIL-TK	EU	115-FOT	VOC	30 TAC Chapter 115, Storage of VOCs	§ 115.111(a)(1)	Except as provided in §115.118 of this title (relating to Recordkeeping Requirements), any volatile organic compound (VOC) with a true vapor pressure less than 1.5 pounds per square inch absolute (psia) (10.3 kPa) at storage conditions is	None	§ 115.118(a)(1) § 115.118(a)(6)(A)	None

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
						exempt from the requirements of this division (relating to the Storage of Volatile Organic Compounds).			

Additional Monitoring Requirements

Compliance Assurance Monitoring Summary 30

Periodic Monitoring Summary 31

CAM Summary

Unit/Group/Process Information	
ID No.: E-GT	
Control Device ID No.: SCR	Control Device Type: Selective Catalytic Reduction (SCR)
Control Device ID No.: STINJT	Control Device Type: Other Control Device Type
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart GG	SOP Index No.: NG2
Pollutant: NOX	Main Standard: § 60.332(a)(1)
Monitoring Information	
Indicator: Nitrogen Oxides Concentration	
Minimum Frequency: four times per hour	
Averaging Period: one hour	
Deviation Limit: 110.2 ppmv NOX (corrected to 15% oxygen), when firing natural gas. 106.2 ppmv NOX (corrected to 15% oxygen), when firing fuel oil.	
CAM Text: Use a continuous emission monitoring system (CEMS) to measure and record the concentration of nitrogen oxides and either oxygen or carbon dioxide in the exhaust stream of the control device. The CEMS shall be operated in accordance with the monitoring requirements of 40 CFR § 60.13 and the performance specifications of 40 CFR Part 60, Appendix B. NOx Emissions shall be corrected/calculated in units of the underlying applicable emission limitation (grams per horsepower-hour, pounds per MMBtu, pounds per hour).	

Periodic Monitoring Summary

Unit/Group/Process Information	
ID No.: E-HRSG	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Da	SOP Index No.: NG1
Pollutant: PM	Main Standard: § 60.42Da(a)(1)
Monitoring Information	
Indicator: Fuel type	
Minimum Frequency: Annually or at any time an alternate fuel is used	
Averaging Period: n/a	
Deviation Limit: Firing of alternative fuel or failure to keep records of fuel type.	
Periodic Monitoring Text: Record the type of fuel used. If an alternative fuel is fired either alone or in combination it shall be considered a deviation.	

Periodic Monitoring Summary

Unit/Group/Process Information	
ID No.: E-HRSG	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Da	SOP Index No.: NG1
Pollutant: SO_2	Main Standard: § 60.43Da(b)(2)
Monitoring Information	
Indicator: Fuel sulfur content	
Minimum Frequency: every 30-days	
Averaging Period: 30-days	
Deviation Limit: Maximum SO2 emissions = 0.20 lb/MMBtu heat input	
Periodic Monitoring Text: Use the requirements of 40 CFR Part 75, Appendix D Sections 2.3.1.1 and 2.3.1.4 to satisfy the monitoring provisions of 40 CFR 60.48Da, demonstrating compliance with the SO2 limit.	

Permit Shield

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Permit Shield

The Executive Director of the TCEQ has determined that the permit holder is not required to comply with the specific regulation(s) identified for each emission unit, group, or process in this table.

Unit/Group/Process		Regulation	Basis of Determination
ID No.	Group/Inclusive Units		
E-HRSG	N/A	40 CFR Part 63, Subpart DDDDD	Site is not a major HAP source (Boiler MACT)
FP-1	N/A	40 CFR Part 60, Subpart IIII	Diesel fire pump engine constructed prior to applicability date
E-GT	N/A	40 CFR Part 63, Subpart YYYY	Site is not a major HAP source (Turbine MACT)
OIL-TK	N/A	40 CFR Part 60, Subpart Kb	Fuel oil tank storing material with a TVP less than 3.5 kPa
OIL-TK2	N/A	30 TAC Chapter 115, Storage of VOCs	Storage capacity is less than 1,000 gallons.
OIL-TK2	N/A	40 CFR Part 60, Subpart Kb	Fuel oil tank storing material with a TVP less than 3.5 kPa

New Source Review Authorization References

New Source Review Authorization References 36

New Source Review Authorization References by Emission Unit 37

New Source Review Authorization References

The New Source Review authorizations listed in the table below are applicable requirements under 30 TAC Chapter 122 and enforceable under this operating permit.

Prevention of Significant Deterioration (PSD) Permits	
PSD Permit No.: PSDTX839	
Title 30 TAC Chapter 116 Permits, Special Permits, and Other Authorizations (Other Than Permits By Rule, PSD Permits, or NA Permits) for the Application Area	
Authorization No.: 25384	
Permits By Rule (30 TAC Chapter 106) for the Application Area	
Number: 106.227	Version No./Date: 09/04/2000
Number: 106.263	Version No./Date: 11/01/2001
Number: 106.371	Version No./Date: 09/04/2000
Number: 106.373	Version No./Date: 09/04/2000
Number: 106.454	Version No./Date: 11/01/2001
Number: 106.472	Version No./Date: 09/04/2000
Number: 106.511	Version No./Date: 09/04/2000

New Source Review Authorization References by Emissions Unit

The following is a list of New Source Review (NSR) authorizations for emission units listed elsewhere in this operating permit. The NSR authorizations are applicable requirements under 30 TAC Chapter 122 and enforceable under this operating permit.

Unit/Group/Process ID No.	Emission Unit Name/Description	New Source Review Authorization
E-GT	250 MW GAS TURBINE	25384, PSDTX839
E-HRSG	375 MMBTU/HR HRSG	25384, PSDTX839
FO-LOAD1	FUEL LOADING UNLOADING POINT	106.472/09/04/2000
FP-1	182-HP DIESEL FIRE WATER PUMP ENGINE	25384, PSDTX839
OIL-TK2	FUEL OIL TANK 2	25384, PSDTX839
OIL-TK	FUEL OIL TANK	25384, PSDTX839

Appendix A

Acronym List.....39

Acronym List

The following abbreviations or acronyms may be used in this permit:

ACFM ..... actual cubic feet per minute
AMOC ..... alternate means of control
ARP ..... Acid Rain Program
ASTM ..... American Society of Testing and Materials
B/PA ..... Beaumont/Port Arthur (nonattainment area)
CAM ..... Compliance Assurance Monitoring
CD ..... control device
COMS ..... continuous opacity monitoring system
CVS ..... closed-vent system
D/FW ..... Dallas/Fort Worth (nonattainment area)
DR ..... Designated Representative
EIP ..... El Paso (nonattainment area)
EP ..... emission point
EPA ..... U.S. Environmental Protection Agency
EU ..... emission unit
FCAA Amendments ..... Federal Clean Air Act Amendments
FOP ..... federal operating permit
GF ..... grandfathered
gr/100 scf ..... grains per 100 standard cubic feet
HAP ..... hazardous air pollutant
H/G/B ..... Houston/Galveston/Brazoria (nonattainment area)
H_2S ..... hydrogen sulfide
ID No. ..... identification number
lb/hr ..... pound(s) per hour
MMBtu/hr ..... Million British thermal units per hour
MRRT ..... monitoring, recordkeeping, reporting, and testing
NA ..... nonattainment
N/A ..... not applicable
NADB ..... National Allowance Data Base
NO_x ..... nitrogen oxides
NSPS ..... New Source Performance Standard (40 CFR Part 60)
NSR ..... New Source Review
ORIS ..... Office of Regulatory Information Systems
Pb ..... lead
PBR ..... Permit By Rule
PM ..... particulate matter
ppmv ..... parts per million by volume
PSD ..... prevention of significant deterioration
RO ..... Responsible Official
SO_2 ..... sulfur dioxide
TCEQ ..... Texas Commission on Environmental Quality
TSP ..... total suspended particulate
TVP ..... true vapor pressure
U.S.C. ..... United States Code
VOC ..... volatile organic compound

Attachment G

BEPC's Application Submitted to Obtain TCEQ Permit No. 25384, PSDTX839

Espey, Huston & Associates, Inc.
Engineering & Environmental Consultants

Document No. 940312
EH&A Job No. 15495

APPLICATION FOR A TNRCC/PSD AIR QUALITY CONSTRUCTION PERMIT FOR THE CLEBURNE COGENERATION PROJECT CLEBURNE, TEXAS

Prepared for:

Tenaska Power Partners, L.P.
1044 N. 115 Street, Suite 400
Omaha, Nebraska 68154-4446

Prepared by:

Espey, Huston & Associates, Inc.
P.O. Box 519
Austin, Texas 78767

STATE OF TEXAS
RUBEN I. VELASQUEZ
69126
REGISTERED PROFESSIONAL ENGINEER

Ruben I. Velasquez
6-20-94

June 1994

P.O. Box 519 • Austin, Texas 78767-0519
206 Wild Basin Road, Suite 300 (78746-3343)
(512) 327-6840 TEL • (512) 327-2453 FAX

TENASKA POWER PARTNERS, L.P.

1044 N. 115 Street, Suite 400
Omaha, Nebraska 68154-4446

Telephone: (402) 691-9500
Fax: (402) 691-9526

June 17, 1994

Mr. Jeff Saitas, P.E.
Director, New Source Review Program
Office of Air Quality
Texas Natural Resource Conservation Commission
P.O. Box 13087
Austin, Texas 78711-3087

RE: Texas Natural Resource Conservation Commission (TNRCC) and Prevention of Significant Deterioration (PSD) Permit Application for the Tenaska Cleburne Cogeneration Project, Cleburne, Johnson County, Texas

Dear Mr. Saitas:

Enclosed please find one copy of our TNRCC/PSD application for a permit to construct our Cleburne Cogeneration Project prepared by Espey, Huston & Associates, Inc. (EH&A) on behalf of Tenaska Power Partners, L.P. The project will be located north of the city of Cleburne, Texas and will consist of two cogeneration systems which will produce a combined nominal net plant output of 500 MWe of electricity. The project will utilize the Best Available Control Technology (BACT) in controlling emissions and will comply with all the rules and regulations of both the TNRCC and the EPA. An air quality analysis of the project will be submitted after a preliminary determination has been made by the TNRCC air quality staff that the emissions calculations and controls proposed as BACT are acceptable. A new business entity (Tenaska IV Texas Partners, Ltd.) in the process of being formed to own and operate the new facility as noted on the enclosed TNRCC Air Quality PI-1, General Application Form.

Thank you for your consideration of this request. A check for the permit fee of $75,000 is enclosed. Please note that Tenaska requires approval of the TNRCC air quality permit by December 1994 in order to meet financial and contractual obligations to the project.

TENASKA, INC., Managing General Partner
EMPECO II, INC., General Partner
(a subsidiary of Continental Energy Services, Inc.)

TENASKA

Therefore, your expeditious review of this application would be very much appreciated. If you should have any questions or comments regarding this application, please contact Mr. Ruben Velasquez of EH&A at (512) 329-8342, extension 9578 or me at (402) 691-9500.

Very truly yours,

Tenaska Power Partners, L.P.
By: Tenaska, Inc., Managing Partner

By:
Michael C. Lebens
Vice President

MCL:cw

Enclosure

cc: Ms. Jole Luehrs, U.S. Environmental Protection Agency, Region 6 Office
Mr. Melvin Lewis, TNRCC Region 4 Office
Mr. Ruben I. Velasquez, P.E., Espey, Huston & Associates, Inc.

9404112A.ECW

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Espey, Huston & Associates, Inc.

SECTION 1.0

INTRODUCTION AND GENERAL DESCRIPTION

1.0 INTRODUCTION AND GENERAL DESCRIPTION

Tenaska IV Texas Partners, Ltd. (Tenaska) is proposing to construct a cogeneration project, hereafter referred to as "project", in Cleburne, Johnson County, Texas. The plant site will be located in the Cleburne Industrial Park north of the intersection of Texas Highways 171 and 174. The project will consist of two gas turbine electric generating units, each of which exhausts into a duct burner-fired heat recovery steam generator (HRSG). These units will be primarily natural gas-fired with diesel fuel backup for the gas turbines. In addition, two steam turbine generators will be constructed for added capacity. The plant will produce a combined nominal net output of 500 MWe of electricity. The electric power generated by the proposed cogeneration project will be sold to an electric utility company. The steam produced will be sold to an adjacent industrial facility. An auxiliary boiler will also be installed to serve as a backup source for steam production for the adjacent industrial facility. The auxiliary boiler will also be primarily natural gas-fired with diesel fuel backup.

The project will require that Tenaska obtain an air quality permit from the Texas Natural Resource Conservation Commission (TNRCC) and a Federal Prevention of Significant Deterioration (PSD) permit prior to commencement of construction. Tenaska will make use of the Best Available Control Technology (BACT) in controlling emissions from this project. The results of atmospheric dispersion modeling of air contaminant emissions, which will be submitted in a separate document, will demonstrate that emissions from the proposed project will not cause or contribute to an exceedance of Federal ambient air quality standards, state property-line standards or screening levels.

This document constitutes Tenaska's application to the TNRCC for a permit to construct the proposed project. As the TNRCC is delegated authority for the review and issuance of PSD permits, the required information for PSD review is incorporated into this application. The sections that follow contain the descriptions, data, analyses, drawings, and other information required by the TNRCC to complete its review of this application. The section numbers are related to the sections referenced in the TNRCC Form PI-1, General Application (see Section 2.0) followed by additional information required to address PSD requirements.

This application has been prepared based on information and guidance from the TNRCC at a pre-application meeting with the TNRCC on 23 March 1994 and a pre-modeling meeting with the TNRCC on 27 April 1994. A complete modeling analysis will be provided at a later date as a separate document submitted in support of this application. This modeling will be based on a preliminary review by the TNRCC of the protocol to be used for modeling and the project's BACT and emission rate calculations.

The project will be built in two phases. Construction of the first gas turbine/HRSG unit will commence upon issuance of the permit. Construction of the second gas turbine/HRSG will commence after a power purchase agreement is signed for the additional power produced. It is important to note that Tenaska requires approval of the TNRCC air quality permit by November 1994 in order to meet financial and contractual obligations. Therefore, an expeditious review of this application will be appreciated.

Espey, Huston & Associates, Inc.

SECTION 2.0

FORM PI-1

FORM PI-1, GENERAL APPLICATION -- AIR QUALITY PERMIT

TNRCC

A PERMIT TO CONSTRUCT MUST BE APPROVED BEFORE ANY ACTUAL WORK IS BEGUN ON THE FACILITY. This is not a stand alone document. Please refer to the "Form PI-1, Permit Application Instructions" manual (Instructions) for specific details to complete this application. Please print or type all information. All information requested herein must be completed and submitted before public notification procedures may be authorized. Please contact the CORE Section of the New Source Review Program with any questions at 512/908-1000 (FAX No. 512/908-1300). Written inquiries may be addressed to: Texas Natural Resource Conservation Commission, Office of Air Quality, New Source Review Program, P.O. Box 13087, Austin TX 78711-3087.

V E R Y I M P O R T A N T !

- Is CONFIDENTIAL information being submitted with this application? [ ]-YES [X]-NO
  If YES, is each "confidential" page so marked in big red letters? [ ]-YES [ ]-NO
- Has a CORE checklist been attached to this application? ..... [X]-YES [ ]-NO
- Is this application in response to, or related in any way to, a Notice of Violation at this location? [ ]-YES [X]-NO. If YES, date of Notice of Violation: _____
  Also, if YES, pursuant to Rule: _____

Please furnish the following information pertaining to this facility SITE:

1. Please estimate the net number of new jobs which will be created in the community as a result of the operation of the facility authorized by this application: 25
2. Name of elected State Senator: Jane Nelson
3. Name of elected State Representative: Bernard Ericson

Please furnish the following information pertaining to Compliance History:
Submit a 5-year Compliance History in accordance with Regulation VI, Rule 116.120-116.126 for all facilities classified in Sections V.C and V.D of Form PI-1 below.

I. TYPE OF APPLICATION: [X]-CONSTRUCTION PERMIT [ ]-AMENDMENT, Permit No. _____

A. PERMIT ISSUED TO: Tenaska Power Partners, L.P.
(Entity legally responsible for permit; i.e., Owner or Operator of the facility)
Permittee's Texas State Comptroller's Tax ID No.: not yet received
Permittee's address (Person, Title, Address): 1044 N. 115 Street, Suite 400, Omaha, Nebraska 68154-4446
Telephone: (402) 691-9500 FAX: (402) 691-9530
Permittee's Technical Contact (Person, Title, Address): Michael C. Lebens, Vice President of Engineering, Tenaska Power Partners, L.P., 1044 N. 115 Street, Suite 400, Omaha, Nebraska 68154-4446 Telephone: (402) 691-9500 FAX: (402) 691-9530

B. OWNER OF FACILITY: Tenaska IV Texas Partners, LTD.
(If different from permittee; include names of proprietor/general partner(s) if applicable)
Owner's Texas State Comptroller's Tax ID No.: not yet received
Owner's address (Person, Title, Address): 1044 N. 115 Street, Suite 400, Omaha, Nebraska 68154-4446

C. Principal Company Product or Business: Cogeneration of steam and electricity
Plant SIC Code: 4911

I. FACILITY PHYSICAL LOCATION:

A. Name of plant or site: Tenaska Cleburne Cogeneration Project
B. Street Address: Cleburne Industrial Park north of the intersection of Texas Highways 171 and 174
C. Nearest City: Cleburne County: Johnson Site Zip Code: 76031
D. Latitude: 32 ° 23 ' 57 "N Longitude: 97 ° 24 ' 29 "W (must be to nearest second)
E. Plant Site TNRCC Air Quality Account Number: ____-_____-__

III. FACILITY TYPE AND OPERATING SCHEDULE:

A. Name of facility to be permitted: Tenaska Cleburne Cogeneration Project
B. Facility Type (Check One): [X] Permanent, [ ] Portable.
C. Facility Operating Schedule: (24) Hours/day; (7) Days/week; (52) Weeks/year
(___) Seasonal - explain: _____
D. Start Dates (Proposed/Actual): Construction: 1 / 1 / 95 (P/A) P
Operation: 1 / 1 / 97 (P/A) P

IV. FACILITY CLASSIFICATION (Check only one block):

A. [X] New Permitted Facility - New grass roots facility at this location.
B. [ ] New Permitted Facility - Modification of existing non-permitted Facility.
C. [ ] Amendment to Permitted Facility. Permit No(s). _____
D. [ ] Change in Location of Permitted Facility. Permit No(s). _____
Location of Present Facility: _____

V. COMPLIANCE HISTORY (See attached Supplemental Information Sheet):

A. [ ] Exemption claimed under Rule 116.121, or
B. [ ] Existing Site => 5 years old. TNRCC will compile Compliance History, or
C. [X] New Site (This is a new grassroots site with no operating history), or
D. [ ] Existing Site < 5 years old.

If "C" or "D", does applicant have similar facilities in Texas? [X]-YES [ ]-NO.
1. If YES, list TNRCC Air Quality Account No.(s): 1A-0045-F (Tenaska Affiliate) Tenaska III Texas Partners
2. If NO, attached one of the following:
   a. [ ] Compliance History for similar sites in other States. If none, then:
   b. [ ] Compliance History as required by Regulation VI, Rule 116.122(b).

(Over)

VI. **SUBMIT THE FOLLOWING GENERAL INFORMATION:**

A. Submit a current area map as specified in the Instructions.
Are any schools located within 3000 feet of this facility? [ ]-YES [X]-NO.

B. Submit a plot plan of the plant property as specified in the Instructions.

C. Submit emission data, including fugitive emissions and stack parameters, on Table 1(a). Attach emission calculations and information showing how emissions were determined. See Instructions for further details.

D. Submit an analysis of Best Available Control Technology, including the estimated installed capital and operating costs for all abatement equipment associated with the facility. See Instructions for further details.

V E R Y I M P O R T A N T !

E. **Franchise Tax. Submit a copy of a Certificate of Good Standing from the State Comptroller's Office with each application if the permit is to be issued to a corporation. See Instructions if you are not a corporation or for further information.**

F. **Permit Fee. Enclose required fee, fee certification and estimated capital cost (Table 30); or furnish explanation why fee is not required. (See Regulation VI Rule 116.141.)** A check for $75,000 is enclosed as the capital cost of the project will exceed $15,000,000.

VII. **SUBMIT (A) PROCESS FLOW DIAGRAM, (B) PROCESS DESCRIPTION AND (C) MATERIAL BALANCE AS SPECIFIED IN THE INSTRUCTIONS** (see Instructions concerning submittal of confidential information

VIII. **GENERAL APPLICATION REQUIREMENTS:**
Submit itemized information and/or analysis that will demonstrate that all general application requirements as specified in Rule 116.111 of TNRCC Regulation VI are met. **Each requirement in Rule 116.111 must be addressed in this application.** See Instructions for further details. Atmospheric dispersion modeling may be required as part of the air quality impact analysis per Rule 116.111(9).

Is this facility a MAJOR SOURCE/MODIFICATION with regard to one of the following:
1. §116.111(7) - Nonattainment ..... [ ]-YES [X]-NO
2. §116.111(8) - Prevention of Significant Deterioration [X]-YES [ ]-NO.

IX. **APPEAL PROCESS:**
Commission Rule 116.114(a)(3) should be consulted for the procedure to be used to appeal the failure of the agency to process an application within the prescribed time limits.

X. A copy of this application and all attachments must be sent by the applicant to the EPA Region 6 office in Dallas if PSD or Nonattainment Review is applicable in any form, the appropriate TNRCC Regional Office and to any local air pollution control program having jurisdiction. Copies of the application were sent to:

EPA Region 6 Office in Dallas ..... : [X]-YES [ ]-Not applicable.
TNRCC Regional Office (city) sent to: Region 4 - Arlington
Copies sent to these local programs: 1. _____
[X]-NOT APPLICABLE. 2. _____

XI. **§116.110(d). PE Seal.** Is the estimated capital cost of the project for which application is made greater than $2 million dollars? [X]-YES [ ]-NO

If YES, application must be submitted under seal of a Texas registered Professional Engineer, unless exemption is claimed pursuant to the Texas Engineering Practice Act.
[ ] - Exemption is claimed pursuant to Section _____ of the TEPA.

XII. I, Michael C Legens - Vice President of Tenaska Inc, Managing Partner of Tenaska Power Partners, L.
(Name - Please print or type) (Title: Owner, Plant Manager, President, Vice-President, Environmental Director, etc.)
state that I have knowledge of the facts herein set forth and that the same are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Health & Safety Code (THSC), Chapter 382, Texas Clean Air Act, as amended, or any of the air quality Rules and Regulations of the Texas Natural Resource Conservation Commission or any local governmental ordinance or resolution enacted pursuant to the Texas Clean Air Act. I further state that I have read and understand Section 382.091, THSC, which defines CRIMINAL OFFENSES for certain violations, including intentionally or knowingly making or causing to be made false material statements or representations in this application, and Section 382.092, THSC, pertaining to CRIMINAL PENALTIES.

DATE 6/16/94 SIGNATURE _____

NOTE - ORIGINAL SIGNATURE IN INK IS REQUIRED.

Michael C Legens

NOTE TO APPLICANT: PLEASE MARK ... labeled "Comments & Discussion" to further explain your action.

TEXAS NATURAL RESOURCE CONSERVATION COMMISSION
PERMITS DIVISION - CORE SECTION
AIR QUALITY PERMIT APPLICATION
ADMINISTRATIVE COMPLETENESS CHECKLIST

TNRCC

CAWPHIOCOMPLETENESSCHECKLIST 803 Rev 08/01/93

COMPANY Tenaska Power Partners, L.P. PROJ No.: _____ PROJ TYPE: _____ CORE ENGR: _____ RECORD No.: _____
REGION 4 COUNTY Johnson Tech. Contact: Michael C. Lebens, VP of Engineering Phone: (402)691-9500
DATE RECD by CORE: _____ Comments _____ DATE ADMIN COMP: _____
DATE RECD by TECH. ENGR: _____ Comments _____ TECH. ENGR: _____ TECHNICAL SECT.: _____

<------ TNRCC use only ------->

PI-1 REF	REQUIRED INFORMATION	Applicant use	DATE ADMIN COMPLETE	NOT COMPLETE	NOTHING SUBMITTED	COMMENTS & DISCUSSION
	CONFIDENTIAL Information?(1)	X				[ ]YES [X]NO
	CONFIDENTIAL pages marked?	N/A				[ ]YES [ ]NO
	CORE Checklist attached	X *				[X]YES [ ]NO
	NOV related notification	N/A				[ ]YES [X]NO
	Net number of new jobs created	X				
	Name of elected State Senator	X				
	Name of elected St. Representative	X				
I.	Type of Application	X *				[X]PERMIT [ ]AMENDMENT
	A. Permittee Name, Tax ID & Addr.	X				
	Technical Contact (addr,phone)	X				
	B. Owner Name, Tax ID & Addr.	X				
	C. Product/Business & SIC Code	X *				
II.	A. Plant/Site Name	X				
	B. Address of Facility	X				
	C. Nearest City, County and Zip	X *				
	D. Latitude and Longitude	X				
	E. TNRCC Air Quality Acct. No.	N/A *				This is a grass roots facility.
III.	A. Name of Facility	X				
	B. Facility Type	X				[X]PERMANENT [ ]PORTABLE
	C. Operating Schedule	X				
	D. Start Dates	X *				CONST DATE 1-1-95 OPER DATE 1-1-97
IV.	A. New Permit Unit - grass roots	X				New grass roots facility at this location.
	B. New Permit Unit - non-permitted					Modification of exist. non-permitted facility.
	C. Amendment to permitted facility					[ ]Present Permit No. _____
	D. Change in Location					[ ]Present Permit No. _____
V.	A. Compliance History - Exempt					[ ]YES [X]NO
	B. Comp. Hist. - site => 5 yr old					[ ]YES [X]NO
	C. Comp. Hist. - new site	X				[X]YES [ ]NO
	D. Comp. Hist. - site < 5 yr old					[ ]YES [X]NO
VI.	A.1 Area Map	X				
	School Within 3,000 feet?	X				[ ]YES [X]NO
	A.2 Plot Plan	X				
	B. Emission Data & Table 1(a)	X				
	C. BACT Analysis	X				
	D. Franchise Tax Certificate	N/A *				[X]N/A [ ]Certificate good thru __/__/__
	E. Permit Fee Required?	X				[X]YES [ ]NO
	Fee Cert. & Table 30	N/A				The capital cost of the project will
VII.	A. Process Flow Diagram	X				exceed $15,000,000.
	B. Process Description	X				
	C. Material Balance	X				
VIII.	116.111(1) TNRCC Rules & Regs	X				
	116.111(2) Emissions Measurement	X				
	116.111(3) BACT Analysis	X				
	116.111(4) NSPS	X				
	116.111(5) NESHAPS	X				
	116.111(6) Facility Performance	X				
	116.111(7) Non-Attainment review	X				MAJOR SOURCE/MODIFICATION? [ ]YES [X]NO
	116.111(8) PSD review	X				MAJOR SOURCE/MODIFICATION? [X]YES [ ]NO
	116.111(9) Impacts/Modeling					will be submitted at a later date
X.	Copy to EPA Region 6 office	X *				[X]YES [ ]N/A
	Copy to TNRCC Regional Office	X *				[X]YES City - Arlington
	Copy to Local Program(s)	N/A *				[ ]YES [X]N/A
XI.	Application "sealed" by P.E.?	X				[X]YES [ ]NO
XII.	Authorizing Signature/Date	X				

* *These items will not result in the application being considered administratively deficient; however, they MUST be submitted prior to final action or approval of the application.*

(1) *CONFIDENTIAL information MUST be clearly marked on each page and separated from non-confidential information. The application must include in the non-confidential files a topic outline describing the confidential information. To be considered confidential, each page must be marked "CONFIDENTIAL" at the time of submittal.*

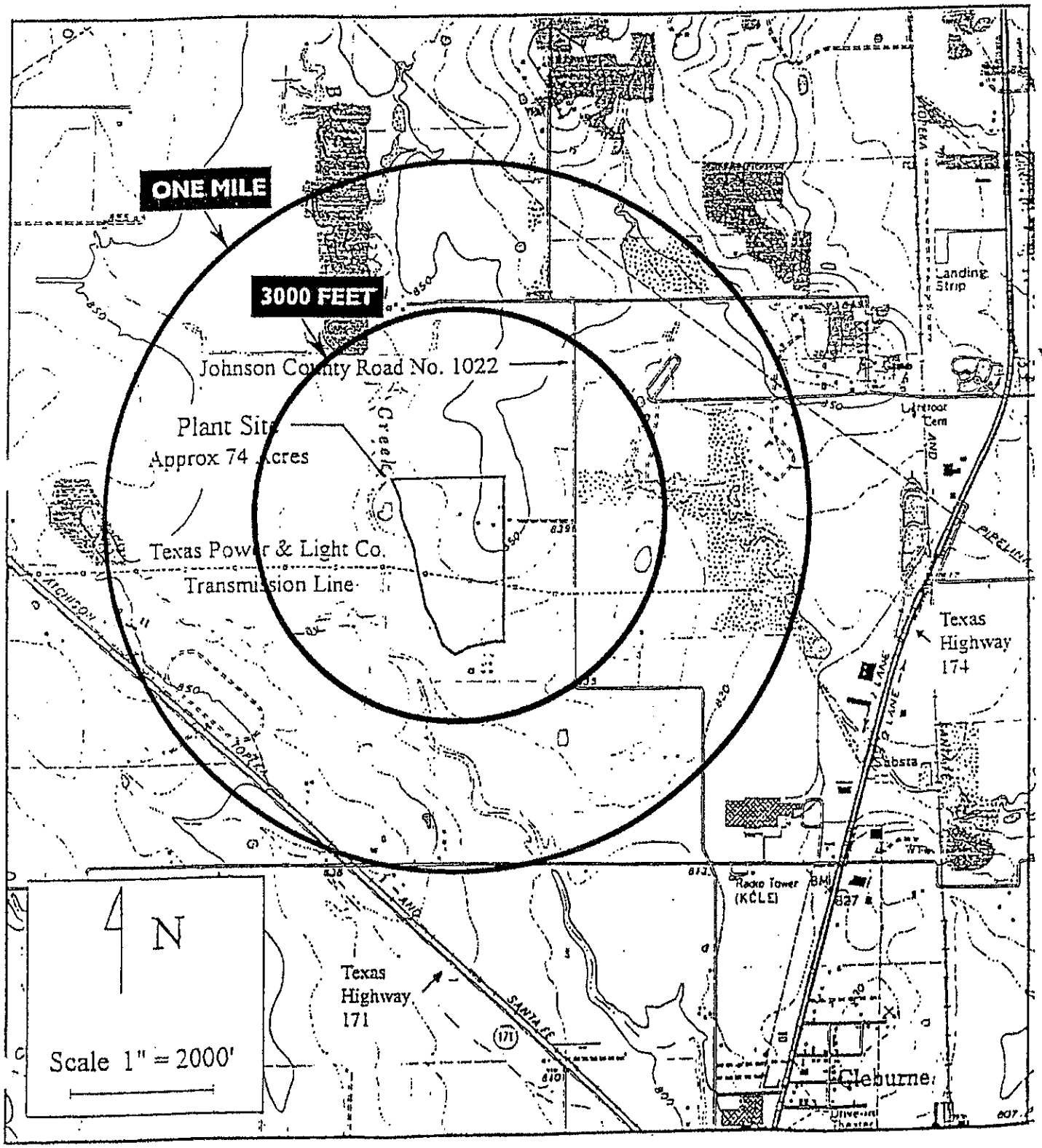
Espey, Huston & Associates, Inc.

ITEM VI.A

AREA MAP

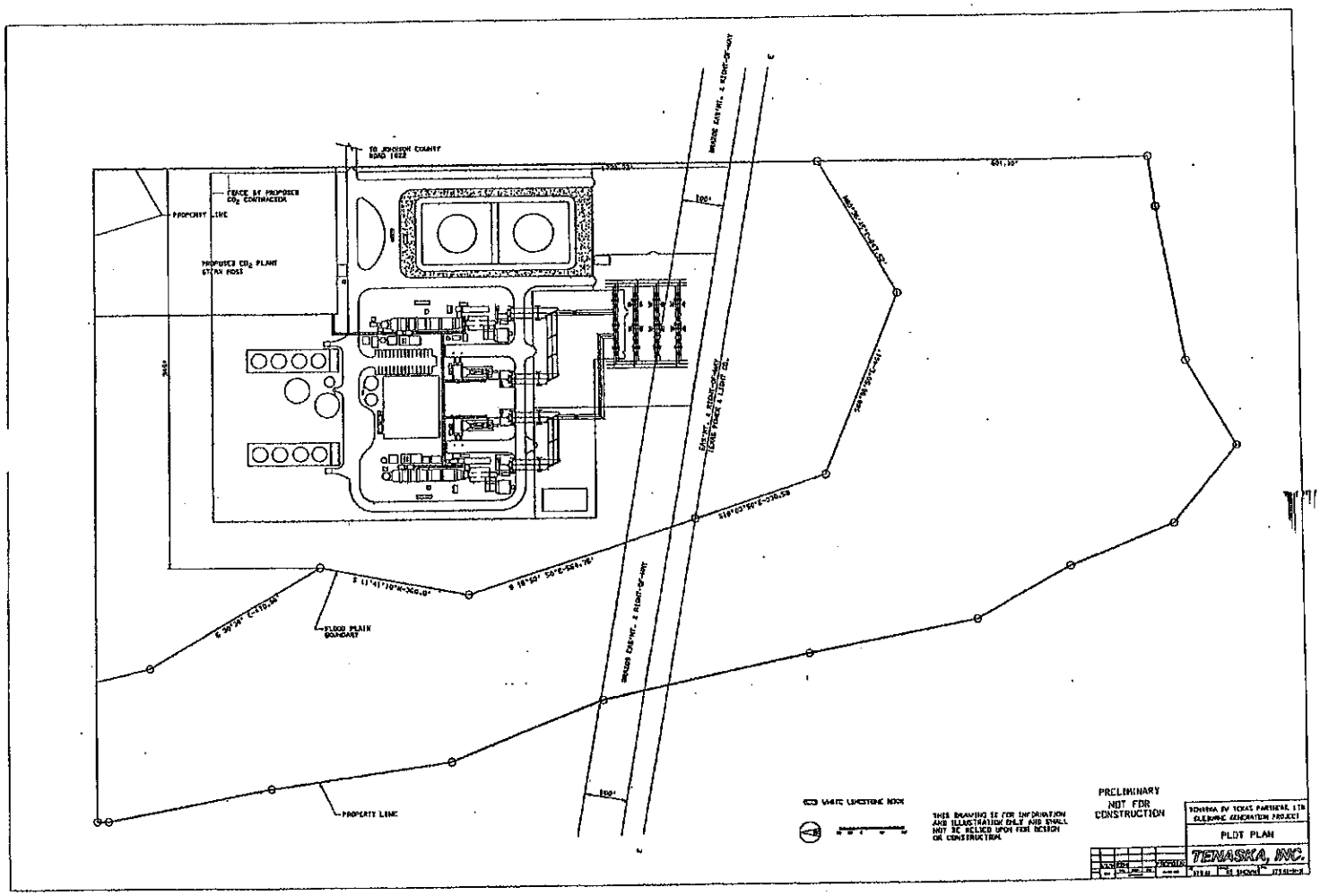
15495\940312

Tenaska Brazos Cogeneration Project
Cleburne, Johnson County, Texas
Plant Location



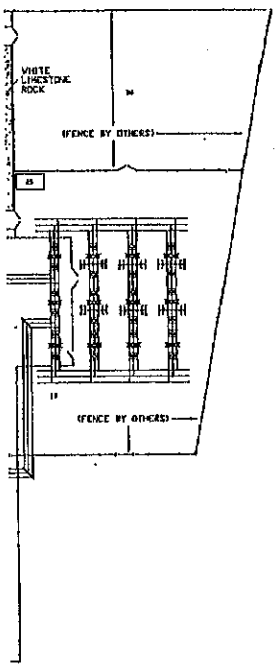
Harry, Hunton & Associates, Inc.

ITEM VI-B
PLOT PLAN


TO JOHNSON COUNTY ROAD 1022
FENCE BY PROPOSER CO_2 CONTRACTOR
PROPERTY LINE
PROPOSED CO_2 PLANT STRAW POST
FLOOD PLAIN BOUNDARY
PROPERTY LINE
100'
PRELIMINARY
NOT FOR CONSTRUCTION
THIS DRAWING IS FOR INFORMATION AND ILLUSTRATION ONLY AND SHALL NOT BE RELIED UPON FOR DESIGN OR CONSTRUCTION
TENASKA BY TEXAS PARTNERS, LTD
ELECTRIC GENERATION PROJECT
PLOT PLAN
TENASKA, INC.

LEGEND

1. NATURAL GAS SCRUBBER
2. BOILER DRAIN SUMP
3. WATER METER HOUSE
4. COOLING TOWER WATER TREATMENT BUILDING
5. COOLING TOWER
6. CIRCULATING WATER PUMPS
7. STEAM TURBINE
8. LIQUID FUEL PACKAGE
9. PARKING
10. GENERATOR
11. DUCT BURNER MANAGMENT SKID
12. BUILDING FIRE CONTROL & SWITCH GEAR, WATER TREATMENT, OFFICE, MAINTENANCE.
13. GENERATOR STEPUP TRANSFORMER
14. MECHANICAL AND ELECTRICAL CONTROL PACKAGES
15. BFW PUMPS
16. CONDENSATE RETURN TANK
17. BRAZOS SWITCHYARD
18. TENASKA SWITCHYARD
19. AIR INLET
20. ATOMIZING AIR SKID
21. STARTING MOTOR
22. COMBUSTION TURBINE
23. STORM WATER RETENTION POND
24. AMMONIA BLOWER
25. BRAZOS RELAY BUILDING
26. CONDENSER TUBE REMOVAL
27. AMMONIA TANK
28. BLOWDOWN TANK
29. HEAT RECOVERY STEAM GENERATOR
30. EVAP COOLER SUMP
31. WATER PUMP HOUSE
32. CITY WATER TANK
33. NEUTRALIZATION TANK
34. DEMINERALIZED WATER STORAGE TANK
35. CONDENSATE PUMPS
36. ACID TANK
37. OIL-WATER SEPARATOR
38. CAUSTIC TANK
39. AUXILIARY COOLING WATER PUMPS
40. COOLING TOWER MAKEUP STORAGE TANK
41. CO2 FIRE PROTECTION SKID
42. BARGE DOCK
43. OIL STORAGE TANK
44. FUEL OIL UNLOADING AND TRANSFER PUMPS
45. H.R.S.G. STACK
46. UNIT AUX. TRANSFORMER
47. NATURAL GAS CUSTODY FILTERS, REGULATION AND METER
48. WASTE WATER SUMP
49. GENERATOR
50. FIRE HALL
51. PIPE RACK
52. CONTINUOUS EMISSION MONITOR BUILDING
53. NOT USED
54. BOILER CHEMICAL FEED BUILDING (ALSO BFW'S)
55. COMPRESSOR ON-LINE OFF-LINE WATER WASH SKID
56. BRAZOS DISTRIBUTION SUBSTATION
57. CEDEN AUX BOILER
58. AUX BOILER FD FAN
59. FUEL GAS PREHEATER
60. REFUSE BOILER
61. VACUUM PUMP HOUSE



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NOT FOR
NSTRUCTION

TENASKA IV TEXAS PARTNERS, LTD.
ELEMORNE GENERATION PROJECT

PLOT PLAN

TENASKA, INC.

PROPOSAL

179-41 | AS SHOWN | 179-41-M-10

Espey, Huston & Associates, Inc.

ITEM VI.C

TNRCC TABLE 1(a)s - EMISSIONS SOURCES

PERMIT NO.
ACCOUNT ID NO.

PAGE 1 OF 4
DATE JUNE 1994

TABLE 1(a)
EMISSION SOURCES

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS									
EMISSION POINT [1]		CHEMICAL COMPOSITION OF TOTAL STREAM		AIR CONTAMINANT EMISSION RATE		UTM COORDINATES OF EMISSION PT. [6]			STACK SOURCES [7]					AREA SOURCES(8)	
									HEIGHT ABOVE GROUND	HEIGHT ABOVE STRUCT.	EXIT DATA				
NUMBER	NAME	COMPONENT OR AIR CONTAMINANT NAME [2]	CONC.(%v) [3]	# / HR [4]	TONS/YR [5]	ZONE	EAST (meters)	NORTH (meters)	(ft)	(ft)	DIA. (ft)	VEL. (fps)	TEMP. (°F)	LENGTH (ft)	WIDTH (ft)
W-GT/HRSG	West GT/HRSG Stack	NO_x		117.1	278.2	14	649615	3585576	110		18.0	47.3	180		
		SO_2		94.9	80.1										
		CO		311.0	495.4										
		VOC		30.0	80.8										
		Particulate		66.9	78.77										
		PM_{10}		66.0	74.8										
		Ammonia		32.5	127.4										

GROUND ELEVATION OF FACILITY ABOVE MEAN SEA LEVEL – 840 FEET.
TACB STANDARD CONDITIONS ARE 68°F AND 14.7 PSIA [RULE 131.01.00.001(55)]
General Instructions:

1. Identify each emission point with a unique number for this plant site, consistent with emission point identification used on plot plan, previous permits and Emissions Inventory Questionaire. Limit emission point number to 5 character spaces. For each emission point use as many lines as necessary to list contaminant data. Typical emission point names are: heater, vent, boiler, tank, reactor, separator, baghouse, fugitive, etc. Abbreviations are OK.
2. Typical component names are: air, H_2O, nitrogen, oxygen, CO_2, NO_x, SO_2, hexane, particulate matter (PM), etc. Abbreviations are OK.
3. Concentration data is required for all gaseous components. Show concentration in volume percent of total gas stream.
4. Pounds per hour (#/HR) is maximum emission rate expected by applicant.
5. Tons per year (T/Y) is annual maximum emission rate expected by applicant, which takes into account process operating schedule.
6. As minimum applicant must furnish a facility plot plan drawn to scale showing a plant benchmark, latitude and longitude correct to the nearest second for the benchmark, and all emission points dimensioned with respect to the benchmark as required by General Application, Form PI-1. This information is essential for calculation of emission point UTM coordinates. Please show emission point UTM coordinates if known.
7. Supply additional information as follows if appropriate:
   (a) Stack exit configuration other than a round vertical stack. Show length and width for a rectangular stack. Indicate if horizontal discharge with a note.
   (b) Stack's height above supporting or adjacent structures if structure is within 3 "stack heights above ground" of stack.
   (c) If emission point is a flare, show flare data on Table 8.
8. Normally used for fugitive sources. Show dimensions of a minimum size rectangle which will "enclose" all fugitive sources included in this emission point number.

PERMIT NO.
ACCOUNT ID NO.

PAGE 2 OF 4
DATE JUNE 1994

TABLE 1(a)
EMISSION SOURCES

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS									
EMISSION POINT [1]		CHEMICAL COMPOSITION OF TOTAL STREAM		AIR CONTAMINANT EMISSION RATE		UTM COORDINATES OF EMISSION PT. [6]			STACK SOURCES [7]					AREA SOURCES(8)	
									HEIGHT ABOVE GROUND	HEIGHT ABOVE STRUCT.	EXIT DATA				
NUMBER	NAME	COMPONENT OR AIR CONTAMINANT NAME [2]	CONC.(%v) [3]	# / HR [4]	TONS/YR [5]	ZONE	EAST (meters)	NORTH (meters)	(ft)	(ft)	DIA. (ft)	VEL. (fps)	TEMP. (°F)	LENGTH (ft)	WIDTH (ft)
E-GT/HRSG	East GT/HRSG Stack	NO_x		117.1	276.2	14	649726	3585576	110		16.0	47.3	160		
		SO_2		94.9	80.1										
		CO		311.0	495.4										
		VOC		30.0	80.8										
		Particulate		68.9	78.77										
		PM_{10}		66.0	74.8										
		Ammonia		32.5	127.4										

GROUND ELEVATION OF FACILITY ABOVE MEAN SEA LEVEL – 840 FEET.
TACB STANDARD CONDITIONS ARE 68°F AND 14.7 PSIA [RULE 131.01.00.001(55)]
General Instructions:

1. Identify each emission point with a unique number for this plant site, consistent with emission point identification used on plot plan, previous permits and Emissions Inventory Questionaire. Limit emission point number to 5 character spaces. For each emission point use as many lines as necessary to list contaminant data. Typical emission point names are: heater, vent, boiler, tank, reactor, separator, baghouse, fugitive, etc. Abbreviations are OK.
2. Typical component names are: air, H_2O, nitrogen, oxygen, CO_2, NO_x, SO_2, hexane, particulate matter (PM), etc. Abbreviations are OK.
3. Concentration data is required for all gaseous components. Show concentration in volume percent of total gas stream.
4. Pounds per hour (#/HR) is maximum emission rate expected by applicant.
5. Tons per year (T/Y) is annual maximum emission rate expected by applicant, which takes into account process operating schedule.
6. As minimum applicant must furnish a facility plot plan drawn to scale showing a plant benchmark, latitide and longitude correct to the nearest second for the benchmark, and all emission points dimensioned with respect to the benchmark as required by General Application, Form PI-1. This information is essential for calculation of emission point UTM coordinates. Please show emission point UTM coordinates if known.
7. Supply additional information as follows if appropriate:
   (a) Stack exit configuration other than a round vertical stack. Show length and width for a rectangular stack. Indicate if horizontal discharge with a note.
   (b) Stack's height above supporting or adjacent structures if structure is within 3 "stack heights above ground" of stack.
   (c) If emission point is a flare, show flare data on Table 8.
8. Normally used for fugitive sources. Show dimensions of a minimum size rectangle which will "enclose" all fugitive sources included in this emission point number.

PERMIT NO.
ACCOUNT ID NO.

TABLE 1 (a)
EMISSION SOURCES

PAGE 3 OF 4
DATE JUNE 1994

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

EMISSION POINT [1]		AIR CONTAMINANT DATA: CHEMICAL COMPOSITION OF TOTAL STREAM		AIR CONTAMINANT EMISSION RATE		EMISSION POINT DISCHARGE PARAMETERS: UTM COORDINATES OF EMISSION PT. [6]			STACK SOURCES [7]					AREA SOURCES[8]	
									HEIGHT ABOVE GROUND	HEIGHT ABOVE STRUCT.	EXIT DATA				
NUMBER	NAME	COMPONENT OR AIR CONTAMINANT NAME [2]	CONC.(%v) [3]	# / HR [4]	TONS/YR [5]	ZONE	EAST (meters)	NORTH (meters)	(ft)	(ft)	DIA. (ft)	VEL. (fps)	TEMP. (°F)	LENGTH (ft)	WIDTH (ft)
AUXBOILER	Auxiliary Boiler Stack	NO_x		14.9	43.0	14	649726	3585561	110		3.50	76.4	329		
		SO_2		7.6	6.2										
		CO		26.1	122.7										
		VOC		1.5	4.3										
		Particulate		7.4	5.8										
		PM_{10}		7.1	5.7										

GROUND ELEVATION OF FACILITY ABOVE MEAN SEA LEVEL = 840 FEET.
TACB STANDARD CONDITIONS ARE 68°F AND 14.7 PSIA [RULE 131.01.00.001(55)]
General Instructions:

1. Identify each emission point with a unique number for this plant site, consistent with emission point identification used on plot plan, previous permits and Emissions Inventory Questionaire. Limit emission point number to 6 character spaces. For each emission point use as many lines as necessary to list contaminant data. Typical emission point names are: heater, vent, boiler, tank, reactor, separator, baghouse, fugitive, etc. Abbreviations are OK.
2. Typical component names are: air, H_2O, nitrogen, oxygen, CO_2, NO_x, SO_2, hexane, particulate matter (PM), etc. Abbreviations are OK.
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6. As minimum applicant must furnish a facility plot plan drawn to scale showing a plant benchmark, latitude and longitude correct to the nearest second for the benchmark, and all emission points dimensioned with respect to the benchmark as required by General Application, Form PI-1. This information is essential for calculation of emission point UTM coordinates. Please show emission point UTM coordinates if known.
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8. Normally used for fugitive sources. Show dimensions of a minimum size rectangle which will "enclose" all fugitive sources included in this emission point number.

PERMIT NO.
ACCOUNT ID NO.

TABLE 1(a)
EMISSION SOURCES

DATE JUNE, 1994

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

EMISSION POINT [1]		AIR CONTAMINANT DATA: CHEMICAL COMPOSITION OF TOTAL STREAM		AIR CONTAMINANT EMISSION RATE		EMISSION POINT DISCHARGE PARAMETERS: UTM COORDINATES OF EMISSION PT. [6]			STACK SOURCES [7]					AREA SOURCES(8)	
											EXIT DATA				
NUMBER	NAME	COMPONENT OR AIR CONTAMINANT NAME [2]	CONC. (%v) [3]	# / HR [4]	TONS/YR [5]	ZONE	EAST (meters)	NORTH (meters)	HEIGHT ABOVE GROUND (ft)	HEIGHT ABOVE STRUCT. (ft)	DIA (ft)	VEL (fps)	TEMP. (°F)	LENGTH (ft)	WIDTH (ft)
FP-1	Fire Pump*	PM		0.13	0.0012	14									
		SO_x		0.12	0.0011										
		CO		0.41	0.0035										
		NO_x		1.87	0.016										
		VOC		0.15	0.0013										
H2SO4-TK	Sulfuric Acid Tank	Sulfuric Acid		0.0033	1.5×10^{-1}	14	649656	3585579							
CAUSTIC-TK	Caustic Tank	NaOH		nil	nil	14	649648	3585579							
OIL-TK1	Fuel Oil Tank	Fuel Oil		0.62	0.29	14	649792	3585523							
OIL-TK2	Fuel Oil Tank	Fuel Oil		0.62	0.29	14	649792	3585467							
FUG-OIL	Fugitive Emissions	Fuel Oil		0.88	3.85	14									

GROUND ELEVATION OF FACILITY ABOVE MEAN SEA LEVEL – 840 FEET.
TACB STANDARD CONDITIONS ARE 68°F AND 14.7 PSIA [RULE 131.01.00.001(55)]
General Instructions:

* Emissions are from one 20-minute test every week for maintenance.

1. Identify each emission point with a unique number for this plant site, consistent with emission point identification used on plot plan, previous permits and Emissions Inventory Questionaire. Limit emission point number to 6 character spaces. For each emission point use as many lines as necessary to list contaminant data. Typical emission point names are: heater, vent, boiler, tank, reactor, separator, baghouse, fugitive, etc. Abbreviations are OK.
2. Typical component names are: air, H_2O, nitrogen, oxygen, CO_2, NO_x, SO_2, hexane, particulate matter (PM), etc. Abbreviations are OK.
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Espey, Huston & Associates, Inc.

ITEM VI.D

BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

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ITEM VI.D
BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

1.0 INTRODUCTION

The TNRCC regulations require new stationary sources to apply the BACT in the control of each air contaminant that may be emitted from the project. In addition, the PSD regulations require that BACT be applied to each regulated air contaminant that may be emitted in significant amounts from a major stationary source or a modification to a major source as defined by the PSD rules. As shown in Table 1a, Item VI.C of this application, the project will result in PSD significant emissions of carbon monoxide (CO), particulate matter (PM), particulate matter less than 10 microns in diameter (PM_{10}), nitrogen oxides (NO_x), sulfur dioxide (SO_2), and volatile organic compounds (VOC). In addition, the project will also be a source of ammonia emissions due to the type of controls proposed to control NO_x emissions. Therefore, a BACT analysis is required for these air contaminants. Details of this project are provided in Item VII.B of this application. This section presents a demonstration that BACT will be utilized to control emissions from the project.

2.0 BACT APPROACH

The requirement for the use of BACT is intended to ensure that a proposed facility will incorporate control systems that reflect the latest techniques used in a particular industry, allow for future growth in the vicinity of the proposed facility, and do not result in an exceedance of National Ambient Air Quality Standards. The TNRCC guidance on the approach to BACT is a three tiered approach to the determination of what is BACT. The first tier reflects the type of control which has been determined to be BACT for a similar air contaminant source. The second tier is the control which has been determined to be BACT for a different type of source but which is similar in operation and has similar air contaminant emissions. If a BACT determination cannot be arrived at from the first two tiers, then the Agency relies on a rigorous technical and economic evaluation of alternative air pollution controls, taking into account energy, environmental and

economic impacts. This third tier requires the documentation of performance levels and technical limitations of each air pollution control technology evaluated. Associated material, energy, and economic penalties associated with the alternative controls, as well as the environmental benefits derived from these systems are also evaluated. The first tiered approach has been used in this evaluation to demonstrate compliance with the BACT requirements of the TNRCC.

Information with regard to previous BACT determinations for a project of this type and size was gathered from several different sources. These sources included a review of the BACT/LAER Clearinghouse, the EPA's electronic bulletin board, discussions with the TNRCC air quality staff with regard to previous PSD determinations, and information from equipment manufacturers. Included in Appendix A are copies of excerpts from the BACT/LAER Clearinghouse and information obtained from the EPA bulletin board which were pertinent to this evaluation. A listing from the TNRCC of NO_x limitations incorporated in permits issued for gas turbine facilities rated at 20 MWe or greater of electrical output is also included. Appendix F includes guarantees of performance from equipment manufacturer's. These sources of information formed the basis for the following BACT evaluation.

3.0 CONTROL OF NITROGEN OXIDE EMISSIONS

The formation of nitrogen oxides occurs from the combustion process in two ways. One is through the combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor. NO_x formed in this way is referred to as "thermal NO_x". The other way NO_x is formed is through the oxidation of nitrogen contained in the fuel, referred to as "fuel NO_x". Neither the natural gas or fuel oil (diesel) proposed for the gas turbine/HRSGs and the auxiliary boiler contains a significant amount of nitrogen. Therefore, the bulk of the NO_x emissions will originate as thermal NO_x.

The rate of formation of thermal NO_x is a function of the residence time, free oxygen, and peak flame temperature. Therefore, some NO_x control techniques are aimed at minimizing one or more of these variables to reduce NO_x. Other control methods, known as "tail gas" or "back-end" techniques remove NO_x from the exhaust gas stream after NO_x has been formed.

3.1 CONTROL OF NO_x EMISSIONS FROM THE GAS TURBINE/HRSG UNITS

Based on a review of previous BACT determinations and on discussions with the TNRCC, the most stringent method for the control of NO_x emissions from a gas turbine/HRSG system is a combination of steam injection in the turbines and the use of Selective Catalytic Reduction (SCR) at the back-end of the system.

In the SCR process, ammonia injected into the gas turbine exhaust gas reacts with NO_x and oxygen in the exhaust gas to form nitrogen and water. The chemical reactions

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

and

$$6\ NO_2 + 8\ NH_3 \rightarrow 7\ N_2 + 12\ H_2O$$

take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. The optimum operating temperature for most SCR systems has been shown to be in the range of 500 to 850° F.

In the catalyst bed, blocks of catalyst elements are assembled together to fill the full cross-section of the HRSG. The blocks are oriented perpendicular to the turbine exhaust gas flow such that the entire exhaust gas stream flows uniformly through the catalyst unit. The catalyst will be installed between the tube bundles within the HRSG so that exhaust gas passing through the catalyst is in the catalyst's most active temperature range.

Catalyst systems will promote the oxidation of sulfur dioxide to sulfur trioxide (SO_3), which combines with water to form sulfuric acid. The proposed cogeneration project will burn low sulfur fuels which will minimize sulfuric acid formation. Excess ammonia injected into the exhaust gas will largely neutralize the acid to form ammonium sulfate which is assumed to be emitted as particulate matter. Therefore, sulfuric acid formation should not be of concern.

The SCR system will be designed for a nominal 80% reduction of flue gas NO_x emissions when firing natural gas and a nominal 77% reduction when firing fuel oil. No more than 10 ppm of unreacted ammonia will remain in the flue gas.

To assist in achieving these low NO_x emission rates from the gas turbine/HRSG, a staged approach will be utilized whereby the initial NO_x removal will be achieved by the injection of steam into the turbine. When natural gas is fired, NO_x emissions from the gas turbines will be controlled to 42 ppmvd (corrected to 15% oxygen (O_2)) by steam injection into the turbine combustors. When fuel oil is fired gas turbine NO_x emissions will be controlled to 65 ppmvd (corrected to 15% O_2) by steam injection into the turbine combustors.

Low emissions combustion systems will also be used in the HRSG duct burners to minimize NO_x emissions. The proposed NO_x control technique for the duct burners is modern burner design, such that NO_x emission rates will not exceed 0.08 lb NO_x/MMBtu heat input (HHV). The duct burners will be fired with only natural gas.

As discussed above, the NO_x concentration in the gas turbine/HRSG exhaust will be further reduced by the use of a selective catalytic reduction (SCR) system which will be installed in the HRSG downstream of the duct burner. The final NO_x concentration at the HRSG exhaust stack will be controlled to 9 ppmvd (corrected to 15% O_2) when firing natural gas and 15 ppmvd (corrected to 15% O_2) when firing fuel oil (see equipment manufacturer's guarantees in Appendix F). The implementation of these combined technologies is designed to perform in accordance with, or better than, Environmental Protection Agency (EPA) and TNRCC guidelines for BACT for large gas turbine/HRSG systems.

3.2 CONTROL OF NO_x EMISSIONS FROM THE AUXILIARY BOILER

As with the gas turbine/HRSG systems, emissions of NO_x from the auxiliary boiler will be primarily thermal NO_x as only natural gas or fuel oil will be fired. In addition, the boiler will only be used as a backup source of steam for the adjacent industrial facility should the gas turbine/HRSG go down and will therefore not be operated on a year-round basis.

3.2.1 Selective Catalytic Reduction Technology

The use of SCR can also be considered the most stringent NO_x control technique applicable to the auxiliary boilers. However, it is not generally applied a boiler in the capacity range as that of the boiler proposed for this project. This is due to the significant capital and operating expenses involved and the relatively low potential for emissions reduction for small capacity boilers.

3.2.2 Selective Non-Catalytic Reduction Technology

The second most stringent NO_x control technique is selective non-catalytic reduction (SNCR). SNCR involves the non-catalytic decomposition of NO_x in the flue gas to nitrogen and water using ammonia as a reducing agent. This control technology is based on a gas phase reaction between the reducing agent and NO_x within a specific temperature range (1600 to 2200° F). Achieving the required reaction temperature range within the boiler flue gas represents the primary problem with utilization of this technology. The necessary temperature range is found in different areas of a boiler depending on its design and operating load. Size constraints imposed in a particular application are also a significant design factor. Size constraints are primarily related to the size of the combustion chamber and the difficulty of locating the injection nozzles to provide the necessary time/temperature relationships required of this technology. Because of these problems, the use of SNCR is also not considered representative of BACT for the proposed auxiliary boiler.

3.2.3 Combination Low-NO_x Burner/Flue Gas Recirculation Technology

Tenaska proposes to achieve the necessary NO_x control in the auxiliary boiler through the use of low-NO_x burners in combination with flue gas recirculation. The low-NO_x burner is designed to split the combustion flame into two zones thereby decreasing NO_x formation. As the boiler will be fired with primarily natural gas with fuel oil backup, a combination staged air and/or staged fuel burner will be utilized. The staged air burner is designed to split the combustion flame by diverting a portion of the combustion air downstream of the primary fuel injection point when

burning natural gas. The staged fuel burner splits the combustion flame by dividing the fuel flow into two zones when firing fuel oil.

The formation of NO_x is suppressed in the staged air burner by the promotion of a fuel-rich primary combustion zone, followed by complete combustion in the secondary combustion zone. The lack of excess air in the primary zone limits NO_x formation. Incomplete combustion products formed in this primary zone act as reducing agents in the secondary combustion zone. The staged fuel burner combustion approach works by lowering the peak flame temperature in the fuel-lean primary zone. Complete combustion is then accomplished in the secondary zone. Combustion products from the primary zone act to lower the local oxygen concentration in the secondary, thereby suppressing NO_x formation in this zone as well.

Flue gas recirculation involves recycling a portion of the auxiliary boiler flue gas and returning it to the boiler through the burner or windbox. The primary effect of this technique is a reduction of the peak flame temperature in the burner through absorption of the combustion heat by the relatively inert flue gas. In addition, the flue gas reduces the oxygen concentration in the combustion air, effecting a reduction in thermal NO_x formation by decreasing oxygen availability.

The effectiveness of this control method depends on the fuel being fired. Since flue gas recirculation reduces NO_x formation by targeting peak flame temperature, it has little effect on fuel NO_x formation, thus it is less effective on fuels with a high nitrogen content. In addition, the NO_x reduction efficiency is directly related to the flue gas recirculation rate. Typically an increase in the recirculation rate results in a corresponding decrease in thermally generated NO_x. Beyond 20% recirculation, however, the effectiveness begins to diminish as flame stability becomes a problem.

Utilizing the combination of low-NO_x burner/flue gas recirculation technique, the NO_x emissions from the auxiliary boiler will be reduced to a maximum of 0.06 lb NO_x/MMBtu when burning natural gas and to a maximum of 0.1 lb NO_x/MMBtu when burning fuel oil (see equipment manufacturer guarantees in Appendix F). As the boiler will be operated only as a backup to the gas turbine/HRSG system, the implementation of these combined technologies is designed to

perform in accordance with, or better than, EPA and TNRCC guidelines for BACT for auxiliary boilers of this type.

3.3 ALTERNATIVE NO_x CONTROL TECHNOLOGIES

Tenaska has reviewed the available applicable control alternatives which have been used to control NO_x emissions. The review indicates that the proposed technologies have been successful in reducing NO_x emissions. In addition to the potential for lower NO_x emissions, the proposed technologies will offer several major operating and economic benefits as they are simple, stable processes with high reliability and low maintenance requirements.

4.0 CONTROL OF CARBON MONOXIDE EMISSIONS

Carbon monoxide is formed as a result of the incomplete combustion of fuel and is a function of oxygen availability, flame temperature, residence time at flame temperature, combustion zone design and turbulence. Control of CO is thus accomplished by providing adequate fuel residence time and sufficiently high temperature in the combustion device to ensure complete combustion. These control factors, however, could result in high emissions rates of NO_x. Conversely, a low NO_x emissions rate achieved through flame temperature control; i.e., by steam injection, can result in higher levels of CO emissions. Thus, a compromise is established whereby the flame temperature reduction is set to achieve the lowest NO_x emissions rate possible while keeping the CO emission rates at acceptable levels.

4.1 CONTROL OF CO EMISSIONS FROM THE GAS TURBINE/HRSG SYSTEMS

4.1.1 Catalytic Oxidation Technology

The most stringent method of CO control for the gas turbine/HRSG may be achieved through the use of a catalytic oxidation reactor which oxidizes the CO in the gas stream to CO_2. As with the SCR technology, catalytic oxidation reactor systems are utilized to remove pollutants at the back-end of the gas turbine/HRSG system rather than limiting pollutant formation at the front-end. CO catalytic oxidation technology does not require the introduction of additional

chemicals for the reaction to proceed. The oxidation reaction uses excess air or oxygen in the gas turbine exhaust in the presence of the catalyst; the catalyst serving to reduce the activation energy required for the reaction.

As with the SCR technology, CO catalytic oxidation reactors are required to operate within a relatively narrow temperature range. Optimum operating temperatures for these systems generally fall into the range of 700 to 1100° F. At lower temperatures, CO conversion efficiency falls off rapidly. Above 1200° F, catalyst sintering may occur, thus causing permanent damage to the catalyst. Maintaining operation within this required temperature range is a concern. In addition, pressure losses across an oxidation catalyst reactor result in a loss in power output and fuel efficiency. Because of these problems, the use of the CO catalytic oxidation is not considered representative of BACT for the proposed gas turbine/HRSG systems.

4.1.2 Combustion Controls

Tenaska proposes to achieve the necessary CO control through the use of proper combustion control. By operating the gas turbine/HRSG systems properly to insure good combustion, Tenaska will keep CO emissions from the gas turbines to a minimum. In addition, the duct burners will be designed such that they will achieve a maximum of 0.10 lb CO per MMBtu (HHV) when burning either natural gas or fuel oil. This control method is proven reliable, does not carry additional economic impact, and does not result in increased emissions for other pollutants. These levels of control are consistent with what has been established to be BACT for the control of CO from gas turbines and duct burners by the EPA and the TNRCC. Therefore, the use of proper design and operation of the gas turbines and duct burners is BACT for the control of CO emissions from the gas turbine/HRSG systems.

4.2 CONTROL OF CO EMISSIONS FROM THE AUXILIARY BOILER

As with the gas turbine/HRSG units, emissions of CO are derived from the incomplete combustion of the natural gas or fuel fired. The boiler will be properly designed so as to minimize formation or remove CO from the exhaust gas. In addition, the boiler will only be operated as a

backup source of steam for the adjacent industrial facility and will not be operated continuously on a year-round basis.

4.2.1 Catalytic Oxidation Technology

Catalytic oxidation technology can be considered the most stringent CO control technique applicable to the auxiliary boilers. However, it is not generally applied to a boiler in the capacity range proposed for this project. Boilers in the size range proposed for this project firing natural gas or fuel typically do not generate large quantities of CO emissions, thus, the cost effectiveness of this alternative is typically poor considering the relatively low potential for emissions reduction. Therefore, catalytic oxidation is not considered representative of BACT for the auxiliary boiler.

4.2.2 Combustion Controls

The auxiliary boiler will be equipped with high efficiency burners which will limit the formation of CO by providing for high efficiency combustion of fuels. The auxiliary boiler burners will be designed such that they will achieve a maximum of 0.18 lb CO/MMBtu when burning either natural gas or fuel oil (see equipment manufacturer's guarantee in Appendix F). As the boiler will not be operated on a continuous basis, the use of proper burner design and combustion control is BACT for the control for CO emissions from the auxiliary boiler.

5.0 CONTROL OF VOLATILE ORGANIC COMPOUND EMISSIONS

Volatile organic compounds are emitted from the gas turbine/HRSG systems and the auxiliary boiler as a result of incomplete combustion of fuel. Control of VOC emissions is primarily accomplished by providing adequate fuel residence time and sufficiently high temperature in the combustion device to ensure complete combustion.

5.1 CONTROL OF VOC EMISSIONS FROM THE GAS TURBINE/HRSG SYSTEMS

5.1.1 Catalytic Oxidation Technology

As with the control of CO emissions, VOC control for the gas turbine/HRSG may be achieved through the use of a catalytic oxidation reactor which oxidizes the unburned hydrocarbons in the gas stream to CO_2. The VOC catalytic oxidation reactors are utilized at the back-end of the gas turbine/HRSG system rather than limiting pollutant formation at the front-end. VOC catalytic oxidation technology does not require the introduction of additional chemicals for the reaction to proceed. The oxidation of unburned hydrocarbons to CO_2 uses the excess air or oxygen in the gas turbine exhaust for oxidation in the presence of the catalyst.

VOC catalytic oxidation reactors are required to operate within a relatively narrow temperature range. At temperatures below 1000° F, very little VOC is expected to oxidize. Above 1200° F, catalyst sintering may occur, thus causing permanent damage to the catalyst. Maintaining operation within this required temperature range is a concern. In addition, pressure losses across an oxidation catalyst reactor result in a loss in power output and fuel efficiency. Because of these problems, the use of the VOC catalytic oxidation is not considered representative of BACT for the proposed gas turbine/HRSG systems.

5.1.2 Combustion Controls

Tenaska proposes to achieve VOC control through the use of proper combustion control. By operating the gas turbine/HRSG systems properly to insure good combustion, Tenaska will keep VOC emissions from the gas turbine/HRSG units to a minimum. This control method is proven reliable, does not carry additional economic impact, and does not result in increased emissions for other pollutants. Therefore, the use of proper design and operation of the gas turbines and duct burners is BACT for the control of VOC emissions from the gas turbine/HRSG systems.

5.2 CONTROL OF VOC EMISSIONS FROM THE AUXILIARY BOILER

As with the gas turbine/HRSG units, emissions of VOC are derived from the incomplete combustion of the natural gas or fuel fired. The boiler will be properly designed so as to minimize formation or remove VOC from the exhaust gas. In addition, the boiler will only be operated as a backup source of steam for the adjacent industrial facility and will not be operated continuously on a year-round basis.

5.2.1 Catalytic Oxidation Technology

Catalytic oxidation technology can be considered as a technique applicable to the auxiliary boilers. However, it is not generally applied to a boiler in the capacity range proposed for this project. Boilers in the size range proposed for this project firing natural gas or fuel typically do not generate large quantities of VOC emissions, thus, the cost effectiveness of this alternative is typically poor considering the relatively low potential for emissions reduction. Therefore, catalytic oxidation is not considered representative of BACT for the auxiliary boiler.

5.2.2 Combustion Control

As discussed above, the auxiliary boiler will be equipped with high efficiency burners which will limit the formation of VOC by providing for high efficiency combustion of fuels. The auxiliary boiler burners will be designed such that they will achieve a maximum of 0.006 lb VOC/MMBtu when burning natural gas and 0.01 lb VOC/MMBtu when firing fuel oil (see equipment manufacturer's guarantee in Appendix F). As the boiler will not be operated on a continuous basis, the use of proper burner design and combustion control is BACT for the control for VOC emissions from the auxiliary boiler.

6.0 CONTROL OF PM/PM_{10} EMISSIONS

Particulate emissions from the project will consist of ash from the fuel, particulate of carbon and hydrocarbons resulting from incomplete combustion, and ammonium salts formed in the reaction of SO_3 and ammonia. As the units are designed to fire fuels with low ash contents

and high combustion efficiency, they will have correspondingly low particulate matter emission rates.

6.1 CONTROL OF PM/PM_{10} EMISSIONS FROM THE GAS TURBINE/HRSG UNITS

Typical particulate control devices such as electrostatic precipitators (ESPs) and baghouse filters are not suitable for use with gas turbines/HRSG units due to both the extremely low particulate emission concentration as well as the physical characteristics of the particles emitted. For ESPs which operate on the principal of charge migration, the low particulate concentration would prevent significant charge buildup on particles and thus, low migration of particles to collecting plates. In addition, the particulate matter resulting from oil or natural gas firing is typically hygroscopic, thus not suitable for a baghouse filter as it would tend to adhere to the bags and not be easily dislodged as required for periodic cleaning of the bags. Therefore, the use of ESPs or baghouse filters is considered technically infeasible and thus, not representative of BACT.

Tenaska proposes to use proper combustion techniques to ensure that the PM/PM_{10} emissions from the gas turbine/HRSG units will be minimized. PM/PM_{10} emissions resulting from ammonium sulfate formation will be minimized by utilizing low sulfur fuels and minimizing excess ammonia injected into the exhaust gas. In addition, burning of the fuel oil will be limited to only 720 hours per year. The use of proper combustion control and low sulfur, low ash fuels is representative of BACT for this project as these controls have been determined to be BACT in controlling PM/PM_{10} emissions from gas turbines and duct burners by the EPA and the TNRCC in previously issued permits.

6.2 CONTROL OF PM/PM_{10} EMISSIONS FROM THE AUXILIARY BOILER

As with the control of particulate matter emissions from the gas turbine/HRSG systems, traditional particulate matter control devices are not generally used on boilers of the size and firing the type of fuels proposed for this project.

Tenaska proposes to use proper combustion techniques to ensure that the PM/PM_{10} emissions from the auxiliary boiler will be minimized. The use of proper combustion control and low ash fuels has been determined to be BACT in controlling PM/PM_{10} emissions from boilers by the EPA and the TNRCC in previously issued permits. In addition, burning of the fuel oil will be limited to only 720 hours per year. Therefore, combustion control is BACT for the control of PM/PM_{10} emissions from the auxiliary boiler.

7.0 CONTROL OF SO_2 EMISSIONS

Sulfur dioxide is exclusively formed through the oxidation of the sulfur present in the fuel. The emission rate of SO_2 is a function of the combustion efficiency of the source and the sulfur content of the fuel, since virtually all fuel sulfur is converted to SO_2.

7.1 CONTROL OF SO_2 EMISSIONS FROM THE GAS TURBINE/HRSG SYSTEMS

The gas turbines will primarily use natural gas and will use low sulfur fuel oil (less than 0.05 %wt) only as a backup fuel. The use of the fuel oil will be limited to 720 hours per year. The duct burners will only be fired with natural gas. The use of low sulfur content gaseous and diesel fuels has been determined to be BACT in controlling SO_2 emissions by the TNRCC and the EPA in previously issued permits. Therefore, the use of low sulfur fuels is BACT for the control of SO_2 emissions from the gas turbine/HRSG systems.

7.2 CONTROL OF SO_2 EMISSIONS FROM THE AUXILIARY BOILER

The auxiliary boiler will also be designed with dual fuel capability. Although the boiler will be fired primarily with natural gas, it may be fired with low sulfur (0.05 %wt) fuel oil up to 720 hours per year. The use of low sulfur content gaseous and diesel fuels has been determined to be BACT in controlling SO_2 emissions by the TNRCC and the EPA in previously issued permits. Therefore, the use of low sulfur fuels is BACT for the control of SO_2 emissions from the auxiliary boiler.

8.0 CONTROL OF DIESEL STORAGE TANK EMISSIONS

The two 35,000-barrel diesel fuel storage tanks will be used to store diesel fuel having a very low vapor pressure. Emissions from these tanks will be minimized by the use of fixed-roof tanks. Because of the low vapor pressure of the fuel and the expected low rate of emissions, the use of fixed-roof tanks is BACT for these facilities and no additional controls are necessary.

9.0 CONTROL OF ANHYDROUS AMMONIA STORAGE TANK EMISSIONS

Anhydrous ammonia will be stored in a 12,000 gallon pressure vessel. As a result, there will be no emissions from this tank. The use of a pressure vessel is BACT for this facility and no additional controls are necessary.

10.0 CONTROL OF SULFURIC ACID STORAGE TANK EMISSIONS

Emissions from the 6,000 gallon sulfuric acid storage tank will be minimized by the use of a horizontal tank which operates at atmospheric pressure. Because the sulfuric acid will have a very low vapor pressure, emissions from this tank will be very low. Therefore, the use of a fixed-roof tank is BACT for this facility and no additional controls are necessary.

11.0 CAUSTIC STORAGE TANK

The 6,000 gallon caustic storage tank will be a horizontal storage tank which will contain a 50% wt sodium hydroxide solution. Because this solution will have a very low vapor pressure, emissions from this tank are estimated to be negligible. Because of the low emission rates, no additional control is BACT for this tank.

12.0 EMERGENCY FIRE PUMP ENGINES

Tenaska will utilize one 200-hp diesel-fired engine in case of fire. It is expected that this engine will be used only in emergencies, but it will also be operated for testing purposes a maximum of 20 minutes once per week. In addition, the sulfur content of the fuel oil will be very

low. Because of the limited hours of operation, no additional control beyond the proper operation of these engines is BACT for these facilities.

13.0 CONCLUSION

Based on the factors discussed above, Tenaska believes it has demonstrated BACT for controlling emissions from the proposed cogeneration project.

Kapny, Huston & Associates, Inc.

ITEM VI.E
FRANCHISE TAX STATEMENT

[illegible]

EH&A
Espey, Huston & Associates, Inc.

ITEM VI.E
FRANCHISE TAX STATEMENT

As Tenaska IV Texas Partners, Ltd. is a limited partnership, it is not required to pay a corporate franchise tax to the State of Texas. However, once a Certificate of Existence is received from the Secretary of State's office, Tenaska will provide a copy to the TNRCC.

Espey, Huston & Associates, Inc.

ITEM VI.F

PERMIT FEE STATEMENT

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EH&A
Espey, Huston & Associates, Inc.

ITEM VI.F
PERMIT FEE STATEMENT

The project will require a TNRCC air quality permit and a Prevention of Significant Deterioration permit. The capital cost of the project will exceed $15 million. Therefore, a check for $75,000, the maximum permit fee required under 31 TAC 116.163 has been remitted with this application.

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EH&A
Espey, Huston & Associates, Inc.

ITEM VII.A
PROCESS FLOW DIAGRAM

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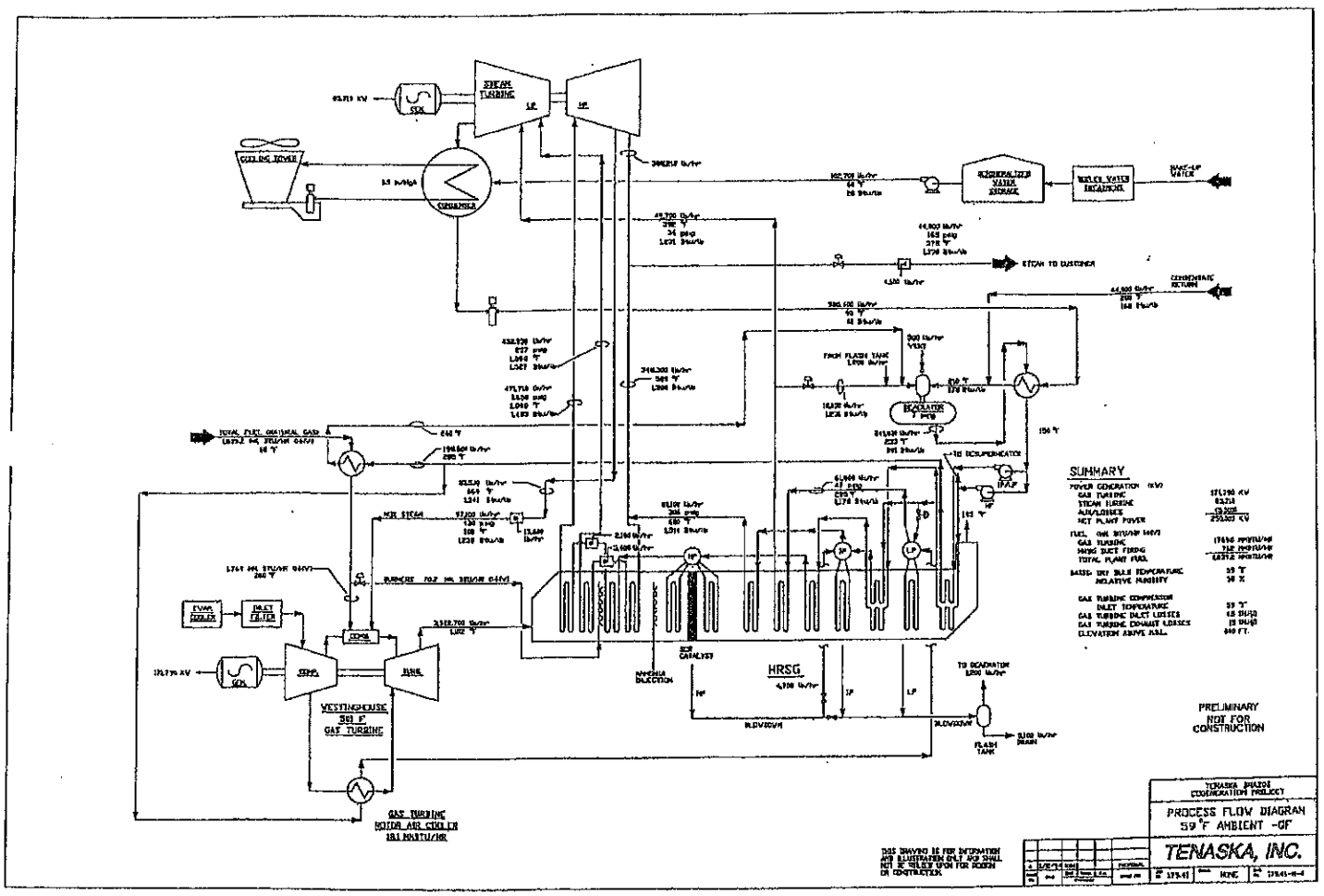
STEAM TURBINE
LP
HP
GEN
COOLING TOWER
CONDENSER
GENERALIZED WATER STORAGE
BOILER WATER TREATMENT
MAKE-UP WATER
STEAM TO CUSTOMER
CONDENSATE RETURN
FROM FLASH TANK
DEAERATOR
TO DESUPERHEATER
TOTAL FUEL (NATURAL GAS)
NOX STEAM
BURNERS
EVAP. COOLER
INLET FILTER
COMB.
COMP.
TURB.
WESTINGHOUSE 501 F GAS TURBINE
GAS TURBINE MOTOR AIR COOLER
HRSG
SCR CATALYST
AMMONIA INJECTION
BLOWDOWN
TO DEAERATOR
FLASH TANK
SUMMARY
POWER GENERATION (KW)
GAS TURBINE
STEAM TURBINE
AUX/LOSSES
NET PLANT POWER
FUEL
GAS TURBINE
HRSG DUCT FIRING
TOTAL PLANT FUEL
BASIS: DRY BULB TEMPERATURE
RELATIVE HUMIDITY
GAS TURBINE COMPRESSOR
INLET TEMPERATURE
GAS TURBINE INLET LOSSES
GAS TURBINE EXHAUST LOSSES
ELEVATION ABOVE M.S.L.
PRELIMINARY
NOT FOR CONSTRUCTION
TENASKA AMAZOS COGENERATION PROJECT
PROCESS FLOW DIAGRAM
59°F AMBIENT -OF
TENASKA, INC.
HUNE

Espey, Huston & Associates, Inc.

ITEM VII.B
PROCESS DESCRIPTION

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ITEM VII.B
PROCESS DESCRIPTION

The project will consist of two Westinghouse 501F gas turbine electric generating units each of which exhausts into it associated duct burner-fired heat recovery steam generator unit (HRSG) which will be used to generate steam and electricity. Two steam turbines with a nominal combined output of 208 MWe will be constructed to use steam produced in the HRSG. The project will have a combined electric generation nominal plant output of 500 MWe with over 95% of its electric power production being sold to an electric utility company. Each gas turbine/HRSG/steam turbine unit will be fully dispatchable from approximately 80 MWe to 250 MWe by automatic generation control at a loading/unloading rate which will be at least 5% per minute. The cogeneration project will be designed to operate at a maximum of 8,760 hours per year. The steam produced will be sold to an adjacent industrial facility. To serve as a backup source of steam for the adjacent industrial facility, an auxiliary boiler with a maximum fuel input of about 156 MMBtu/hr will be constructed.

A detail of project milestones is shown in Table VII.B-1. The desired permit issuance date of November 1994 is necessary for the project to complete financing by January 1995. The following subsections briefly describe key plant components. These components are shown on the Plot Plan and Plot Plan Detail in Item VI.B of this application. TNRCC Equipment Tables for the various equipment may be found in Appendix B.

1.0 GAS TURBINE UNITS

The cogeneration project will include two Westinghouse 501F gas turbine packages each capable of generating 172 MWe (nominal) of electrical output. In the gas turbine, air will be drawn in, compressed and forced into the turbine where it will be mixed with natural gas or fuel oil for combustion. Natural gas will be the primary fuel for the gas turbines with fuel oil (diesel) used as backup fuel. The fuel oil will be limited to a sulfur content of 0.05%wt or less. Steam will be injected into the turbine combustors to reduce the NO_x emissions. The steam injection rate will

TABLE VII.B-1

MILESTONE SCHEDULE

Sign Power Sales Agreement	November 1993
File Environmental Permit Applications	June 1994
EPC Contractor Selection	August 1994
Environmental Permits Issued	November 1994
Financial Closing	January 1995
Release Major Equipment Manufacturing	January 1995
EPC Contract On-Site Mobilization	June 1995
Steam Turbine Delivery	April 1996
Gas Turbine Delivery	July 1996
Switchyard Energized	November 1996
First Power	January 1997
Commercial Operation	March 1997

be controlled by a steam-to-fuel ratio controller. The compressed mixture of air and combustion products will then expand through the power turbine, converting thermal energy to mechanical energy. This mechanical energy will rotate both the compressor used to compress inlet air and the electrical generator to produce electrical energy. Exhaust gas will exit each power turbine at approximately 1,100° F and will be sent to its associated HRSG.

2.0 HEAT RECOVERY STEAM GENERATOR (HRSG)

The hot exhaust gases from each gas turbine unit will flow to its associated HRSG unit. Exhaust gas entering the HRSGs at approximately 1,100° F will be cooled to approximately 190° F when it leaves the HRSGs, with the heat recovered to heat feedwater and to generate steam. Duct burners will be installed within the HRSGs so additional heat can be added to the HRSGs when necessary. The gas turbine exhaust gas contains sufficient oxygen to support combustion at the duct burner and therefore, external combustion air to the HRSG burners will not be required. As shown on the Process Flow Diagram in Item VII.A of this application, the HRSGs will contain different sections which are used to recover heat and generate steam. The HRSG sections will be arranged so that the operating temperature of the sections progressively drop as the exhaust gases are cooled.

Each duct burner system will be sized for a maximum of 450 MMBtu/hr HHV heat input. The duct burners will be fired with only natural gas. The steam from the HRSG will be used to drive its associated 104 MWe steam turbine. Steam for export to the steam host will be temperature and pressure controlled to the steam host's specifications. Steam for injection into the gas turbine combustors for nitrogen oxides (NO_x) control will be extracted from the steam turbine and desuperheated and pressure controlled to about 360 psig, 475° F.

The duct burners will be used to compensate for reduced turbine-generator output due to higher ambient temperature, increased steam sales demand, or degraded gas turbine performance. Plant output will be maintained at the 500 MWe nominal net plant capacity by regulating duct burner firing and generating the appropriate quantity of high pressure steam to produce the required steam turbine-generator output.

3.0 SELECTIVE CATALYTIC REDUCTION (SCR)

A Selective Catalytic Reduction (SCR) system will be installed within each HRSG to reduce NO_x emissions. In the SCR process, ammonia injected into the gas turbine exhaust gas reacts with NO_x and oxygen in the exhaust gas to form nitrogen and water. The chemical reactions

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

and

$$6\ NO_2 + 8\ NH_3 \rightarrow 7\ N_2 + 12\ H_2O$$

will take place on the surface of a catalyst. Blocks of catalyst elements will be assembled together to fill the full cross-section of the boiler, so that the entire exhaust gas stream flows uniformly through the catalyst unit. The catalyst unit location within the HRSG will be selected so that exhaust gas passing through the catalyst is in the catalyst's most active temperature range.

The SCR system will include the assembled blocks of catalyst elements, an anhydrous ammonia storage tank (12,000 gallon), ammonia vaporizer, accumulator, ammonia/air mixer, air fan, ammonia distribution grid upstream of the catalyst in the HRSG, and flow controls. The SCR will be designed for a nominal 80% reduction of flue gas NO_x emissions when firing natural gas and a nominal 77% reduction when firing fuel oil. No more than 10 ppm of unreacted ammonia will remain in the flue gas.

4.0 STEAM TURBINE AND CONDENSER

Steam produced in each HRSG will be expanded through nominal 104 MWe steam turbines, driving generators to produce electric power. Steam leaving the steam turbines will then be directed to the condensers and recycled back to the HRSGs.

5.0 AUXILIARY STEAM BOILER

An auxiliary steam boiler will be installed to serve as a backup source of steam for the adjacent industrial facility. The boiler will be designed to produce up to 130,000 lb/hr of steam and

will use primary natural gas with fuel oil as backup at a maximum firing rate of about 156 MMBtu/hr. NO_x emissions from the boiler will be reduced by the use of a low-NO_x burner combined with flue gas recirculation which involves extracting a portion of the boiler flue gas and returning it to the burner.

6.0 COOLING TOWER

Non-contact cooling water used to condense turbine exhaust steam in the condenser and for other plant cooling needs will be recycled through a cooling tower where heat will be rejected to the atmosphere. Treated effluent from the City of Cleburne's sewage treatment plant will be used for cooling tower makeup.

7.0 FUEL OIL STORAGE/HANDLING

Two 35,000 barrel fuel oil tanks will be provided. The fixed-roof welded steel tanks will operate at atmospheric pressure. Two 100 percent capacity fuel oil pumps will be provided to pump from the fuel oil storage tank to the gas turbines.

Fuel oil deliveries will be made by truck. Unloading systems and pumps will be provided to unload two trucks at the same time. The unloading areas will be curbed and surfaced to contain oil spills, with drains from the unloading areas piped to an oil/water separator.

8.0 EMERGENCY GENERATOR

There will not be a diesel driven emergency generator permanently installed at the plant. Provision will be made to enable the connection of a portable 1,000 kW, three-phase diesel generator to the plant's electrical system in the event that the plant is shut down and utility power is out of service. The diesel engine driven generator will burn the same fuel oil used as gas turbine backup fuel.

9.0 FIRE PROTECTION SYSTEM PUMPS

A fire water system sized to deliver 2,000 gpm of water will be provided to protect plant facilities against fire. The system will include a fire water supply loop; fire hydrants, fire monitors, and hoses located at appropriate locations. One 200 hp diesel fire pump and one electric drive fire pump will be installed to maintain the required fire water pressure.

10.0 STACK

One stack approximately 18 feet in diameter and 110 feet high will be provided at each HRSG exhaust. The stack will have monitoring ports and an access platform.

11.0 MISCELLANEOUS EQUIPMENT

The proposed generation facility will include the following miscellaneous equipment:

- air compressors, dryers, and receivers for instrument and plant air systems
- continuous boiler blowdown tanks vented to the deaerators, and boiler blowdown tanks vented to the atmosphere
- lubrication oil storage tank(s) with transfer pump(s)
- chemical feed skids with tanks, mixers, and feed pumps for boiler and feedwater treatment, and for cooling water treatment
- control room mechanical equipment including air handling unit, hot water heater, locker rooms and fire extinguishers

12.0 CHEMICAL STORAGE

Chemicals will be transported to the site by truck. Storage volumes provided are determined by rates of consumption, customary delivery volumes available from suppliers, and the reliability of supply.

12.1 AMMONIA STORAGE

Anhydrous ammonia for use with the SCR system for control of NO_x emissions will be stored in a 12,000 gallon welded steel pressure tank designed to operate without emissions to the atmosphere. The ammonia tank will be designed and tested for 250 psig internal pressure in accordance with Section VIII of the ASME Boiler and Pressure Vessel Code. Pressure within the ammonia tank will vary with ambient temperature, from 16 psig at 0° F to 197 psig at 100° F.

12.2 SULFURIC ACID STORAGE

Sulfuric acid for demineralizer regeneration and cooling tower pH control will be stored in a 6,000 gallon welded steel horizontal tank. The acid will be stored at a 93% concentration. The acid tank will be operated at atmospheric pressure.

12.3 CAUSTIC STORAGE TANK

Caustic soda (sodium hydroxide) for demineralizer regeneration will be stored in a 6,000 gallon welded steel horizontal tank. The caustic will be stored at a 50% concentration. The caustic tank will be operated at atmospheric pressure and will be located indoors.

12.4 BOILER AND COOLING TOWER WATER TREATMENT CHEMICAL STORAGE

Chemicals for boiler feedwater treatment and cooling tower water treatment will be stored indoors in small tanks. Three storage tanks are anticipated for boiler feedwater chemicals and two storage tanks for cooling water chemicals.

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ITEM VII.C

TNRCC MATERIAL BALANCE TABLE

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TABLE 2

MATERIAL BALANCE

Turbines/HRSGs

: material balance table is used to quantify possible emissions of air contaminants and special emphasis should be placed on potential air ..taminants, for example: If feed contains sulfur, show distrubiton to all products. Please relate each material (or group of materials) listed to its respective location in the process flow diagram by assigning point numbers (taken from the flow diagram) to each material.

LIST EVERY MATERIAL INVOLVED IN EACH OF THE FOLLOWING GROUPS	Point No. from Flow Diagram	Process Rate * (lbs/hr or SCFM) standard conditions: 70°F 14.7 PSIA. Check appropriate column at right for each process.	Measurement	Estimation	Calculation
1. Raw Materials - Input					
Air (Turbine)		3,347,082 lb/hr		X	
Wet Injection		97,100 lb/hr		X	
Makeup Water		102,700 lb/hr		X	
Anhydrous Ammonia		100 lb/hr		X	
2. Fuels - Input					
Turbine Fuel		1769.0 MMBtu/hr		X	
Duct Burner Fuel		70.2 MMBtu/hr (Avg)/ 450 MMBtu /hr (Design)		X	
Products & By-Products - Output					
Electricity		171,790 KW (turbine)		X	
Electricity		83,710 KW (steam)		X	
Steam		44,000 lb/hr		X	
4. Solid Wastes - Output		N/A			
5. Liquid Wastes - Output		N/A			
6. Airborne Waste (Solid) - Output					
Particulate		18.0 lb/hr			X
PM_{10}		17.1 lb/hr			X
7. Airborne Wastes (Gaseous) - Output (Based on design duct burner fuel)					
NO_x		63.5 lb/hr			X
CO		113.1 lb/hr			X
SO_2		18.3 lb/hr			X
VOC		18.4 lb/hr			X
Ammonia		29.1 lb/hr			

* Annualized averages based on 59°F ambient temperature and 58% relative humidity.
Note: These averages are on a per unit basis.

TABLE 2

MATERIAL BALANCE

Boiler

.s material balance table is used to quantify possible emissions of air contaminants and special emphasis should be placed on potential air contaminants, for example: If feed contains sulfur, show distrubiton to all products. Please relate each material (or group of materials) listed to its respective location in the process flow diagram by assigning point numbers (taken from the flow diagram) to each material.

LIST EVERY MATERIAL INVOLVED IN EACH OF THE FOLLOWING GROUPS	Point No. from Flow Diagram	Process Rate * (lbs/hr or SCFM) standard conditions: 70°F 14.7 PSIA. Check appropriate column at right for each process.	Measurement	Estimation	Calculation
1. Raw Materials - Input					
Air		131,602.6 lb/hr		X	
Feed Water		133,900 lb/hr		X	
2. Fuels - Input					
Fuel (Natural Gas or Fuel Oil)		156.2 MMBtu/hr		X	
3. Products & By-Products - Output					
Steam		130,000 lb/hr		X	
4. Solid Wastes - Output		N/A			
5. Liquid Wastes - Output		N/A			
6. Airborne Waste (Solid) - Output					
Particulate		1.3 lb/hr			X
PM_{10}		1.3 lb/hr			X
7. Airborne Wastes (Gaseous) - Output					
NO_X		9.8 lb/hr			X
CO		28.0 lb/hr			X
SO_2		1.4 lb/hr			X
VOC		0.98 lb/hr			X

Espey, Huston & Associates, Inc.

ITEM VIII

CONSIDERATIONS FOR GRANTING A PERMIT

ITEM VIII
CONSIDERATIONS FOR GRANTING A PERMIT

Compliance with the requirements of each section of Rule 116.111 of the TNRCC Regulation VI is discussed below as it relates to this permit application:

116.111(1) - PROTECTION OF PUBLIC HEALTH AND WELFARE

As outlined below, the emissions from the project will comply with all rules and regulations of the TNRCC and with the intent of the Texas Clean Air Act, including the protection of the health and physical property of the people. There are no schools located within 3,000 feet of the Tenaska site.

GENERAL RULES

Rule 101.4 - Nuisance

Emissions from the project will not adversely affect human health or welfare, animal life, vegetation, or property, or interfere with the normal use and enjoyment of animal life, vegetation, or property. Dispersion modeling will be performed to demonstrate compliance with all National Ambient Air Quality Standards (NAAQS) for particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon monoxide (CO) and with TNRCC property-line standards for total suspended particulate matter (TSP) and SO_2. The results of the dispersion modeling will be submitted in a separate document in support of this application after the proposed controls and emissions calculations are accepted by the TNRCC air quality staff. It is expected that the impacts resulting from the project will be in compliance with all Federal and state air quality standards.

Rule 101.5 - Traffic Hazard

Emissions from the project will not cause or have a tendency to cause a traffic hazard or to interfere with normal road use.

Rule 101.20 - Compliance with Environmental Protection Agency Standards

(1) The applicability of the New Source Performance Standards is discussed under Section 116.111(4).

(2) The applicability of the National Emission Standards for Hazardous Air Pollutants is discussed under Section 116.111(5).

(3) The applicability of the Prevention of Significant Deterioration regulations is discussed under Section 116.111(8).

Rule 101.21 - Compliance with the National Primary and Secondary Ambient Air Quality Standards

Atmospheric dispersion modeling will be performed to demonstrate that emissions from the project will not cause or contribute to an exceedance of primary or secondary NAAQS for PM_{10}, SO_2, NO_2, or CO. The results of this modeling will be provided in a future submittal to the TNRCC air quality staff.

REGULATION I - CONTROL OF AIR POLLUTION FROM VISIBLE EMISSIONS AND PARTICULATE MATTER

Rule 111.111 - Visible Emissions: Requirements for Specified Sources

(a)(1) Stationary Sources - The opacity of emissions from the project will not exceed 20% opacity averaged over a six minute period. The gas turbine/HRSG systems will be operated in accordance with manufacturer's specifications and will utilize proper combustion techniques such

that PM emissions will be minimized. The total flow rate out of each gas turbine/HRSG unit assuming 59° F ambient air at the inlet will be approximately one million actual cubic feet per minute. However, the opacity of emissions from the project will not exceed 15% averaged over a 6-minute period; therefore, an optical instrument capable of measuring the opacity of emissions from each vent will not be required by this rule.

(a)(4) Gas Flares - This permit application is not for a gas flare at this site; therefore, Rule 111.111(a)(4) is not applicable to this project.

(a)(5) Motor Vehicles - This permit application does not involve emissions from motor vehicles; therefore, Rule 111.111(a)(5) is not applicable to this project.

(a)(6) Railroad Locomotives and Ships - Railroad locomotives or ships will not operate at this project site; therefore, Rule 111.111(a)(6) is not applicable to this project.

(a)(7) Structures - The gas turbine/HRSG units will not be enclosed by a building; thus, this rule is not applicable to the project.

Rule 111.121 - Incineration

This permit application is not for an incineration device; therefore, this rule is not applicable to the project.

Rule 111.151 - Allowable Emission Limits

The maximum particulate matter emission rate from each gas turbine/HRSG will occur when firing fuel oil (diesel) and will be no more than 68.9 lb/hr compared to the corresponding allowable particulate matter emission rate specified in Rule 111.151 of 266.94 lb/hr. The effective stack height of the HRSG stack will be about 363 feet which is greater than the standard effective stack height of about 137 feet. For details of these calculations, see Appendix C.

The maximum particulate matter emission rate from the auxiliary boiler will also occur when firing fuel oil and will be no more than 7.4 lb/hr compared to the corresponding allowable particulate matter emission rate specified in Rule 111.151 of 36.38 lb/hr. The effective stack height of the HRSG stack will be about 163 feet which is greater than the standard effective stack height of about 44 feet. For details of these calculations, see Appendix C.

Rule 111.153 - Emission Limits for Steam Generator

Each HRSG unit proposed for the project will have a maximum heat input of approximately 450 MMBtu/hr and will be fired with only natural gas. Rule 111.153 is not applicable to the proposed HRSG units since a solid fossil fuel will not be burned and the maximum heat input is below 2,500 MMBtu/hr.

Rule 111.155 - Ground Level Concentration

Modeling will be performed to demonstrate that emissions from the project will not exceed the net ground level concentrations as specified in this rule. The results of this modeling will be provided in a future submittal to the TNRCC air quality staff.

REGULATION II - CONTROL OF AIR POLLUTION FROM SULFUR COMPOUNDS

Rule 112.3 - SO_2 Net Ground Level Concentration

Modeling will be performed to demonstrate that emissions from the project will not exceed the net ground level concentrations as specified in this rule. The results of this modeling will be provided in a future submittal to the TNRCC air quality staff.

Rule 112.9 - Allowable SO_2 Emission Rates - Combustion of Liquid Fuel

As shown in the attached emissions calculations (see Appendix C), when firing fuel oil fuel, the maximum SO_2 concentration from each gas turbine/HRSG stack will be no more than

12.6 ppmvd compared to the corresponding allowable SO_2 emission rate of 440 ppmv. However, the effective stack height is calculated to be about 363 feet which is less than the standard effective stack height of 431 feet. Therefore, the maximum allowable SO_2 concentration in the exhaust gas must be reduced to 311 ppmv in accordance with Rule 112.9(b). The SO_2 emissions from the gas turbine/HRSGs will be in compliance with this reduced standard (see Appendix C for detailed calculations). The gas turbine/HRSGs will not be equipped with SO_2 control equipment and will therefore, not be required to install a continuous emissions monitoring system for SO_2 by this rule.

Also shown in the attached emissions calculations (see Appendix C), when firing fuel oil, the maximum SO_2 concentration from the auxiliary boiler stack will be no more than 30.9 ppmvd compared to the corresponding allowable SO_2 emission rate of 440 ppmv. The effective stack height is calculated to be about 163 feet which is greater than the calculated standard effective stack height of about 76 feet. (See Appendix C for details of this calculation.) The gas turbine/HRSGs will not be equipped with SO_2 control equipment and will therefore, not be required to install a continuous emissions monitoring system for SO_2 by this rule.

REGULATION III - CONTROL OF AIR POLLUTION FROM TOXIC MATERIALS

The project is not a source of inorganic fluoride or beryllium emissions. In addition, this application does not include the construction of a nonferrous smelter or lead smelter. Therefore, Regulation III is not applicable to this facility.

REGULATION IV - CONTROL OF AIR POLLUTION FROM MOTOR VEHICLES

This permit application does not involve emissions from motor vehicles. In addition, the project will be located in Johnson County. Therefore, Regulation IV does not apply to this site.

REGULATION V - CONTROL OF AIR POLLUTION FROM VOLATILE ORGANIC COMPOUNDS

The project is located in Johnson County and is not a source subject to Regulation V; therefore, Regulation V does not apply.

REGULATION VII - CONTROL OF AIR POLLUTION FROM NITROGEN COMPOUNDS

The proposed project will be located in Johnson County and is not a source subject to Regulation VII; therefore, Regulation VII does not apply.

REGULATION VIII - CONTROL OF AIR POLLUTION EPISODES

The project will be operated in compliance with the General Rules and the applicable Air Pollution Episode requirements of Regulation VIII. Rule 118.5, Emission Reduction Plan, is not applicable to this site as it is located in Johnson County.

REGULATION IX - CONTROL OF AIR POLLUTION FROM CARBON MONOXIDE

The project will be located in Johnson County and will not involve CO emissions from any unit listed in Regulation IX; therefore, Regulation IX is not applicable.

REGULATION X - CONTROL OF AIR POLLUTION FROM HAZARDOUS WASTE OR SOLID WASTE MANAGEMENT FACILITIES

This permit application is not for a hazardous waste or solid waste management facility; therefore, Regulation X, Subchapter A does not apply. Tenaska will operate in compliance with all applicable requirements of Regulation X, Subchapter B.

REGULATION XI - CONTROL OF AIR POLLUTION FROM MUNICIPAL SOLID WASTE FACILITIES

This permit application is not for a municipal solid waste facility; therefore, Regulation XI does not apply.

REGULATION XII - FEDERAL OPERATING PERMITS

As the project will be defined as a major source under Rule 122.10, the requirements of Regulation XII will be applicable to this site. Tenaska will comply with the applicable requirements of Regulation XII and will submit an application to the TNRCC for a Federal Operating Permit as required by this rule.

116.111(2) - MEASUREMENT OF EMISSIONS

Tenaska will comply with permit provisions for measuring the emissions of significant air contaminants.

116.111(3) - BEST AVAILABLE CONTROL TECHNOLOGY

The project will utilize the best available control technology with consideration given to the technical practicability and economic reasonableness of reducing or eliminating the emissions from the facility. Section VI.D of this application contains a detailed discussion of the control technology which is utilized at this facility.

116.111(4) - FEDERAL NEW SOURCE PERFORMANCE STANDARDS

The project will be subject to NSPS Subpart Da, Db and GG, as discussed below:

Subpart D - Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971.

As discussed below, the project's duct burner-fired HRSG units are subject to Subpart Da. Therefore, the HRSG are not covered by Subpart D as provided for in 40 CFR 60.40(e).

The auxiliary boiler will have a maximum fuel input of about 156 MMBtu/hr which is less than the applicable rate of 250 MMBtu/hr as specified by this subpart for a fossil-fuel-fired steam generating unit. Therefore, the requirements of this subpart are not applicable to the auxiliary boiler.

Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978.

The proposed project's duct burner-fired HRSG units will be subject to the requirements of Subpart Da as the maximum heat input of 450 MMBtu/hr per unit exceeds the applicability level of 250 MMBtu/hr heat input based on firing only natural gas. On or after the date of the initial performance test is completed for the HRSG, particulate matter emissions from the proposed facility will not exceed the standard of 0.03 lb/MMBtu heat input for natural gas firing. The opacity of emissions from the HRSG will not exceed 20% averaged over a 6-minute period except for one 6-minute period per hour of not more than 27% as allowed by this standard. SO_2 emissions from the proposed facility will not exceed the standard of 0.8 lb/MMBtu heat input and 10% of potential combustion concentration, calculated in accordance with 40 CFR 60.41a, based on a 30-day rolling average basis. NO_x emissions from the proposed facility will not exceed the standard of 0.2 lb/MMBtu based on a 30-day rolling average basis. As shown on the vendor representations in Appendix F for the HRSG duct burners, the PM and NO_x emissions from the duct burners will not exceed 0.01 lb PM/MMBtu (HHV) and 0.08 lb NO_x/MMBtu (HHV),

respectively, when burning natural gas. Therefore, the duct burners will comply with the requirements of this subpart.

The auxiliary boiler will have a maximum fuel input of about 156 MMBtu/hr which is less than the applicable rate of 250 MMBtu/hr as specified by this subpart. Therefore, the requirements of this subpart are not applicable to the auxiliary boiler.

Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

As discussed above, the project's duct burner-fired HRSG units are subject to Subpart Da. Therefore, the HRSGs are not covered by Subpart Db, as provided for in 40 CFR 60.40b(e).

The proposed auxiliary boiler will be subject to the requirements of Subpart Db as the maximum heat input of 156 MMBtu/hr exceeds the applicability level of 100 MMBtu/hr heat input when firing either natural gas or fuel oil. As the boiler may be fired with distillate fuel oil, it is subject to the nitrogen oxides standards under this subpart. On or after the date of the initial performance test is completed for the boiler, NO_x emissions from the proposed facility will not exceed the standard of 0.2 lb/MMBtu heat input based on a 30-day rolling average basis when firing natural gas or distillate fuel oil. As shown on the vendor representations in Appendix F for the boiler burner, the NO_x emissions from the boiler will not exceed 0.06 lb NO_x/MMBtu when burning natural gas or 0.1 lb NO_x/MMBtu when burning fuel oil. Therefore, the auxiliary boiler will comply with the requirements of this subpart.

Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

As discussed above, the project's duct burner-fired HRSG units have a maximum heat input capacity of up to 450 MMBtu/hr. The auxiliary boiler has a maximum heat input capacity of 156 MMBtu/hr. These levels exceed the applicability level of 10 - 100 MMBtu/hr of Subpart Dc. Therefore, the HRSGs and the boiler are not covered by Subpart Dc, as provided for in 40 CFR 60.40c(a).

Subpart GG - Standards of Performance for Stationary Gas Turbines

The project's stationary gas turbines will be subject to the requirements of Subpart GG since the maximum heat input exceeds the applicability level of 10 MMBtu/hr (10.7 gigajoules/hr). The gas turbines will be operated so as to comply with the calculated allowable concentration of NO_x in the exhaust as contained in 40 CFR 60.332(a)(1). On or after the initial performance test is completed, SO_2 emissions from the proposed facility will not exceed the standard of 150 ppmvd contained in 40 CFR 60.333(a). Based on the emissions calculations in Appendix C, the maximum SO_2 concentration in the turbine exhaust is estimated to be 12.1 ppmvd when firing fuel oil. The fuel utilized by the gas turbine units will not contain sulfur in excess of 0.05 %wt.

Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commences After July 23, 1984

The project will include two 35,000-barrel fixed-roof tanks for the storage of fuel oil. The control requirements of Subpart Kb are not applicable to these tanks as the vapor pressure of the fuel stored is below the applicability level as contained in 40 CFR 60.110b(c). Records showing the dimensions and capacity of the tanks will be kept on site for the life of the tanks as required by 40 CFR 60.116b(a) and (b).

116.111(5) - NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs) applicable to this facility.

116.111(6) - PERFORMANCE DEMONSTRATION

It is expected that the project will achieve the performance as described in this permit application.

116.111(7) - NON-ATTAINMENT REVIEW

Johnson County has not been designated non-attainment for any criteria pollutant and the National Ambient Air Quality Standards have not been exceeded nor predicted to be exceeded; therefore, Rule 116.111(7) is not applicable.

116.111(8) - PREVENTION OF SIGNIFICANT DETERIORATION REVIEW

The proposed project is located in an attainment area and will be defined as a major source under PSD rules for CO, NO_x, PM, PM_{10}, SO_2, and VOC; therefore, the proposed project will undergo preconstruction review and permitting as required by the Federal PSD regulations for these pollutants. This permit application will address all of the elements necessary for this type of facility as required for submittal to the TNRCC for a PSD permit.

116.111(9) - AIR DISPERSION MODELING

Dispersion modeling will be performed to demonstrate compliance with all NAAQS for PM_{10}, SO_2, NO_x, and CO and with TNRCC property-line standards for TSP and SO_2. The results of the dispersion modeling will be submitted in a separate document in support of this application after the proposed controls and emissions calculations are accepted by the TNRCC air quality staff. It is expected that the impacts resulting from the project will be in compliance with all Federal and state air quality standards.

Espey, Huston & Associates, Inc.

ITEM XIII
AIR QUALITY ANALYSIS

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The air quality analysis in support of this permit application will be conducted after a preliminary determination has been made by the TNRCC Air Quality Permits Engineer that the emissions calculations and controls proposed as BACT are acceptable. This analysis will then be submitted under a separate document as a supplement to this document.

Espey, Huston & Associates, Inc.

ITEM XIV

CONTEMPORANEOUS CHANGES

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The proposed project is considered to be a "new source" under TNRCC and PSD rules. Currently, no other source exists within the project's property line. Therefore, there will be no contemporaneous emission increases or decreases associated with this permit application.

Espey, Huston & Associates, Inc.

ITEM XV
AIR QUALITY MONITORING

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AIR QUALITY MONITORING

The PSD regulations require that ambient air quality monitoring data be provided for each pollutant which will be emitted in a "significant amount", unless the predicted ambient impact caused by the proposed significant emissions is less than the prescribed significant monitoring value contained in 40 CFR 52.21(i)(8)(i). Atmospheric dispersion modeling of emissions will be conducted so as to demonstrate that either: (1) the emissions due to the project will be less than the specified significant monitoring value; or (2) the predicted ambient air quality impacts due to the non-project sources in the area will be less than the specified significant monitoring value. In the event that predicted air quality impacts are predicted to be above the specified monitoring values, the TNRCC and EPA will generally allow an applicant to use monitoring data gathered by the TNRCC or other acceptable monitoring program to satisfy the monitoring requirements, if certain criteria are met. The results of the dispersion modeling will be submitted in a separate document in support of this application after the proposed controls and emissions calculations are accepted by the TNRCC air quality staff.

Espey, Huston & Associates, Inc.

ITEM XVI

ADDITIONAL IMPACTS ANALYSIS

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ADDITIONAL IMPACTS ANALYSIS

GROWTH

It is estimated that the construction phase of the Cleburne Cogeneration Project will create 250 person-years of employment. Peak staffing during construction will be approximately 300 people with construction taking place over approximately 18 months. In addition, approximately 50 person-years of engineering staff will be required at the site. An estimated 20 to 25 permanent jobs, with a total annual payroll of $1.3 million including benefits and payroll taxes, will be created by the operation of the plant. This number does not include temporary or contract workers required for maintenance or outside support services.

It is assumed that some segment of the local unemployed work force will fill the short-term construction positions, as well as the long-term operation positions, and that no significant project-related immigration will occur. Secondary and induced financial benefits would be expected to accrue to the local economy. No significant secondary or induced impacts to local off-site land uses, community services, public infrastructures, or housing is anticipated to result from this project.

SOILS AND VEGETATION

The following background information on area soils and vegetation was taken from the Soil Survey of Johnson County, Texas, published by the U.S. Department of Agriculture (1985).

Soils in the immediate vicinity of the project site belong to the Ponder, Sanger, Slidell, Lott and Medlin series. The Ponder series consists of deep, moderately well drained, clayey soils on uplands. Slopes range from 1 to 5%. This series occupies approximately 3.8% of the county and is listed as a prime farmland soil. The Sanger series consists of deep, well drained, clayey soils on uplands. Slopes range from 1 to 5%. This series occupies approximately 7% of the county and

is listed as a prime farmland soil. The Slidell series consists of deep, well drained, clayey soils on uplands. Slopes range from 0 to 3%. This series occupies approximately 2.9% of county and is listed as a prime farmland soil. The Lott series consists of deep, well drained, clayey soils on uplands. Slopes range from 1 to 3%. This series occupies approximately .5% of the county and is listed as a prime farmland soil. The Medlin series consists of deep, well drained, clayey soils on uplands. Slopes range from 5 to 15%. This soil occupies approximately .2% of the county and is not listed as a prime farmland soil due to erosion problems and its shrink\swell characteristic.

The Ponder series occupies a Claypan Prairie site with approximately 90 % grasses, 5% forbes and 5% woody vegetation. This series, with favorable range conditions, can produce approximately 5500 pounds per acre of forage per growing season. The Sanger and Slidell Series occupy a Blackland range site with approximately 85% grasses, 10% forbes and 5% woody vegetation. These series, with favorable range conditions, can produce approximately 6,000 pounds per acre of forage per growing season. The Lott series occupies a Clay Loam range site with approximately 90% grasses, 5% forbes and 5% woody vegetation. This series, with favorable range conditions, can produce approximately 6,500 pounds per acre of forage per growing season. The Medlin series occupies an Eroded Blackland range site with approximately 85% grasses, 10% forbes and 5% woody vegetation. This series, with favorable range conditions, can produce approximately 5,000 pounds per acre of forage per growing season.

Pollutant emissions from construction activity will result in minor short-term impacts on air quality in the immediate vicinity of the project site, including increased levels of particulate matter and vehicular exhaust emissions. However, it is expected that levels of pollutants resulting from construction will remain below national ambient air quality standards (NAAQS). An air quality analysis of emissions from the project will be conducted to demonstrate compliance with the NAAQS for NO_x, CO, SO_2 and PM/PM_{10}. As a result of the project, the area classification of attainment for NO_x, CO, SO_2 and for PM/PM_{10} will not change and no long-term adverse impacts to soils or vegetation are anticipated.

VISIBILITY

The Wichita Mountains Wilderness Area in Oklahoma was modeled for visual impact screening and analysis of the plume from the cogeneration project. This area is approximately 273 kilometers (km) north-northwest from the site of the proposed project. Emissions from the project will not have an adverse impact on visibility in this PSD Class I area as demonstrated by the visibility screening modeling described below.

The visual impact of a plume from the project on the Class I area was examined using the Plume Visual Impact Screening Model (VISCREEN). The VISCREEN model was run in the Screening Level 1 mode following the guidance in EPA's Workbook for Plume Visual Impact Screening and Analysis (EPA-450/4-88-015). The PM emissions (163.34 tpy) and the NO_x emissions (599.42 tpy; assumed as NO_2) from the proposed project, assuming natural gas and fuel oil (720 hours) were used during the year, were modeled. Regional background visual ranges were input to the model following guidance from the workbook referenced above. The model was run with the default values for the remainder of the input parameters. The report generated by the VISCREEN model for the Class I area is included on the following page. The results of the modeling demonstrated that the cogeneration project will not cause any adverse or significant visual impacts on the Class I area.

Attachment H

TCEQ Permit Application Review Documents related to
TCEQ Permit No. 25384, PSDTX839

Section 1 - Document

Permit Amendment

Source Analysis & Technical Review

Company	**Brazos Electric Power Cooperative, Inc.**	Permit Number	**25384**
City	**Cleburne**	Project Number	**162448**
County	**Johnson**	Account Number	**JH-0230-L**
Project Type	**Amend**	Regulated Entity Number	**RN100223312**
Project Reviewer	**Mr. Marc Sturdivant**	Customer Reference Number	**CN600128821**
Site Name	**Johnson County Generation Facility**		

Project Overview

The Johnson County Generation Facility is an electric generating station located at 831 Sparks Dr, Cleburne, TX 76033, in Johnson County and is owned and operated by Brazos Electric Power Cooperative, Inc. (BEPC). The plant consists of a single combustion turbine equipped with a heat recovery steam generator (HRSG) unit, Emission Point No. (EPN) E-CT/HRSG, and served with ancillary equipment. BEPC wishes to amend their permit to authorize emissions from planned maintenance, startup and shutdown (MSS) activities. BEPC would like to revise Special Conditions 21A to make it clear that it is referring to base load operations, and to revise Special Condition 27A, B, and C, to define planned start-ups and shutdowns as turbine operations at less than 120 MW. MSS emissions from EPN E-CT/HRSG will be added to the MAERT as well as a new EPN MSSFUG.

Emission Summary

Air Contaminant	Current Allowable Emission Rates (tpy)	Proposed Allowable Emission Rates (tpy)	Change in Allowable Emission Rates (tpy)
PM	65.2	65.2	<0.01
PM_{10}	61.9	61.9	<0.01
$PM_{2.5}$	-	<0.01	<0.01
VOC	42.9	42.95	0.05
NO_X	272.82	272.82	<0.01
CO	462.6	462.6	0.00
SO_2	72.5	72.5	0.00
NH_3	130.5	130.5	<0.01
Pb	<0.1	<0.1	0.00

Compliance History Evaluation - 30 TAC Chapter 60 Rules

A compliance history report was reviewed on:	**April 27, 2011**
Compliance period:	**April 27, 2006-April 27, 2011**
Site rating & classification:	**5.63, Average**
Company rating & classification:	**2.69, Average**

If the rating is 40<RATING<45, what was the outcome, if any, based on the findings in the formal report:	N/A
Has the permit changed on the basis of the compliance history or rating?	No

Public Notice Information - 30 TAC Chapter 39 Rules

Rule Citation	Requirement	
39.403	Is Public Notice Required?	No
	If no, give reason:	There is no proposed change in character of emissions or the release of any new air contaminant. The emissions increases from all sources are less than the public notice de minimis levels of 30 TAC 39.402 (a)(3)

Construction Permit & Amendment Requirements - 30 TAC Chapter 116 Rules

Rule Citation	Requirement	
116.111(a)(2)(G)	Is the facility expected to perform as represented in the application?	Yes
116.111(a)(2)(A)(i)	Are emissions from this facility expected to comply with all TCEQ air quality Rules & Regulations, and the intent of the Texas Clean Air Act?	Yes
116.111(a)(2)(B)	Emissions will be measured using the following method:	NO_x and CO CEMs and NH_3 monitoring
	Comments on emission verification:	
116.111(a)(2)(D)	Subject to NSPS?	Yes
	Subparts A, Da, & GG,	
116.111(a)(2)(E)	Subject to NESHAP?	No
	Subparts &	
116.111(a)(2)(F)	Subject to NESHAP (MACT) for source categories?	Yes
	Subparts A & ZZZZ	
116.111(a)(2)(H)	Is nonattainment review required?	No
	Is the site located in a nonattainment area?	Yes
	Is the site a federal major source for a nonattainment pollutant?	Yes
	Is the project a federal major source for a nonattainment pollutant by itself?	No
	Is the project a federal major modification for a nonattainment pollutant?	No
	Did the project emission increases for nonattainment pollutant minus the two-year average actual emissions trigger netting?	No
	If yes, attach Table 1N & 9N. If no, explain:	
	Is the contemporaneous increase significant?	No
	If the contemporaneous increase is significant a nonattainment review is required.	
116.111(a)(2)(I)	Is PSD applicable?	No
	Is the site a federal major source (100/250 tons/yr)?	Yes
	Is the project a federal major source by itself?	No
	Is the project a federal major modification?	No
	Did project emission increases, without decreases, for pollutant of concern, minus the two-year average actual emissions trigger netting?	No

	Was the contemporaneous increase significant?		No
	If yes, explain:		
	Is the change excluded by 40 CFR 52.21(b)(2)(iii)?		No
	If yes, explain:		
116.111(a)(2)(L)	Is Mass Emissions Cap and Trade applicable to the new or modified facilities?		No
	If yes, did the proposed facility, group of facilities, or account obtain allowances to operate:		
116.140 - 141	Permit Fee: $ 900.00	Fee certification:	R111786

Title V Applicability - 30 TAC Chapter 122 Rules

Rule Citation	Requirement	
122.10 (13)(A)	Is the site a major source under FCAA Section 112(b)?	Yes
	Does the site emit 10 tons or more of any single HAP?	Yes
	Does the site emit 25 tons or more of a combination?	Yes
122.10 (13)(C)	Does the site emit 100 tons or more of any air pollutant?	Yes
122.10 (13)(D)	Is the site a non-attainment major source?	No
122.602	**Periodic Monitoring (PM) applicability:** Periodic monitoring is applicable because this site is subject to 30 TAC Chapter 122. Periodic monitoring of planned MSS activities in the form of recordkeeping is used for the ILE activities listed in Attachment A consisting of an annual confirmation of the estimated PTE represented for those ILE activities. Recordkeeping and CEMS are used for periodic monitoring of all other planned MSS activities in which emissions are determined based on the duration of each event and compared to the MAERT on a rolling 12 month basis.	
122.604	**Compliance Assurance Monitoring (CAM) applicability:** The site is a major source; however there are no control devices in use during MSS. Therefore, CAM is not applicable.	

Request for Comments

Received From	Program/Area Name	Reviewed By	Comments
Region:	4	Ariel Yeh/Jeremy Baum	No Comments
City:	Cleburne		N/A
County:	Johnson		N/A
Toxicology:			N/A
Compliance:			N/A
Legal:			N/A
Comment resolution and/or unresolved issues:			

Process/Project Description

The Plant is an electric generating facility consisting of a single Westinghouse 501 F combustion turbine, with a nominal output in the range of 250-270 MW, equipped with a 375- MMBtu/hr HRSG. The turbine is authorized to fire both natural gas and fuel oil, but the HRSG is authorized to fire only natural gas. The unit is authorized to operate 8760 hours per year: however, it is limited to 720 hours per year of fuel

oil firing. Emissions of NO_x are contolled through the injection of steam into the combustion turbine exhaust and with an anhydrous ammonia-based selective catalytic reduction (SCR) system. Ancillary equipment at the site includes anhydrous ammonia tank and ammonia delivery system, a fire water pump engine, a sulfuric acid tank, two fuel oil tanks, a cooling water system, and a refrigeration system.

Startups and shutdowns are regular and planned operations and during these periods, emissions of NO_x and CO can exceed the lb/hr limits of the permit. BEPC is requesting an amendment to authorize emissions of NO_x and CO from E-CT/HRSG during these startup and shutdown periods. Experience in operating the plant shows that the onset of startup is best defined as the beginning when fuel is first fed to the unit and ending when the load on the unit reaches 120 MW, approximately 44% of the 270 MW upper range of the turbine as opposed to 30% currently stated in the permit. Likewise, shutdown is defined as beginning when the load drops below 120 MW and ending when fuel is no longer fed to the unit. A review of CEMS data shows that setting 120 MW as the threshold between startup/shutdown and base load, a value equal to 44% of full load adequately takes into account the emission control reaction time and startup operating condition progression. Note, that redefining this threshold as 120 MW would not affect the time limit of 4 hours for a planned startup and 2 hours for a planned shutdown established in Special Condition 28 nor would it cause the value limits set in the MAERT to be exceeded.

Some of the site wide maintenance activities BEPC is requesting authorization for can be characterized as inherently low emitting (ILE) activities. These ILE activities and operations will be included in the permit under attachment A. A new EPN is will also be added to the MAERT, this is EPN MSSFUG.

Some MSS- related maintenance activities with emissions that are too large to be considered ILE will also be considered in the amendment application. BEPC states that the emissions from these activities will not exceed emission limits now established under the current permit. No separate emission allowables for these activities are being proposed. Such activities include, but are not limited to, online turbine optimization activities and online SCR system maintenance.

Pollution Prevention, Sources, Controls and BACT- [30 TAC 116.111(a)(2)(C)]

Emission sources are the turbine exhaust stacks and fugitive emissions associated with planned MSS. Controls consist of low sulfur fuels for SO_2, combustor design for CO, dry low NO_x combustors for NO_x and an aqueous ammonia-based selective catalytic reduction system. The CEMS will give a direct report of NO_X and CO concentrations. During planned MSS when control devices or process equipment are operating outside the design optimal mode and it is technically infeasible to meet the primary BACT emission rates, secondary BACT limits are necessary. These secondary BACT limits are designed to limit emissions during planned MSS activities. Secondary BACT limits are identified in Special Condition Nos. 25 thru 30. These limitations include work practices limiting the duration of startup and shutdown for combustion equipment, minimizes the amount of time combustion equipment is outside the optimal performance mode (in which the process units and controls were designed to work most effectively). The specific maintenance activities identified in the application have been listed as ILE activities in Attachment A of the permit.

Impacts Evaluation - 30 TAC 116.111(a)(2)(J)

Was modeling conducted?	Yes	Type of Modeling:	Screen3
Will GLC of any air contaminant cause violation of NAAQS?		No	
Is this a sensitive location with respect to nuisance?		No	
[§116.111(a)(2)(A)(ii)] Is the site within 3000 feet of any school?		No	
Additional site/land use information: Land surrounding the facility is mainly undeveloped with industrial facilities to the north of the facilities. The nearest residence is less than 1 mile to the north west of the facility.			

Summary of Modeling Results

Emissions from NO_x were modeled using all NO_x sources on site plus background concentrations. The concentrations from the site were predicted to be 148.5 $\mu g/m^3$ and the background was 39.25 $\mu g/m^3$. When added together, the total concentration was below the NAAQS of 188 $\mu g/m^3$. Modeled concentrations of all other pollutants (CO, PM_{10}, $PM_{2.5}$, and NH_3) for the project only fell below the SIL and/or ESL. Therefore emissions from the facility are not expected to have an adverse impact on health or the environment. No further modeling required.

Pollutant	Averaging	Predicted Concentration	SIL	SIL	Background	Total Conc	NAAQS	NAAQS

	Time	(μg/m³)	(μg/m³)		(μg/m³)	(μg/m³)	(μg/m³)	
NO_x	1-hr	148.5	7.5	No	39.25	187.75	188	Yes
NO_x	Annual	11.88	1	No	39.25	51.13	100	Yes
CO	1-hr	395.55	500	Yes				
CO	8-hr	276.885	2000	Yes				
PM_{10}	24-hr	0.009	5	Yes				
$PM_{2.5}$	24-hr	0.009	1.2	Yes				
$PM_{2.5}$	Annual	0.0018	0.3	Yes				
		GLC_{max} (μg/m³)	ESL (μg/m³)					
NH_3		0.072	170	Yes				

Permit Concurrence and Related Authorization Actions

Is the applicant in agreement with special conditions?	**Yes**
Company representative(s):	**David Cabe and Mark Pavelka**
Contacted Via:	**Email**
Date of contact:	**October 17, 2011**
Other permit(s) or permits by rule affected by this action:	**No**
List permit and/or PBR number(s) and actions required or taken:	**N/A**

Project Reviewer	Date	Team Leader/Section Manager/Backup	Date

Headers

Permit Amendment

Source Analysis & Technical Review

Permit No. 25384 Regulated Entity No. RN100223312

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Footers

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Attachment I

List of Equipment for which BEPC Claims a Positive Use Determination

Brazos Electric Power Coopertive, Inc.
Job Closings
Job No. 505 - 515 Johnson County Plt. Rebuild
Energized Date 9/15/2006

Subledger Description	Doc. Type	Explanation/Vendor Name	Amount
Labor-Direc	JY	BEPC Direct Labor	0.00
Misc	OV	Miscellaneous	578,847.84
Meals & Lod	PV	BEPC Meals and Lodging	6645.74
Transportat	PV	BEPC Transportation	4911.88
Misc Suppli	JE	BEPC Miscellaneous Supplies	-114,663.90
Equipment C	PV	Construction Equipment	101,107.89
Rentals	JE	Rental Equipment	206,448.43
Contractors	JE/JJ	Contractor Cost	27,678,663.34
Legal	PV	Legal work	170,786.28
OH-Misc Adm	PV	Overheads & Miscellaneous Admin	1857.03
		Total:	**28,634,604.53**

Attachment J

BEPC's Discussion regarding Partial Use Calculations

The calculation provided as part of TCEQ's Cost Analysis Procedure ("CAP") is designed for a situation in which add-on pollution control equipment is being utilized to reduce emissions from a facility. It is not suited for equipment that represents a system design change, such as a HRSG, where the pollution control is derived from pollution prevention attributed to an improvement in the equipment's efficiency. The Executive Director's staff has introduced further hurdles to obtaining a positive use determination by mandating the use of some specific inputs for the CAP's variables, such that it is not believed that there are any circumstances under which a positive use determination can be made if one is required to utilize these inputs. This result is contrary to the Legislature's enactment of Tex. Tax Code § 11.31(b).

Specifically, the Executive Director's staff's interpretation of the CAP calculation does not make sense for the following reasons:

(1) The Executive Director's staff has directed the HRSG Applicants to calculate the Production Capacity Factor ("PCF") "by dividing the capacity of the existing equipment or process by the capacity of the new equipment or process." This calculation accurately reflects the first portion of the TCEQ's rules, found in 30 TAC § 17.17(b). However, the Executive Director's staff failed to note that the rule has specifically recognized that the PCF is to be included in the CAP formula only in limited circumstances. The rule notes, "when there is an increase in production capacity, PCF is used to adjust the capacity of the new equipment or process to the capacity of the existing equipment or process. When there is a decrease in production capacity. PCF is used to adjust the capacity of the existing equipment or process to the production capacity of the new equipment or process. In this case, this calculation is modified so that PCF is applied to Capital Cost Old (CCO) rather than Capital Cost New." *Id.*

The Executive Director's staff's direction to the HRSG Applicants, in this regard, is inconsistent with the rule. First, there is no existing equipment or process. As a result. there is no increase or decrease in capacity. Under such circumstances, the rule recognizes that no calculation of PCF should be made. As a result, that portion of the CAP calculation is to be omitted.

(2) Inserting a value in for CCO requires that there be "old equipment." As stated, this is not a replacement of an HRSG. There is no old equipment.[4]

(3) The Executive Director's staff has directed the HRSG Applicants to calculate Capital Cost Old as "the cost of a boiler(s) required to the (sic) produce same amount of steam produced by the HRSGs." The Executive Director's staff's interpretation of CCO is contrary to TCEQ's rules, which define "Capital cost old" as "The cost of the equipment that is being or has been replaced by the equipment covered in an application." 30 TAC § 17.2(2). The definition

[4] The equipment at the Johnson facility was new construction following an explosion and fire that years past had destroyed the prior facility, which included a HRSG. That HRSG caused the explosion and fire and was destroyed in the incident, rendering it useless and of no value.

continues by directing that the calculation of this variable in the CAP procedure is to be performed using one of the four hierarchical methods set forth in 30 TAC § 17.17(b)(1).[5]

The hierarchical methods, with an analysis of their applicability, are as follows:

Method 3.1: If comparable equipment without the pollution control feature is on the market in the United States, then an average market price of the most recent generation of technology must be used.

Analysis: There is no equipment that serves the function of the HRSG without its pollution control feature. The HRSG is the equipment that is the subject of the use determination application. There is no substitute for this equipment. Method 3.1 is therefore inapplicable.[6]

Method 3.2: If the conditions in variable 3.1 do not apply and the company is replacing an existing unit that already has received a positive use determination, the company shall use the CCO from the previous use determination.

Analysis: The company is not replacing an existing unit that already has received a positive use determination. Method 3.2 is therefore inapplicable.

Method 3.3: If the conditions in variable 3.1 and 3.2 do not apply and the company is replacing an existing unit, then the company shall convert the original cost of the unit to today's dollars by using a published industry specific standard. If the production capacity of the new equipment or process is lower than the production capacity of the old equipment or process CCO is divided by the PCF to adjust CCO to reflect the same capacity as CCN.

Analysis: The company is not replacing an existing unit. Method 3.3 is therefore inapplicable.

Method 3.4: If the conditions in variables 3.1. 3.2 and 3.3 do not apply, and the company can obtain an estimate of the cost to manufacture the alternative equipment without the pollution control feature, then an average estimated cost to manufacture the unit must be used. The comparable unit must be the most recent generation of technology. A copy of the estimate must be provided with the worksheet including the specific source of the information.

Analysis: There is no alternative equipment that could be manufactured to serve the function of the HRSG without its pollution control feature. The HRSG is the equipment that is the subject of the use determination application. There is no substitute for this equipment. Method 3.4 is therefore inapplicable.

As applied, TCEQ hierarchical methods are not applicable. Therefore, for purposes of this Application and its CAP calculation, CCO is zero.

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[5] It appears that this reference should be to 30 TAC § 17.17(c)(1).

[6] For purposes of facilitating a timely resolution of this matter, and without waiving its rights to pursue a partial use determination of 64.29%, BEPC is submitting alternatives for the Executive Director's consideration. One of these alternatives is the treatment of the HRSG as the "replacement" for piping necessary to fill the gap that would otherwise exist between pieces of equipment if one were to remove the HRSG and its dedicated ancillary equipment.

(4) TCEQ's rules additionally define CCO in the CAP formula set forth in 30 TAC 17.17(c), stating, "Capital Cost Old is the cost of comparable equipment or process without the pollution control." *See* Figure: 30 TAC § 17.17(c)(1). First, this definition is inconsistent with the TCEQ's earlier definition of the same term, as set forth in 30 TAC § 17.2(2). Second, the Executive Director's staff's interpretation of this element of the formula disregards the fact, as stated above, that the subject of the application is a HRSG, for which there is no other "comparable equipment or process without the pollution control." There is no other comparable equipment, and thus there can be no value for CCO in the CAP calculation for the HRSG.

(5) As applied, the staff's interpretation of the formula ensures that, under no circumstances, will a HRSG ever be granted a positive use determination. Such an outcome is inconsistent with the Legislature's determination that HRSG constitutes pollution control equipment, and is therefore invalid, improper and illegal rulemaking.

(6) Even if one were replacing a HRSG, CCO does not make sense. As previously utilized, CCO was designed to identify the portion of the new equipment that was an environmental improvement on the old equipment's design. Pulling out the CCO from the CCN isolated the environmentally beneficial equipment that was eligible for a tax exemption. This conclusion is supported by the TCEQ's treatment of certain equipment referenced in the introductory language under the Tier I Table of 30 TAC 17.14(a), which states. "For items where the description limits the use determination to the incremental cost difference, the cost of the property or device with the pollution control feature is compared to a similar device or property without the pollution control feature." BEPC, through its Application, is not presenting a situation for which an environmental element must be isolated. The formula works solely when an entity is replacing in-kind, like equipment, with updated equipment that has an additional pollution control feature. The consideration of CCO in such a circumstances allows the entity to isolate the value of that environmental feature. In the case of the HRSG, the use of the CCO, as interpreted by the Executive Director's staff, simply makes the HRSG twice as expensive - first, the entity must purchase the HRSG, then it must discount the value of the HRSG by the cost of hypothetical equipment designed to mimic the productivity of the HRSG itself. Such an approach negates the purpose of installing the HRSG in the first place - producing greater quantities of steam while reducing the environmental impact that would occur without the use of this equipment.

(7) If one does use a CCO, as defined by the Executive Director's staff for the first time in the NOD, based on the cost of a boiler(s) required to produce the same amount of steam produced by the HRSG, there is no basis for discounting that result to account for the income stream associated with the additional steam produced by the HRSG. NPVMP is designed to capture "the production benefits of property used partially for pollution control and partially for production." *See* 35 Tex. Reg. 10964, 10965 (Dec 10, 2010). Because the CCO and CCN have been equalized or normalized, the HRSG is no longer producing additional steam beyond that produced by CCO. Therefore, there is no basis for NPVMP under such circumstances.

(8) TCEQ's rules define "Production Cost" as "The costs directly attributed to the production of the product, including raw materials, storage, transportation, and personnel, but excluding non-cash costs, such as overhead and depreciation." 30 TAC § 17.17(c)(2). Through its NOD, the staff narrows the scope of Production Cost by asserting that the cost attributed to the production of electricity, which the staff has designated as the marketable product, must "exclude costs relating to operating the gas turbine, associated duct burners, or the steam turbine including fuel costs." Attachment A, p. 3. Without the operation of these units, and their associated expenses (including fuel costs), no electricity would be generated from any steam

produced via the HRSG, and therefore no marketable product would be generated. The staff cannot have it both ways. If electricity is the marketable product, the HRSG Applicants must be allowed to take into account the costs associated with generating that marketable product as part of its NPVMP calculation. TCEQ's rules mandate it.

(9) The exclusion of fuel costs from Production Cost is particularly problematic and inappropriate. "Production Cost" expressly includes the cost of "raw materials." *See* 30 TAC § 17.17(c)(2). In this context, fuel is the raw material for the production of the steam and its costs are an element of Production Cost, by definition. Additional costs that are included in Production Cost include storage, transportation, and personnel costs. *See id.* The staff's interpretation of the elements to be included in, and excluded from, the calculation of NPVMP is inaccurate and constitutes improper and illegal rulemaking.

(10) In addition, it should be noted that local appraisal districts in Texas have the authority to use and are legally required to at least consider application of the income approach when appraising plants like BEPC's. *See, e.g.*, TEX. TAX CODE §§ 23.01(b), 23.0101. The income approach is specifically grounded upon a consideration of overall plant revenues,[7] which would include revenues associated with the production of electricity by and through BEPC's steam turbines, and revenues, if any, from the HRSG's steam itself. Accordingly, the deduction of any NPVMP in the CAP calculation would cause an inappropriate and unjust "double counting" of those revenues and, as far as ad valorem taxation goes, effectively cause BEPC to pay a "double tax" on those revenues.

Specifically, through its proposed calculation of NPVMP, the staff reduces the amount of exemption authorized for a HRSG to account for the steam's income stream. Then, the appraisal district is authorized to appraise the entity on that same income stream, under an income-based approach. In fact, under the staff's approach, the value of the steam is essentially taxed or appraised three times. First, the CCO costs are inflated to normalize the steam production of the hypothetical CCO and that of the CCN. Second, this result is discounted by the value of the steam's income stream. Finally, the tax appraisal district can appraise the steam's income stream. Two discounts of the potential tax exemption based on the value of the steam, and an appraisal of the steam itself, is two too much. TCEQ should leave the consideration of any income stream arising from the use of the HRSG to the governmental entity best able to determine its value – the appraisal district.

(11) The application of the Executive Director's staff interpretation of the CAP formula TCEQ's formula consistently results in a negative partial use calculation. HRSGs have been statutorily designated as pollution control equipment. As such, some portion of the value of that equipment must be attributed to pollution control, and provided a tax exemption. A result of zero or something less than zero is not valid, any more than a result of greater than 100% is valid. Because the formula is capable of generating a naught or a negative number, it is inconsistent with state law, and invalid as a matter of law.

(12) Ironically, the more efficiently a power plant with a HRSG operates, the lower is the result of the formula. A power plant that operates more efficiently will produce more steam, which will generate a higher income stream under the CAP formula. Because the income stream is then used to reduce the potential positive use determination, the formula actually provides an incentive for power plants to operate less efficiently, so as to obtain a higher tax

[7] *See* TEX. TAX CODE § 23.012.

exemption. This is counter to the purpose for the constitutional amendment and the statute that established the tax exemption.

For all of these reasons. the CAP formula and the Executive Director's staff's interpretation thereof, is invalid, indeed illegal, as applied to the HRSG applicants. The Executive Director's staff has so modified the interpretation of its rule as to ensure its inconsistency with the statute pursuant to which it was promulgated. In doing so, the Executive Director's staff has engaged in improper and illegal rulemaking, the elements of which are as follows:

(a) Requiring the calculation of a Production Capacity Factor premised on the presence of existing equipment which, in fact, does not exist. Doing so in a straight-forward manner results in a calculation of zero (No old equipment capacity / HRSG capacity: 0 x X = 0). This calculation ensures a negative use determination for a HRSG and such a result is contrary to the statutory intent of TEX. TAX CODE § 11.31;

(b) Incorporating a value for Capital Cost Old which is entirely hypothetical and without any basis in law. For the HRSG applications, there is no old equipment and as stated in Item 2 above, were there such, the purpose for subtracting out such value is not present in the case of the installation of a HRSG:

(c) Requiring HRSG applicants to engage in a fictional consideration of the cost of a boiler(s) that would be necessary should the applicants have desired to produce the same amount of steam without the usage of a HRSG;

(d) Requiring HRSG applicants to deduct the value of the steam's income stream after requiring the applicants to equalize or normalize the production capacity of the HRSG with that of a boiler(s) that would be necessary should the applicants have desired to produce the same amount of steam without the usage of a HRSG;

(e) Dictating that the marketable product generated by the HRSG is electricity, although the HRSG produces no electricity. The Executive Director's staff's interpretation runs directly counter to its definition of "marketable product" as set forth in Figure: 30 TAC § 17.17(c)(2), note i;

(f) Excluding from its calculation of Production Cost the cost of fuel to operate the gas turbine, which generates the heat necessary to operate the HRSG: and

(g) Through the sum of these actions, ensuring in each and every instance a negative use determination for a HRSG, such result being contrary to the statutory intent of TEX. TAX CODE § 11.31.

Attachment K

BEPC's Partial Use Calculation Utilizing the Executive Director's Staff's Mandated Inputs into CAP Calculation Variables

Attachment K - Use Determination Utilizing TCEQ Assumptions to Which BEPC Objects

TCEQ Use Determin \pplication Section 11 use:
Company: Brazi ic Power Cooperative, Inc.
Plant: Johnso ounty Generation Facility
Unit: 258 MW 1 x 1 Configuration Combined Cycle Power Plant (1996)
Address: Cleburne, Texas
Project: Tier III Cost Analysis Procedure
Date: 10-Feb-12

I. Assumptions

HRSG Only

Pollution Control Property (PC)		Source
Property Cost:	$28,111,986.00	BEC Acctng
Capital Cost ($/KW):	$326.88	PC/TC
Total Capacity (MW):	258	∑(CT+ST)
CT Capacity (MW)	172	BEC 2010 RUS Form 12
ST Capacity (MW)	86	BEC 2010 RUS Form 12
2010 Net Annual ST Generation Capacity (KWhr):	487,215,000	BEC 2010 RUS Form 12
2010 Net Annual ST Generation Capacity (MWhr):	487,215	BEC 2010 RUS Form 12
2010 ST Capacity Factor:	64.67	Energy/(TC * 8760)
2010 Plant Heat Rate (btu/kwhr):	7,782	BEC 2010 RUS Form 12
2010 Plant Heat Rate (mmbtu/kwhr):	0.008	NPHR/1E06
2010 Operating Hours	7,606	BEC 2010 RUS Form 12
Capital Cost Old:	41,280,000	
Comparable Technology Cost:	0	
Comparable Technology:	0	
Design Capacity Factor:	0	
Capacity (MW):	1	

Conversion Factors	
Hrs/yr	8760
KW/MW	1000
lb/kg	2.2
s/hr	3600
btu/mmbtu	1000000

Economic Assumptions		Source
Discount Rate (%)	10.00%	Standard project rate
Periods (Yrs)	30	RUS depreciation
PC Property Fixed O&M Cost ($/KW-yr)	$6,126,060	BEC 2010 RUS Form 12
CT Fixed O&M Costs ($)	$4,084,040	Formula
ST Fixed O&M Costs ($)	$2,042,020	Formula
Fuel Cost ($/MMBTU)	$0.00	Note 1
PC property Variable Cost ($/MWh)	$5.00	Check with OSE
PC property Variable Cost ($/KWh)	$0.0050	Formula
ERCOT Electricity Pricing ($/MWh)	$44.48	Note 2
Interest Rate (%)	10.00%	

Note 1: Average cost for fuel (2009 - 2011) weighted by monthly steam turbine generation

Note 2: Average Settlement Point price for resource weighted by hourly steam turbine generation, reflected by North Load Zone Market Clearing Price for Energy (MCPE) for Jan 1, 2009 - Nov 30, 2010 and Real-time Resource Settlement

Levelized Cost of Energy (LCOE) Model Outputs	
Capitol Recovery Factor (%)	10.61%
LCOE ($/KWh)	0.03079

II. Cost Analysis Procedure

A. $$\frac{[(\text{Production Capacity Factor} \times \text{Capital Cost New}) - \text{Capital Cost Old} - \text{Marketable Product}]}{\text{Capital Cost New}}$$

B. Cost Analysis Procedure Formulas (TCEQ)

Partial Use Determination

$$\frac{[(\text{Production Capacity Factor} \times \text{Capital Cost New}) - \text{Capital Cost Old} - \text{Marketable Product Value}]}{\text{Capital Cost New}}$$

where: Marketable Product Value = $\sum_{t=1}^{n} \frac{\text{Marketable Product Value - Production Cost}}{(1 + \text{Interest Rate})^n}$

n = estimated useful life in years of years equipment
t = year one
Interest Rate = 10%

C. Cost Analysis Procedure for Pollution Control Property

Marketable Product Value = Electricity Price ($/MWh) x MWh per Year
Direct Cost of Production = Levelized Cost of Energy x KWh per Year

$$\text{LCOE ($/KWh)} = \frac{(\text{Capital Cost} \times \text{Capital Recovery Factor}) + \text{Fixed O\&M Costs}}{\text{Hours per Year} \times \text{Capcity Factor}} + (\text{Fuel Cost} \times \text{Heat Rate})$$

Capital Recovery Factor (CRF) $\frac{i \times (1 + i)^n}{(1+i)^n - 1}$

(PC)	(CRF)		(Annual cost to carry)		(FOM)	(Total Annual FC)	
$28,111,986.00	10.61%	=	$2,982,098.34	+	$2,042,020	$5,024,118.34	
						$0.0103	/kWh
					(Fuel x NPHR)	$0.0000	
					LCOE:	$0.01031	($/kWh)

Attachment K, cont'

III. Cost Analysis Pr[illegible]e Calculations For Johnson County HRSG

For[illegible]: $\frac{(PCF \times CCN) - CCO - NPVMP}{CCN}$

A. Marketable Prod[illegible]alue (MPV)

Electricity Price $\frac{\$}{MWh}$ x $\frac{\text{Plant MWh}}{\text{Year}}$ = ($) MPV

$44.48 x 487,215 = $21,671,323.20

B. Production Cost (PC)

Levelized Cost Of Energy (LCOE) $\frac{\$}{KWh}$ x $\frac{\text{Plant MWh}}{\text{Year}}$ = ($) PC

$0.01031 x 487,215,000 = $5,024,118.34

Net Present Value Marketable Product (NPVMP) Calculation

$\sum_{t=1}^{n}$ $\frac{\text{Marketable Product Value - Production Cost}}{(1 + \text{Interest Rate})^n}$ = NPVMP ($)

NPVMP

$\sum_{t=1}^{n}$ $\frac{\$21,671,323.20 - \$5,024,118.34}{1.10}$ = $156,931,776.31

$156,931,776.31

If MP is <= 0, then MP = 0

C. Production Capacity Factor (PCF)

$\frac{\text{Production Capacity of Existing Equipment or Process}}{\text{Production Capacity of New Equipment or Process}}$ = PCF

$\frac{0}{86 \text{ MW} \times 56.21\%}$ = PCF 1.00

D. Bapital Cost New (CCN)

Pollution Control Property (PC) = CCN $28,111,986.00

E. Capital Cost Old (CCO)

Comparable Technology = CCO $41,280,000.00

Partial Use Determination Calculation

$\frac{(PCF \times CCN) - CCO - MP}{CCN}$ = Partial Use Determination %

$\frac{\$28,111,986.00 - \$41,280,000.00 - \$156,931,776.31}{\$28,111,986.00}$ = -605.08%

TCEQ Use Determination Application Section 11 use:	
Use Percent	-605.08%
Estimated Dollar Value	-$170,099,790.31

Eligible HRSG Costs (Partial Use Determination % x PC Property) = -$170,099,790.31

$16,647,204.86
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Attachment L

BEPC's Partial Use Calculation Utilizing an
Avoided NOx Emissions Approach

Brazos Tier III - Avoided NOx Emissions

Input	Brazos Details	Data Source	Baseline Details	Data Source
Configuration	Combined Cycle		Simple Cycle	
Avg Heat Rate (Btu/kWh)	7,782	2010 capacity test	10,870	2010 operation data
NOx Emissions (tpy)	164.5	2011		
Plant Capacity (MW)	258	Design data		
Capacity Factor	74.48%	2010		
Total Gateway Facility Cost	33,179,824.84	2010		

STEP 1
CT/HRSG Output-Based Emissions Calculation (lbs NOx/MWh)

Input-based Emissions (lbs NOx/MMBtu)	x	Heat Rate (Btu/kWh)	/	Unit Conversions (1,000,000 Btu/1,000 kWh)	=	Output-based Emissions (lbs NOx/MWh)
0.0140		7,782		1,000		0.1089

STEP 2
CT/HRSG Output Conversion Calculation (tons NOx/yr)

Output-based Emissions (lbs NOx/MWh)	x	Capacity (MW)	x	Capacity Factor (%)	x	Unit Conversions (24 hrs/day x 365 days/yr /2,000 lbs/ton)	=	Emissions (tons/yr)
0.1089		258		74.48%		4.38		91.7

STEP 3
CT only Output-Based Emissions Calculation (lbs NOx/MWh)

Input-based Emissions (lbs NOx/MMBtu)	x	Heat Rate (Btu/kWh)	/	Unit Conversions (1,000,000 Btu/1,000 kWh)	=	Output-based Emissions (lbs NOx/MWh)
0.0140		10,870		1,000		0.1522

STEP 4
CT only Output Conversion Calculation (tons NOx/yr)

Output-based Emissions (lbs NOx/MWh)	x	Capacity (MW)	x	Capacity Factor (%)	x	Unit Conversions (24 hrs/day x 365 days/yr /2,000 lbs/ton)	=	Emissions (tons/yr)
0.1522		258		74.48%		4.38		128.1

STEP 5
Percent NOx Reduction Calculation

Baseline Emissions (tons/yr)	-	Gateway Emissions (tons/yr)	/	Gateway Emissions (tons/yr)	=	NOx Reduction (%)
128.1		91.7		91.7		39.7%

Attachment M

BEPC's Partial Use Calculation Utilizing
the HRSG as the Replacement for Piping,
with the Cost of the Piping as CCO

Attachment M, With Piping as Assumed "Replaced Equipment" and its Cost as CCO

TCEQ Use Determi: Application Section 11 use:
Company: Bra: .tric Power Cooperative, Inc.
Plant: Johnson County Generation Facility
Unit: 258 MW 1 x 1 Configuration Combined Cycle Power Plant (1996)
Address: Cleburne, Texas
Project: Tier III Cost Analysis Procedure
Date: 10-Feb-12

I. Assumptions

Pollution Control Property (PC)		Source
Property Cost:	$28,111,986.00	BEC Acctng
Capital Cost ($/KW):	$326.88	PC/TC
Total Capacity (MW):	258	∑(CT+ST)
CT Capacity (MW)	172	BEC 2010 RUS Form 12
ST Capacity (MW)	86	BEC 2010 RUS Form 12
2010 Net Annual ST Generation Capacity (KWhr):	487,215,000	BEC 2010 RUS Form 12
2010 Net Annual ST Generation Capacity (MWhr):	487,215	BEC 2010 RUS Form 12
2010 ST Capacity Factor:	64.67	Energy/(TC * 8760)
2010 Plant Heat Rate (btu/kwhr):	7,782	BEC 2010 RUS Form 12
2010 Plant Heat Rate (mmbtu/kwhr):	0.008	NPHR/1E06
2010 Operating Hours	7,606	BEC 2010 RUS Form 12
Capital Cost Old:	0	
Comparable Technology Cost:	0	
Comparable Technology:	0	
Design Capacity Factor:	0	
Capacity (MW):	1	

Conversion Factors	
Hrs/yr	8760
KW/MW	1000
lb/kg	2.2
s/hr	3600
btu/mmbtu	1000000

Economic Assumptions		Source
Discount Rate (%)	10.00%	Standard project rate
Periods (Yrs)	30	RUS depreciation
PC Property Fixed O&M Cost ($/KW-yr)	$6,126,060	BEC 2010 RUS Form 12
CT Fixed O&M Costs ($)	$4,084,040	Formula
ST Fixed O&M Costs ($)	$2,042,020	Formula
Fuel Cost ($/MMBTU)	$4.11	Note 1
PC property Variable Cost ($/MWh)	$5.00	Check with QSE
PC property Variable Cost ($/KWh)	$0.0050	Formula
ERCOT Electricity Pricing ($/MWh)	$44.48	Note 2
Interest Rate (%)	10.00%	

Note 1: Average cost for fuel (2009 - 2011) weighted by monthly steam turbine generation
Note 2: Average Settlement Point price for resource weighted by hourly steam turbine generation, reflected by North Load Zone Market Clearing Price for Energy (MCPE) for Jan 1, 2009 - Nov 30, 2010 and Real-time

Levelized Cost of Energy (LCOE) Model Outputs	
Capitol Recovery Factor (%)	10.61%
LCOE ($/KWh)	0.03079

II. Cost Analysis Procedure

A. $$\frac{[(\text{Production Capacity Factor x Capital Cost New}) - \text{Capital Cost Old} - \text{Marketable Product}]}{\text{Capital Cost New}}$$

B. Cost Analysis Procedure Formulas (TCEQ)

Partial Use Determination

$$\frac{[(\text{Production Capacity Factor x Capital Cost New}) - \text{Capital Cost Old} - \text{Marketable Product Value}]}{\text{Capital Cost New}}$$

where: Marketable Product Value = $\sum_{t=1}^{n} \frac{\text{Marketable Product Value - Production Cost}}{(1 + \text{Interest Rate})^n}$

n = estimated useful life in years of years equipment
t = year one
Interest Rate = 10%

C. Cost Analysis Procedure for Pollution Control Property

Marketable Product Value = Electricity Price ($/MWh) x MWh per Year
Direct Cost of Production = Levelized Cost of Energy x KWh per Year

$$\text{LCOE ($/KWh)} = \frac{(\text{Capital Cost x Capital Recovery Factor}) + \text{Fixed O\&M Costs}}{\text{Hours per Year x Capcity Factor}} + (\text{Fuel Cost x Heat Rate})$$

Capital Recovery Factor (CRF) $\frac{i \times (1+i)^n}{(1+i)^n - 1}$

(PC)	(CRF)		(Annual cost to carry)		(FOM)	(Total Annual FC)	
$28,111,986.00	10.61%	=	$2,982,098.34	+	$2,042,020	$5,024,118.34	
						$0.0103	/kWh
					(Fuel x NPHR)	$0.0320	
					LCOE:	**$0.04229**	($/kWh)

Attachment M, cont'

III. Cost Analysis F ire Calculations For Johnson County HRSG

mula: $\frac{(PCF \times CCN) - CCO - NPVMP}{CCN}$

A. Marketable Product Value (MPV)

Electricity Price $\frac{\$}{MWh} \times \frac{\text{Plant MWh}}{\text{Year}}$ = ($) MPV

$44.48 x 487,215 = $21,671,323.20

B. Production Cost (PC)

Levelized Cost Of Energy (LCOE) $\frac{\$}{KWh} \times \frac{\text{Plant MWh}}{\text{Year}}$ = ($) PC

$0.04229 x 487,215,000 = $20,606,531.81

Net Present Value Marketable Product (NPVMP) Calculation

$$\sum_{t=1}^{n} \frac{\text{Marketable Product Value - Production Cost}}{(1 + \text{Interest Rate})^n} = \text{NPVMP ($)}$$

$$\sum_{t=1}^{n} \frac{\$21{,}671{,}323.20 - \$20{,}606{,}531.81}{1.10} = \text{NPVMP } \$10{,}037{,}697.34$$

If MP is <= 0, then MP = 0

C. Production Capacity Factor (PCF)

$\frac{\text{Production Capacity of Existing Equipment or Process}}{\text{Production Capacity of New Equipment or Process}}$ = PCF

$\frac{0}{86 \text{ MW} \times 56.21\%}$ = PCF 1.00

D. Capital Cost New (CCN)

Pollution Control Property (PC) = CCN $28,111,986.00

E. Capital Cost Old (CCO)

Comparable Technology = CCO $150,000.00

Partial Use Determination Calculation

$$\frac{(PCF \times CCN) - CCO - MP}{CCN} = \text{Partial Use Determination \%}$$

$$\frac{\$28{,}111{,}986.00 - \$150{,}000.00 - \$10{,}037{,}697.34}{\$28{,}111{,}986.00} = 63.76\%$$

TCEQ Use Determination Application Section 11 Use	
Use Percent	63.76%
Estimated Dollar Value	$17,924,288.66

Eligible HRSG Costs
(Partial Use Determination % x PC Property) = $17,924,288.66

Bryan W. Shaw, Ph.D., P.E., *Chairman*
Toby Baker, *Commissioner*
Zak Covar, *Commissioner*
Richard A. Hyde, P.E., *Executive Director*

Rec'd 2-6-14

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

February 3, 2014

Mr. Jim Harris
Agent
H & H Associates
406 FM 3016
Grapeland, Texas 75844

Re: Notice of Technical Deficiency
Brazos Electric Power Cooperative, Inc.
Johnson County Generation Facility
Cleburne (Johnson County)
Regulated Entity Number: RN100221985
Customer Reference Number: CN600128821
Application Number: 13544

Dear Mr. Harris:

This letter responds to Brazos Electric Power Cooperative, Inc.'s Application for Use Determination, received April 27, 2009 pursuant to the Texas Commission on Environmental Quality's (TCEQ) Tax Relief for Pollution Control Property Program for the Johnson County Generation Facility.

The TCEQ has conducted further technical review and determined that additional information required by Title 30 Texas Administrative Code (TAC) §17.10 is warranted for application #13544.

The Executive Director interprets Texas Tax Code (TTC) §§11.31(k) and (m) as establishing an expedited review process and exempting an applicant from providing detailed information regarding the anticipated environmental benefit for property on the k-list. Because Article VIII, Section 1-l, of the state constitution authorizes the exemption only for property used to meet or exceed an environmental rule, the Executive Director does not interpret TTC §11.31 subsection (m) as exempting §11.31(k)-listed property from the TCEQ's review standards at Title 30 Texas Administrative Code (TAC) Chapter 17 or mandating the issuance of a positive use determination, when the property is not used, constructed, acquired, or installed to meet or exceed an environmental rule.

Please revise your application to include the following information.

Issue 1 – Review of Environmental Rule Citations

In review of the facility's air permits and associated filings, the following comments on rule citations are in part based on representations made in the permit documents. It does not appear that sufficient information has been provided to establish a clear connection

between the listed equipment and the cited rules. For each cited rule, please provide an explanation of how the equipment is used to meet a requirement in the rule.

New Source Performance Standard (NSPS) Subpart Da is a standard of performance for electric utility steam generating units, i.e., the HRSG, and provides emission limits for nitrogen oxides (NOx), particulate matter, and sulfur dioxide. Given that Da only applies to the HRSG itself, it does not appear that use of the HRSG is required to meet Da or that it helps the facility meet the emission limit for the HRSG itself. The absence of a HRSG (that is subject to regulation under Da) would not affect emission limitations of other sources at the plant, e.g., the gas turbine (regulated under GG). Please explain in detail how a HRSG is used to meet the requirements of Da.

Regarding the Clean Air Interstate Rule (CAIR), CAIR is a cap and trade program that allocates allowances to all electric generating units. Please explain how a Heat Recovery Steam Generator (HRSG) is required to meet a CAIR requirement.

Title 40 CFR §52.21(b)(49)(v) states, "Beginning July 1, 2011, in addition to the provisions in paragraph (b)(49)(iv) of this section, the pollutant greenhouse gases (GHGs) shall also be subject to regulation (a) at a new stationary source that will emit or have the potential to emit 100,000 tpy carbon dioxide equivalent (CO_2e); or (b) At an existing stationary source that emits or has the potential to emit 100,000 tpy CO_2e, when such stationary source undertakes a physical change or change in the method of operation that will result in an emissions increase of 75,000 tpy CO_2e or more." The Johnson County Generation Facility was authorized by construction air permit 25384 which was issued December 6, 1994. The air permit general conditions required that construction be started no more than 18 months after permit issuance. Therefore, criterion (a) above does not apply. There is no documentation that the site has undergone a modification which would trigger criterion (b) above. Similarly, the application has not demonstrated that the site has gone through a major modification which would trigger a control technology review as described in 40 CFR §52.21(j). An applicant cannot claim eligibility for a positive use determination based on exceeding a rule that the applicant is not required to meet.

Best Available Control Technology (BACT) analysis is completed in conjunction with construction and amendment air permit applications. Documentation pertaining to air permit 25384 has been reviewed. We found no representations of HRSGs providing pollution control. Agency approved BACT for control of nitrogen oxides (NO_x) was selective catalytic reduction (SCR).

Attachment B to your June 24, 2013 response includes, "However, as a permit application's representations are considered conditions upon which the permit is issued, and are enforceable as such, BEPC is entitled to rely on these representations for purposes of establishing that the HRSG constitutes BACT for the Plant. . ." It is correct that permit application representations are considered conditions upon which issuance of the permit is predicated. However, air permit applications contain many representations and not all such representations are related to BACT.

42 U.S.C. §7401(c) states, "A primary goal of this chapter is to encourage or otherwise promote reasonable Federal, State, and local governmental actions, consistent with the provisions of this chapter, for pollution prevention." This does not compel an applicant to install a HRSG.

30 TAC §§117.450, 117.454, 117.456 and 117.9030 apply to major sources within the Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area. More appropriate citations would pertain to Utility Electric Generation Sources within the Dallas-Fort Worth Eight-Hour

Ozone Nonattainment Area. If you contend that there is an appropriate citation in Chapter 117 that would support use determination application 13544, please provide the specific citation and explain how the application equipment enables the applicant to meet or exceed that rule.

The application cites 40 CFR §§50.11, 50.15, 50.17, 50.6, and 50.8 which are the National Ambient Air Quality Standard (NAAQS) for NO2, O3, SO2, PM10, and CO respectively. States employ state implementation plans and incorporated air permitting programs to ensure continued compliance with the NAAQS in attainment areas and reasonable progress toward attainment in non-attainment areas. NAAQS are ambient air concentrations promulgated by the EPA to protect public health and welfare. The NAAQS is not an emission limit for a particular facility or source of pollution and does not require specific facilities to use any particular pollution controls.

Issue 2 – Calculation of an Appropriate Partial Positive Use Determination

Your response to the February 21, 2013 request for additional information requests a partial positive use determination based on the Cost Analysis Procedure (CAP) located in 30 TAC §17.17. In addition the response provides alternative methodologies for calculating a partial positive use determination. One method proposes using the calculation included in the executive director's December 3, 2008 HRSG appeal brief, another method is based on an Avoided Emissions approach, and a third method is based on using the CAP with various modifications to equation variables.

First we will evaluate the alternative methods. The first proposed methodology is based on a calculation included in the brief filed on December 3, 2008, by the executive director in response to the HRSG appeals. The brief included a proposed partial use determination calculation that was based on increased efficiency. Between the filing of the brief and the February 2009 agenda date the calculation was re-evaluated and determined to not be appropriate since the percentage yielded on a positive use determination increases as the efficiency of the equipment decreases. The executive director does not support the use of this calculation.

The second proposed methodology proposes an Avoided Emissions approach that compares the thermal output of a combined cycle facility and a simple cycle facility. Please correct Step 5 of the calculation. The percentage NOx emissions reduction attributable to the HRSG is more accurately calculated as (Output Baseline – Output Subject)/Output Baseline.

The other methods use the CAP to calculate a proposed use determination percentage. Capital Cost New is defined as the HRSG and dedicated ancillary equipment. Capital Cost Old is defined as the value of "piping necessary to gap created by the absence of the HRSG" and $0. Net Present Value of Marketable Product is defined as either $0 or is calculated using fuel costs as part of Production Costs.

Please provide a listing of the equipment listed as dedicated ancillary equipment. Does this included the steam turbine and associated water systems? If so please remove them from the application. During the 2008 technical review the executive director evaluated steam turbines and determined that they are installed for the sole purpose of producing electricity and not as pollution control equipment. As such, steam turbines are not eligible for a positive use determination. The water systems are considered to be production equipment and the TCEQ has consistently issued negative determinations for this type of equipment.

Piping is used to convey exhaust gases from the combustion chamber to a control device or stack. HRSG's are used to convert energy contained in waste heat into steam. The appropriate comparable equipment for Capital Cost Old (CCO) is a boiler sized to create the same amount of steam as the HRSG. Allowing CCO to be $0 or the value of a piece of pipe would lead to a determination that a piece of production equipment, the HRSG, was installed for the single purpose of preventing pollution rather than for the purpose of producing electricity.

Production Costs are the costs related to operating the equipment for which the positive use determination is being requested. In the request for additional information we stated that Production Costs were to exclude "costs related to operating the gas turbine, associated duct burners, or the steam turbine including fuel costs." The appropriate costs to be included in Production Costs are those costs related to operating the HRSG. We agree that this includes the costs related to the operation of the duct burners including fuel costs. We do not agree that production costs include costs related to operating the gas turbine, the water systems, or the steam turbine.

Please resubmit your application using the CAP with the variables calculated as explained in the February 21, 2013, letter with the exception of additional production costs as explained in the preceding paragraph.

The TCEQ appreciates your response in this matter. The revised application must be submitted by March 21, 2014 to the TCEQ Tax Relief for Pollution Control Property Program, MC-110, P.O. Box 13087, Austin, Texas 78711-3087. Failure to submit a complete application, including the requested information, may result in your application being voided and the associated application fee being forfeited in accordance with 30 TAC §17.20(b).

If you have questions regarding this letter or need further assistance, please contact Ronald Hatlett of the Tax Relief for Pollution Control Property Program by telephone at (512) 239-6348, by e-mail at ronald.hatlett@tceq.texas.gov, or write to the Texas Commission on Environmental Quality, Tax Relief for Pollution Control Property Program, MC-110, P.O. Box 13087, Austin, Texas 78711-3087.

Sincerely,

Chance Goodin, Team Leader
Stationary Source Programs
Air Quality Division

CG/RH

THOMPSON & KNIGHT LLP

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April 4, 2014

Via E-mail and U.S. Mail

Mr. Ronald Hatlett
Texas Commission on Environmental Quality
Tax Relief for Pollution Control Property
Program
P. O. Box 13087, MC-1110
Austin, TX 78711-3087

Re: Brazos Electric Power Cooperative Inc.; Johnson County Generation Facility; Use Determination Application No. 13544; Response to Second Notice of Technical Deficiency

Dear Mr. Hatlett:

On behalf of Brazos Electric Power Cooperative, Inc. ("BEPC"), I am submitting this response to the Notice of Technical Deficiency issued by the Executive Director on February 3, 2014 ("2014 NOTD"), and received by BEPC on February 6, 2014. The Executive Director extended the deadline for the filing of this response to April 4, 2014, and this response is timely filed. A copy of the NOTD is attached hereto as Attachment A. Through the NOTD, the Executive Director requested additional information related to two issues: (i) provision of a "clear connection between the listed equipment and the cited rule;" and (ii) submission of the Cost Analysis Procedure with the variables calculated as explained in the February 21, 2013 Notice of Technical Deficiency ("2013 NOTD") with the exception of additional production costs, as described in the 2014 NOTD. BEPC provides the following response, which is supplemental to its prior submissions to the Executive Director and the Commission pursuant to the 2013 NOTD. This response incorporates these prior submissions herein. BEPC further reserves the right to rely upon the submissions of the other HRSG applicants that have matters pending before the Commission at this time should additional proceedings in this matter occur.

The 2014 NOTD illuminates three fundamental issues that divide the HRSG applicants and the Executive Director, specifically: (i) what applicable law requires of a HRSG applicant; (ii) what information is required for an applicant to support its contention that the HRSG "is used to meet or exceed" an environmental rule; and (iii) what elements must be included in a calculation of the positive use determination percentage. Essential to resolving these issues is a recognition by all involved that HRSGs have been statutorily designated as "pollution control equipment." As such, some portion of the value of the HRSG must necessarily be attributed to pollution control, and provided a tax exemption. The process in which the parties are now engaged is to determine the portion (expressed in percentages) of the HRSG's value is attributable to production and what percentage is attributable to pollution control. The percentages must add up to 100%. To conclude this matter without further proceedings, the

HRSG applicants and the Executive Director will need to agree upon a satisfactory resolution of these issues.

While BEPC is committed to working toward such a resolution, the Executive Director's 2014 NOTD requires that BEPC set forth, once again, its position with respect to these three fundamental issues, or else, as the 2014 NOTD implies, the Executive Director may find that BEPC has failed to submit a complete application and therefore determine that BEPC's application is void.

Texas Tax Code § 11.31(m) Removes Need for Environmental Rule to Be Cited in HRSG Application

As stated in its response to the 2013 NOTD, BEPC objects to the Executive Director's requirement to identify an environmental regulation that is met or exceeded through the use of its HRSG. The Texas Legislature expressed its intent that HRSGs be treated as pollution control "facilities, devices or methods for the control of air, water, or land pollution" when it amended Section 11.31 of the Tax Code in 2007 to include subsection (k). That subsection requires that TCEQ adopt rules establishing a non-exclusive a list of such facilities, devices and methods and mandates that HRSGs be included on that list. *See* TEX. TAX CODE § 11.31(k).

Here, the Legislature deliberately and purposefully included HRSGs in its list of facilities, devices, or methods that "must" be treated as "facilities, devices, or methods for the control of air, water, or land pollution ..." TEX. TAX CODE § 11.31(k). The Legislature did so with full knowledge that HRSGs are devices that are necessarily part of the production process and are commonly used as power plant components. Accordingly, HRSGs must be treated as pollution control facilities, devices or methods, and the Executive Director cannot interpret the statute in a contrary manner to avoid this unambiguous legislative mandate.

Section 11.31(m) states:

> (m) Notwithstanding the other provisions of this section, if the ... facility, device, or method is a ... facility, device, or method ... included on the list adopted under Subsection (k), the executive director ... and *without regard to whether the information required by Subsection (c)(1)*[1] *has been submitted* ... shall determine

[1] Texas Tax Code § 11.31(c) states, "In applying for an exemption under this section, a person seeking the exemption shall present in a permit application or permit exemption request to the executive director of the Texas Natural Resource Conservation Commission information detailing:

(1) the anticipated environmental benefits from the installation of the facility, device, or method for the control of air, water, or land pollution;

(2) the estimated cost of the pollution control facility, device, or method; and

(3) the purpose of the installation of such facility, device, or method, and the proportion of the installation that is pollution control property."

> that the ... facility, device, or method... is used wholly or partly as a ... facility, device, or method ... for the control of air, water, or land pollution and shall take the actions that are required by Subsection (d) in the event such a determination is made.

TEX. TAX CODE § 11.31(m) (emphasis added). This legislative directive is definitive and unambiguous. The list comprises facilities, devices, or methods that the Legislature has conclusively determined meet all criteria to constitute pollution control property. The phrase "notwithstanding the other provisions of this section" clearly and directly contradicts the Executive Director's position that it must independently evaluate and apply criteria found in other parts of Section 11.31 before a positive use finding may be issued.

Further, the Executive Director is to make his determination without regard to whether the environmental benefit information required by Tex. Tax Code § 11.31(c)(1) has been submitted. The applicants are exempted from submitting information regarding environmental benefit, i.e., the environmental law or rule that is being met or exceeded by the HRSG, because inclusion of HRSGs on the list represents a legislative determination that environmental benefit exists.

The Executive Director appears to contend that the Legislature's enactment of Section 11.31(m) is contrary to the Texas Constitution.[2] Neither the Executive Director nor any other entity has challenged the constitutionality of Section 11.31(m). The Executive Director's apparent attempt to override the Legislature's directive in this matter is outside the scope of his authority. As a rule, TCEQ, as an administrative agency, lacks authority to decide the constitutionality of a statute.[3] Agencies may not create for themselves any excess powers.[4] Instead, the Executive Director is bound to interpret the statute as being consistent with the Texas Constitution, and to give meaning to all of the words within the statute. Using such an approach, the appropriate interpretation is that the Legislature, through its enactment of Tex. Tax Code § 11.31(c)(1), (k), and (m), has determined that HRSGs are used to meet one or several environmental regulations, and, therefore, a HRSG applicant is not required to include that information in an application because the Texas Legislature has determined that requirement has already been met.

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[2] The Executive Director recognizes that Texas Tax Code § 11.31(k) and (m) establish an expedited review process and exempt an applicant from providing detailed information regarding the anticipated environmental benefit for property on the k-list. However, the Executive Director then eviscerates this result, stating, "Because Article VIII, Section 1-l, of the state constitution authorizes the exemption only for property used to meet or exceed an environmental rule, the Executive Director does not interpret §11.31 (m) as exempting §11.31(k)-listed property from the TCEQ's review standards set forth in 30 Tex. Admin. Code ch. 17 or mandating the issuance of a positive use determination, when the property is not used, constructed, acquired or installed to meet or exceed an environmental rule."

[3] *Edwards Aquifer Authority v. Day*, 369 S.W.3d 814, 844 (Tex. 2012).

[4] *Subaru of America, Inc. v. David McDavid Nissan, Inc.*, 84 S.W.3d 212, 220 (Tex. 2002).

Issue No. 1: BEPC's Application Cites Several Rules Met or Exceeded by Use of HRSG

Subject to, and without waiving the objection set forth in the section above, the installation and use of the HRSG and dedicated ancillary equipment allows BEPC to meet or exceed the following environmental rules or regulations:

(1) 40 C.F.R. Part 60 Subpart Da, and specifically, 40 C.F.R. § 60.44Da (Standard for Nitrogen Oxides);

(2) Clean Air Interstate Rule ("CAIR"); 30 TEX. ADMIN. CODE § 101.506;

(3) Greenhouse Gas Regulations;

(4) Best Available Control Technology ("BACT") requirements; 30 TEX. ADMIN. CODE §§ 116.10(1), 116.111(a)(2)(C), 116.160(c)(1)(A); 40 C.F.R. § 52.21(b)(12);

(5) 42 U.S.C. § 7401(c);

(6) 40 C.F.R. § 50.11 – establishing National Ambient Air Quality Standards ("NAAQS") for NO_x. HRSGs also assist in meeting NAAQS for SO_2 (40 C.F.R. § 50.17), PM_{10} (40 C.F.R. § 50.6) and CO (40 C.F.R. § 50.8).

The ED's Position is Contrary to the Plain Language of the Statute and Rule

The Executive Director has raised specific objections with respect to each of these rule citations. As an overriding objection, the Executive Director has contended that BEPC has failed to show that any of the cited rules compels an applicant to install a HRSG.[5] The applicable statute and rule address the issue differently, however. In establishing the pollution control tax abatement that is the subject of BEPC's application, the Legislature enacted Tex. Tax Code § 11.31, which states in part:

> § 11.31. POLLUTION CONTROL PROPERTY. (a) A person is entitled to an exemption from taxation of all or part of real and personal property that the person owns and that is used wholly or partly as a facility, device, or method for the control of air, water, or land pollution. ...
>
> (b) In this section, "facility, device, or method for the control of air, water, or land pollution" means land that is acquired after January 1, 1994, or any structure, building, installation, excavation, machinery, equipment, or device, and any attachment or addition to or reconstruction, replacement, or improvement of that property, that is used, constructed, acquired, or installed wholly or partly to

[5] While this contention is most specifically set forth in the NOTD's discussion of CAIR, 42 U.S.C. § 7401(c), and 40 C.F.R. §§ 50.6, 50.8, 50.11, and 50.17, since his initial rejection of BEPC's application in June 2012, the Executive Director has, in error, consistently contended that BEPC must establish that an environmental regulation mandates the installation of the HRSG.

> meet or exceed rules or regulations adopted by any environmental protection agency of the United States, this state, or a political subdivision of this state for the prevention, monitoring, control, or reduction of air, water, or land pollution.

To the extent any environmental rule must be cited in a HRSG application, the statute states that the equipment must be used, constructed, acquired, or installed wholly or partly to meet or exceed an environmental rule. It does not say that an environmental rule must mandate the use of the equipment.

Likewise, TCEQ's own rule places the emphasis on the equipment being used to meet or exceed an environmental rule, rather than on whether a law, a rule or regulation mandates the use of the equipment. The rule states, "To obtain a positive use determination, the pollution control property must be used, constructed, acquired, or installed wholly or partly to meet or exceed laws, rules, or regulations adopted by any environmental protection agency of the United States, Texas, or a political subdivision of Texas, for the prevention, monitoring, control, or reduction of air, water, or land pollution." 30 TEX. ADMIN. CODE § 17.4(a).

The Executive Director's interpretation of the statute and TCEQ's own rule is contrary to the plain language used in each. To address it formulaically or logically:

Equipment Used to Meet or Exceed Rule ≠ Rule Must Mandate Use of Equipment

Further, if it were that a rule had to mandate the use of equipment, there would be no way in which an applicant could show that its use of the equipment exceeded an environmental rule, as specifically provided for in both the statute and the rule. The Executive Director's interpretation of the statute and TCEQ's own rule makes the "exceed" portion of each meaningless and superfluous. This is contrary to the long-held and commonly understood rules of statutory and regulatory interpretation.[6]

In addition, as BEPC has stated previously, the Executive Director's position on this issue would reflect a return to the "command and control" approach to environmental regulation that Texas, and specifically, the TCEQ, has long ago rejected. For these reasons, the Executive Director's position on this issue cannot stand.

The remainder of this section addresses the specific issues raised by the Executive Director with respect to each environmental rule or requirement cited by BEPC in its application.

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[6] *See, e.g.*, *Leordeanu v. American Protection Ins. Co.*, 330 S.W. 239, 248 n. 35 (Tex. 2010) ("The Supreme Court construes statutes to give effect to every provision and ensure that no provision is rendered meaningless or superfluous."); *Columbia Med. Ctr. of Las Colinas, Inc. v. Hogue*, 271 S.W.3d 238, 256 (Tex. 2008); *City of Marshall v. City of Uncertain*, 206 S.W.3d 97, 105 (Tex. 2006).

HRSG is Used to Meet or Exceed 40 C.F.R. § 60.44Da

BEPC has included in its application a reference to 40 C.F.R. § 60.44Da, which establishes standards of performance for NO_x emissions for electric utility steam generating units for which construction commenced after September 18, 1978. BEPC asserts that the HRSG is used to meet 40 C.F.R. § 60.44Da. BEPC began construction of its electric utility steam generating unit long after September 18. 1978. As described more particularly in the Application itself, BEPC uses the HRSG to meet or exceed 40 C.F.R. § 60.44Da emissions standards primarily by reducing fossil fuel consumption and related NO_x emissions. The use of BEPC's HRSG in the combined cycle configuration described in the Application results in significantly lower NO_x emissions for the same electric power that could be generated by a simple cycle plant without pollution control equipment. The HRSG accomplishes this result by capturing/recycling and using heat generated by BEPC combustion turbines to convert water into steam to power steam (rather than natural gas) turbines which produce additional power without use of additional fossil fuel or its associated, additional NO_x emissions. Stated conversely, without its HRSG, BEPC would be unable to produce the same amount of power without producing more NO_x emissions and might well, in that instance, even exceed the environmental standards of 40 C.F.R. § 60.44Da.

The applicability of 40 C.F.R. Part 60, Subpart Da is premised on the definitions of "affected facility" and "electric utility steam generating unit". The "affected facility" to which 40 C.F.R. Part 60, Subpart Da applies is an electric utility combined cycle gas turbine other than an IGCC electric utility steam generating unit, as specified in 40 C.F.R. § 60.40Da(e)(1) through (3). 40 C.F.R. § 60.40Da(e). Note that HRSGs used with duct burners are specifically identified as "affected facilities"" for purpose of compliance with 40 C.F.R. Part 60, Subpart Da. *See* 40 C.F.R. 60.40Da(e)(1), (2). Electric utility steam generating unit" is defined as:

... any steam electric generating unit that is constructed for the purpose of supplying more than one-third of its potential electric output capacity and more than 25 MW net-electrical output to any utility power distribution system for sale.

40 C.F.R. § 60.41Da. The HRSG that is the subject of Application No. 13544 is an "affected facility" under 40 C.F.R. § 60.40Da. BEPC's citation of 40 C.F.R. § 60.44Da(a) complies with any requirement to identify an applicable EPA regulation that is met or exceeded through the use and installation of the HRSG.

Further, in the permit issued by the Executive Director to BEPC, dated October 31, 2011, for the Plant that is the subject of Application No. 13544, the Executive Director asserted that the HRSG is subject to Subpart Da. *See* Attachment B, Permit No. 25384 and PSDTX839, Special Condition 14(b). This assertion was repeated in the permit issued by the Executive Director to BEPC on February 13, 2012. See Attachment C, Permit No. 25384 and PSDTX839, Special Condition 14(b). BEPC's federal operating permit, No. O-00543, also recognizes that the HRSG is subject to Subpart Da. *See* Attachment D, Applicable Requirements Summary. The Executive

Director cannot assert that the HRSG is subject to Subpart Da for purposes of TCEQ permitting program and then deny that the HRSG is used to meet Subpart Da for purposes of the Tax Relief for Pollution Control Property Program.[7]

Even under the Executive Director's interpretation, BEPC's citation of 40 C.F.R. Part 60, Subpart Da meets the requirements necessary for BEPC to be eligible for the tax abatement. The HRSG is used to meet the requirements of 40 C.F.R. Part 60, Subpart Da. The Executive Director admits as much, when he states, "Subpart Da is a standard of performance for electric utility steam generating units, i.e., the HRSG, and provides emission limits for nitrogen oxides (NO_x), particulate matter, and sulfur dioxide (SO_2)." NOTD, p. 2. This statement establishes the clear connection between the listed equipment and the cited rule for which the Executive Director has asked. *See* NOTD, pp. 1-2.[8]

HRSG is Used to Meet the Clean Air Interstate Rule ("CAIR")

BEPC's HRSG meets or exceeds the requirements of the CAIR. CAIR was implemented by the EPA to reduce the interstate transport of pollutants, especially NO_x and sulfur dioxide. 70 Fed. Reg. 25162 (May 12, 2005). Section 101.506 of TCEQ rules implementing CAIR NO_x reductions in Texas directly relies upon increased fuel efficiency. *See* 30 TEX. ADMIN. CODE § 101.506. The increased fuel efficiency resulting from the use of a HRSG meets or exceeds Section 101.506's requirement to reduce NO_x emissions. These requirements are included as part of BEPC's federal operating permit, No. O-00543. See Attachment D, Special Terms and Conditions No. 21. Section 101.506 is applicable to BEPC, and BEPC meets this requirement through the use of the HRSG. As such, there is a clear connection between the listed equipment and the cited rule for which the Executive Director has asked, and BEPC has met this eligibility requirement for the tax abatement, to the extent it is applicable.

HRSG is Used to Exceed Greenhouse Gas Requirements

BEPC's use of the HRSG exceeds current greenhouse gas ("GHG") regulations. EPA has decided that GHGs must be regulated under the Clean Air Act and has started implementation of that regime through BACT reviews. On January 8, 2014, EPA proposed Standards of

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[7] As former Commissioner Rubenstein noted at the Commission's discussion of the pending HRSG applications, "...I don't disagree that there's great production value in having the HRSGs there. None. Nobody disputes that. But, I also don't think it's appropriate to discount the fact that that efficiency ends up in emission avoidance, and . . . we've touted the improvements in air quality that we've made because we're targeting the emissions, in large respects the increased efficiencies because of the regulations that we have also let us get there, and so we can't like it here and not like it over on this end."

[8] This conclusion is further supported by the Executive Director's prior decisions in other applications relying on 40 C.F.R. Part 60, Subpart Da. On May 1, 2008, the Executive Director issued six positive use determinations for HRSGs, each of which was premised on the HRSG's use to meet or exceed the requirements of 40 C.F.R. Part 60, Subpart Da. *See* Attachment E. In the Technical Review Document that was provided for and in support of each positive use determination, the Executive Director expressly found, among other things, that "the appropriate [supporting] rule is: 40 CFR 60.44Da."

Performance for Greenhouse Gas Emissions From New Electric Utility Generating Units. *See* 79 Fed. Reg. 1430 (Jan. 8, 2014).

Based on EPA's GHG BACT reviews to date, efficiency reflected through lower output-based emissions of GHGs is the most important factor in meeting the GHG BACT requirements.[9] In its GHG BACT Guidance Document, the EPA states, "Considering the most energy efficient technologies in the BACT analysis helps reduce the products of combustion, which includes not only GHGs but other regulated NSR pollutants (e.g. NO_x, SO_2, $PM/PM_{10}/PM_{2.5}$, CO etc.) Thus, it is also important to emphasize that energy efficiency should be considered in BACT determinations for all regulated NSR pollutants (not just GHGs)." EPA, PSD and Title V Permitting Guidance for Greenhouse Gases, at 22 (Nov. 2010).

Output-based emission reductions, such as those obtained through the use of HRSGs, have been expressly identified by the EPA as a preferred method of compliance with BACT for a wide range of pollutants. BEPC's early implementation of this pollution prevention mechanism exceed the regulatory requirements and therefore meets this eligibility requirement for the tax abatement, to the extent this eligibility requirement is applicable.

The Executive Director contends, "An applicant cannot claim eligibility for a positive use determination based on exceeding a rule that the applicant is not required to meet." NOTD, p. 2. This statement has no basis in the statute or the rule.[10] The Executive Director has provided no basis for denying a positive use determination for equipment used to obtain advanced pollution prevention gains. GHGs are subject to regulation. BEPC's early efforts to prevent the emission of such pollutants exceed these regulatory requirements. The statute and the rule in question here specifically allow for an entity to exceed regulatory requirements. The GHG regulations are an appropriate regulatory scheme on which BEPC's application can be premised. As such, BEPC has met this eligibility requirement for the tax abatement, to the extent this eligibility requirement is applicable.

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[9] EPA's recognition of the environmental benefits of combined-cycle units pre-dates its most recent consideration of the technology for purposes of reducing GHGs. In 2004, and again in 2006, EPA developed an economic impact analysis with respect to regulations it was developing under Section 111 of the Clean Air Act for new stationary combustion turbines. The proposed. and ultimately adopted, regulations were designed to reduce emissions of NO_x and sulfur dioxide generated by the combustion of fossil fuels in new combustion turbines. *See* 40 C.F.R. Part 60, Subpart KKKK; 71 Fed. Reg. 38482 (Jul. 6, 2006). In support of its rulemaking, EPA cited the environmental efficiency gains achieved from combined-cycle combustion turbines. According to EPA, the use of such a turbine system "decreases NO_x emissions by 14 percent over simple-cycle combustion turbines and 89 percent over existing ... coal electricity generation plants. In addition, CO_2 emissions will be 5 percent lower than emissions from SCCTs and 64 percent lower than existing coal plants." EPA, Economic Impact Analysis of the Stationary Combustion Turbines NSPS: Final Report, Feb. 2006, at 2-3, 2-4.

[10] The Executive Director's interpretation is set forth as a rule of general applicability. As such, to be valid, the Executive Director must go through a formal rulemaking procedure. *See El Paso Hosp. Dist. v. Texas Health and Human Services Comm'n*, 247 S.W.3d 709, 715 (Tex. 2008). Because he has not chosen to do so, any attempted application of this rule of general applicability in the absence of formal rulemaking is invalid. *Id.*

HRSG is Used to Meet BACT Requirements.

As the Executive Director is aware, BEPC's permit O-00543, does not identify particular pieces of equipment as "required Best Available Control Technology." Best Available Control Technology or BACT is defined as the reduction in total emissions that can be achieved through the use of either (i) add-on pollution control equipment; or (ii) ***production processes***, systems, methods, or work practices. 30 TEX. ADMIN. CODE § 116.10(1) (emphasis added). A HRSG serves as part of the production process and reduces the total NO_x emissions from the facility.

BACT is an issue that is addressed through a permit application (*see, e.g.*, Attachment F) and TCEQ's processing of that permit application (*see, e.g.*, Attachment G). The permit reflects the results of that analysis but does not identify specific equipment as being "required Best Available Control Technology." However, as a permit application's representations are considered conditions upon which the permit is issued,[11] and are enforceable as such, BEPC is entitled to rely on these representations for purposes of establishing that the HRSG constituted BACT for the Plant, so as to establish that the HRSG meets or exceeds the requirements of 30 Tex. Admin. Code §§ 116.111(a)(2)(C), 116.160(c)(1)(A); 40 C.F.R. § 52.21(b)(12).

HRSG is Used to Meet Federal Goals of Pollution Prevention Set Forth in 42 U.S.C. § 7401(c)

This provision of the Federal Clean Air Act establishes, as a primary goal of the Act, the encouragement and promotion of pollution prevention. As the Executive Director notes, "This does not compel an applicant to install a HRSG." 2014 NOTD, p. 2. As discussed above, that is not the statutory or regulatory requirement to establish eligibility for a positive use determination. Instead, the issue is whether the use of the HRSG helps meet or meet or exceed rules or regulations adopted by any environmental protection agency of the United States, this state, or a political subdivision of this state for, among other things, the prevention or reduction of air, water, or land pollution.

HRSGs prevent pollution. This fact has been recognized explicitly by the Legislature by its inclusion of HRSGs on the list set forth in Tex. Tax Code § 11.31(k). As such, there is a clear connection between the HRSG and the pollution prevention goal established in 42 U.S.C. § 7401(c). BEPC has met this eligibility requirement for the tax abatement, to the extent it is applicable.

HRSG is Used to Meet NAAQS Requirements

BEPC's HRSG is used to meet or exceed the National Ambient Air Quality Standards ("NAAQS") for NO_x (40 C.F.R. § 50.11), along with 30 Tex. Admin. Code §§ 101.20 and 101.21 (incorporating federal standards). The use of BEPC's HRSG also assists in meeting

[11] *See* 30 TEX. ADMIN. CODE § 116.116(a).

NAAQS for SO_2 (40 C.F.R. § 50.17), PM_{10} (40 C.F.R. § 50.6) and CO (40 C.F.R. § 50.8). As the Executive Director notes, "The NAAQS is not an emission limit for a particular facility or source of pollution ..." 2014 NOTD, p. 3. This is true, but without the use of such equipment, areas of Texas would not be able to achieve compliance with the NAAQS. It is for this reason that the EPA has adopted standards such as those set forth in 40 C.F.R. Part 60, Subpart Da, as well as CAIR. Further, it is why these requirements have been incorporated into TCEQ's rules and the permits it issues. As Commissioner Rubenstein explained, "I also don't think it's appropriate to discount the fact that that efficiency ends up in emission avoidance, and . . . we've touted the improvements in air quality that we've made because we're targeting the emissions, in large respects the increased efficiencies because of the regulations that we have also let us get there."

BEPC's HRSG is a pollution control facility, device, or method. This fact has been recognized by the Legislature. This fact has been recognized by the Commission, both formally through its Chapter 17 rulemaking, and in its discussion in the proceedings before the Commission in this matter. BEPC's HRSG is used to meet NAAQS and BEPC has met this eligibility requirement for the tax abatement, to the extent it is applicable.

Issue No. 2: The ED's Mandated Inputs are Contrary to Tex. Tax Code § 11.31(b)

The Executive Director correctly notes that BEPC submitted five approaches for calculating a partial use determination. In the 2013 NOTD, the Executive Director requested that BEPC calculate a partial use determination using specific inputs for the variables set forth in the Cost Analysis Procedure set forth in 30 Tex. Admin. Code § 17.17(b). While BEPC objected and continues to object to the mandated inputs,[12] as this action constitutes improper and illegal rulemaking, BEPC provided the requested calculation. The mandated calculation resulted in a partial use determination of -605.08%.

In addition, in an effort to reach a resolution of this matter, and without waiving its rights to pursue a partial use determination of 64.29%, BEPC proposed four other calculations for the Executive Director's consideration. Two involved approaches that did not follow the CAP formula, specifically: (i) The Executive Director's 2008 Adopted Recommendation, which proposed an across-the-board 61% positive use determination for HRSG applicants; and (ii) a five-step Avoided NO_x Emissions calculation that would result in a 39.7% positive use determination. BEPC reiterates its suggestion that the Executive Director consider these approaches as a means of reaching a more reasoned calculation of a positive use determination given the flaws in the CAP formula that have been demonstrated by BEPC and the other HRSG applicants.

[12] *See, e.g.*, Attachment J of BEPC's Response to the Executive Director's Notice of Technical Deficiency, dated June 24, 2013.

The final two (2) calculations utilized the CAP formula with inputs for the variables which were consistent with the CAP formula, but which differed from the inputs mandated by the Executive Director. In the first, BEPC proposed utilizing the cost of piping as the input for the Cost of Capital Old variable. Using this approach, the application of the CAP formula results in a positive use determination of 63.76%.

BEPC proposed the piping as "comparable equipment" that could be used to calculate the Capital Cost Old ("CCO") in the CAP formula. As stated in BEPC's previous submission in this matter, without the HRSG, exhaust gases would be conveyed via piping from the combustion chamber to a control device or stack. No additional power would be generated, and no pollution control would be achieved. With the use of the HRSG, both objectives are realized.

In the 2014 NOTD, the Executive Director asserts that allowing the CCO to be the value of the piping "would lead to a determination that a piece of production equipment, the HRSG, was installed for the single purpose of preventing pollution rather than for the purpose of producing steam for sale or use in producing electricity." With this statement and the further assertion that, instead, a boiler is the appropriate equipment for the CCO calculation, the Executive Director errs in three ways.

First, the HRSG is not solely production equipment. As the Executive Director well knows and as the Legislature has expressly recognized, the HRSG serves two functions: (i) it allows BEPC to reuse heat to generate steam and thereby generate more electricity; and (ii) by doing so, it reduces the amount of energy needed to generate the increased amount of electricity and, as a result, prevents pollution that would occur in the absence of the HRSG. The Legislature has recognized that the HRSG is pollution control property. The Executive Director and the Commission, through rulemaking, have also recognized this fact.

Second, BEPC has never contended that the HRSG was installed solely for the purpose of pollution control. The process in which BEPC and the Executive Director are currently engaged is to determine the allocation of the HRSG's two functions, i.e., what percentage is attributable to production and what percentage is attributable to pollution control. A resulting consequence is that the two percentages must add up to 100%. As noted herein, and in BEPC's previous submissions, the Executive Director's use and interpretation of the CAP formula does not meet this test.

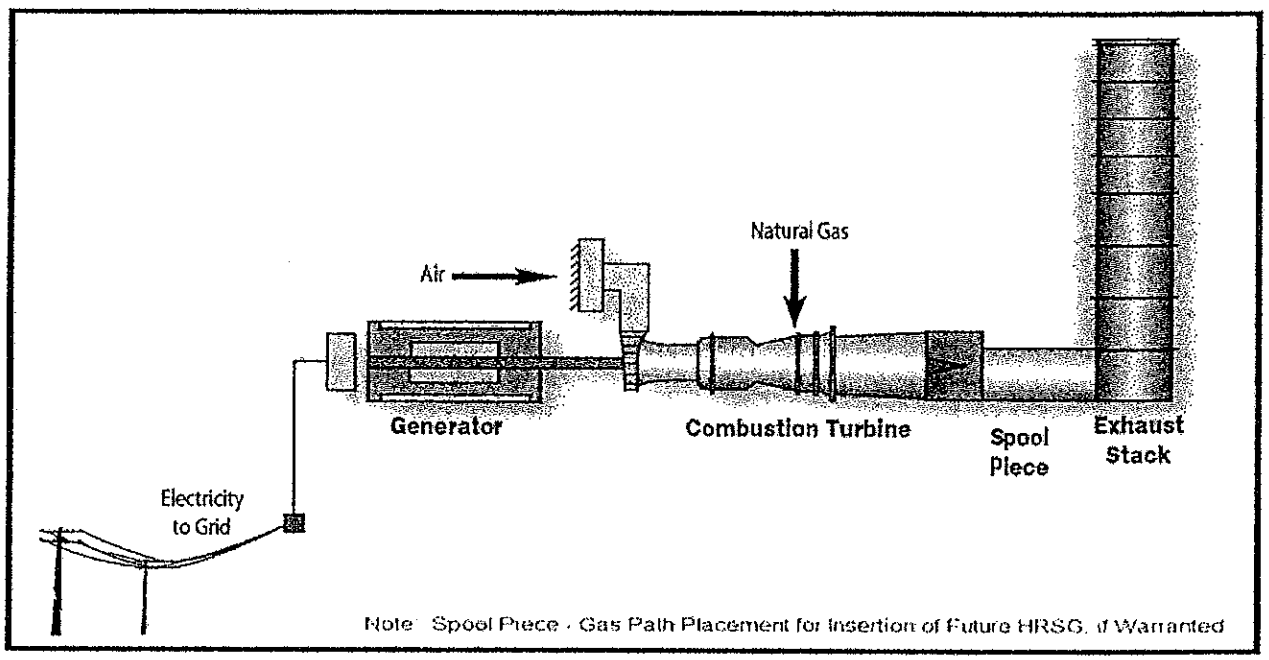
Third, by fiat, the Executive Director has determined that a boiler sized to create the same amount of steam as the HRSG is *the*, i.e., the one and only, appropriate comparable equipment that may be used in a CAP calculation for a HRSG. The Executive Director has exceeded his authority by mandating one and only one approach to this variable, and further, in that regard, mandating the consideration of quite possibly the most expensive equipment possible. "Comparable equipment" is not a defined term in 30 Tex. Admin. Code ch. 17. "Comparable" is defined in normal usage as similar, or capable of comparison. Synonyms include "analogous,"

"corresponding," "matching," and "resembling." BEPC asserts that replacement boilers do not match or resemble a HRSG, and therefore the Executive Director's mandate is improper.

Further, even if replacement boilers were analogous to a HRSG, it cannot be argued that replacement boilers are the only comparable equipment. If a CCO must be used, BEPC asserts that an appropriate comparable equipment is a pipe that would vent heat in the absence of a HRSG.

In BEPC's final proposed calculation, BEPC proposed using zero as the CCO and NPVMP variables. Using these inputs for the designated variables, BEPC's HRSG would be entitled to a 100% positive use determination. As set forth above, BEPC asserts that replacement boilers do not match or resemble a HRSG, and therefore the Executive Director's mandate is improper. Indeed, an application of TCEQ's hierarchical definition of "Capital Cost Old," found in 30 Tex. Admin. Code § 17.17(c)(1), note 3, will conclude that no CCO should be used in the CAP calculation for a HRSG.

The mandate of "comparable equipment" that is, in fact, not comparable as hypothetical "replaced" equipment is inappropriate and constitutes improper and illegal rulemaking. On the basis of this objection, BEPC respectfully requests that the Executive Director determine that there be no CCO for CAP calculations related to the HRSG or, in the alternative, that the hypothetical "replaced" equipment be considered to be the piping reflected as "Spool Piece" in the diagram set forth below.



BEPC reasserts the use determination approaches provided in its response to the 2013 NOTD. These approaches all provide a basis for determining the allocation of the HRSG's two functions and result in positive use determinations that are consistent with the Legislature's determination that HRSGs are pollution control property. BEPC urges the Executive Director to reconsider his position and work with the HRSG applicants to resolve the pending applications through the use of one of the approaches that BEPC has proposed.

In his 2014 NOTD, the Executive Director has asked for a listing of the equipment designated as dedicated ancillary equipment, including a statement as to whether the listing includes the steam turbine and associated water systems. In addition, the Executive Director has required that BEPC remove from the calculation of Production Costs any costs related to operating the gas turbine, the water systems, or the steam turbine. The Executive Director acknowledged that his initial refusal to include costs related to the operation of the duct burners, including fuel costs, was in error, and he requested that these costs be included in the calculation of Production Costs.

BEPC has attached the equipment list, which shows that the steam turbine, cooling tower and various water systems, among other items, are not included as part of the cost of the HRSG that is being claimed by BEPC in the pending application. *See* Attachment H. In compliance with the Executive Director's directive, the calculation set forth below is based on the Executive Director's limited definition of HRSG equipment that is eligible for a positive use determination.[13]

The Executive Director, through the processing of this application, has also narrowed the scope of the CAP's Production Cost variable by asserting that the cost attributed to the

[13] While the Executive Director contends that equipment such as the feedwater systems, boiler systems, chemical injection, cooling air systems, nitrogen systems, and condensate systems are all production equipment for which a positive use determination is not available, BEPC disagrees and reserves the right to seek a positive use determination for this equipment, under a separate application. These systems are essential to the operation of the HRSG. Without these pieces of equipment, the HRSG will not function and neither the production nor the pollution prevention benefits will be achieved. The HRSG must include all ancillary equipment and production costs required for the equipment to operate. The HRSG itself does not function without the heat generated from fuel burned by a combustion turbine ("CT"), nor will it function without water to make steam. In order for water to be introduced to the HRSG, the following equipment must be present: the feed water system, cooling air systems, condensate systems, and chemical injection systems. The production costs essential for HRSG to operate, and produce the required megawatts ("MW") demanded by the grid, must include CT fuel consumption, duct burner fuel consumption, and Steam Turbine production costs. In order for the HRSG to produce the MW required to supply the grid with the load required by ERCOT while limiting the total emissions produced, as required by applicable environmental regulations, a HRSG must function as designed. This design includes the feed water system, cooling air systems, condensate systems, and chemical injection systems. The allocation of the production and pollution control functions of the equipment serves to appropriately identify the proportion of the equipment costs for which a tax abatement may be obtained. BEPC reserves the right to seek a positive use determination for this equipment, under a separate application.

production of electricity, which the Executive Director has designated as the marketable product, must exclude costs relating to operating the gas turbine or the steam turbine including fuel costs.

Without the operation of these units, and their associated expenses (including fuel costs), no electricity would be generated from any steam produced via the HRSG, and therefore no marketable product would be generated. The Executive Director cannot have it both ways. If electricity is the marketable product, the HRSG Applicants must be allowed to take into account the costs (and the equipment) associated with generating that marketable product as part of its NPVMP calculation. TCEQ's rules mandate it.

The exclusion of fuel costs from Production Cost is particularly problematic and inappropriate. "Production Cost" expressly includes the cost of "raw materials." *See* 30 TEX. ADMIN. CODE § 17.17(c)(2). In this context, fuel is the raw material for the production of the steam and its costs are an element of Production Cost, by definition. Additional costs that are included in Production Cost include storage, transportation, and personnel costs. *See id.* The interpretation of the elements to be included in, and excluded from, the calculation of NPVMP is inaccurate and constitutes improper and illegal rulemaking.

Without waiving its objections to the Executive Director's directives included in the NOTD, as set forth above, and in prior proceedings and filings in this matter, BEPC has prepared a revised calculation in conformance with these directives. This calculation is prepared for purposes of responding to the 2014 NOTD lest the Executive Director find that BEPC has failed to submit a complete application and therefore determine that its application is void. BEPC expressly reserves its right to contest the Executive Director's directives. Using the Executive Director's mandated approach, the use determination calculation is -82.55%. *See* Attachment I.

As can be seen, it is BEPC's conclusion that the calculation, using the specific inputs mandated by the Executive Director, will in each and every case result in a negative use determination, based on a CAP calculation that will be highly negative. Such a result is no more appropriate than a situation in which a calculation consistently results in a use determination of greater than 100%. This result is contrary to the Legislature's enactment of Tex. Tax Code § 11.31(b). HRSGs have been statutorily designated as pollution control equipment. As such, some portion of the value of that equipment must be attributed to pollution control, and provided a tax exemption. A result of zero, less than zero, or far less than zero is not valid, any more than a result of greater than 100% would be valid. The purpose of the calculation is to determine what percentage of the equipment's value is attributable to production and what percentage is attributable to pollution control. The percentages must add up to 100%. Because the formula is capable of generating a naught or a negative number, it is inconsistent with state law, and invalid as a matter of law. Given this outcome, the Executive Director must revisit the mandated inputs and develop an approach that is consistent with the Legislature mandate that HRSGs constitute pollution control equipment.

Subject to its objections stated above, BEPC appreciates the opportunity to provide the enclosed additional information for the Executive Director consideration. BEPC understands that TCEQ will be receiving additional information from the other HRSG Applicants as well that might be utilized to resolve the pending HRSG applications. BEPC is willing and available to meet with the Executive Director and his staff to attempt to resolve these pending applications in an equitable manner. Please contact me if you have any questions or require any additional explanation or information in support of BEPC Application No. 13544.

Sincerely,

Paul C. Sarahan

PS/cb
Attachments

ATTACHMENT A

Bryan W. Shaw, Ph.D., P.E., *Chairman*
Toby Baker, *Commissioner*
Zak Covar, *Commissioner*
Richard A. Hyde, P.E., *Executive Director*

Rec'd 2-6-14

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

February 3, 2014

Mr. Jim Harris
Agent
H & H Associates
406 FM 3016
Grapeland, Texas 75844

Re: Notice of Technical Deficiency
Brazos Electric Power Cooperative, Inc.
Johnson County Generation Facility
Cleburne (Johnson County)
Regulated Entity Number: RN100221985
Customer Reference Number: CN600128821
Application Number: 13544

Dear Mr. Harris:

This letter responds to Brazos Electric Power Cooperative, Inc.'s Application for Use Determination, received April 27, 2009 pursuant to the Texas Commission on Environmental Quality's (TCEQ) Tax Relief for Pollution Control Property Program for the Johnson County Generation Facility.

The TCEQ has conducted further technical review and determined that additional information required by Title 30 Texas Administrative Code (TAC) §17.10 is warranted for application #13544.

The Executive Director interprets Texas Tax Code (TTC) §§11.31(k) and (m) as establishing an expedited review process and exempting an applicant from providing detailed information regarding the anticipated environmental benefit for property on the k-list. Because Article VIII, Section 1-l, of the state constitution authorizes the exemption only for property used to meet or exceed an environmental rule, the Executive Director does not interpret TTC §11.31 subsection (m) as exempting §11.31(k)-listed property from the TCEQ's review standards at Title 30 Texas Administrative Code (TAC) Chapter 17 or mandating the issuance of a positive use determination, when the property is not used, constructed, acquired, or installed to meet or exceed an environmental rule.

Please revise your application to include the following information.

Issue 1 – Review of Environmental Rule Citations

In review of the facility's air permits and associated filings, the following comments on rule citations are in part based on representations made in the permit documents. It does not appear that sufficient information has been provided to establish a clear connection

between the listed equipment and the cited rules. For each cited rule, please provide an explanation of how the equipment is used to meet a requirement in the rule.

New Source Performance Standard (NSPS) Subpart Da is a standard of performance for electric utility steam generating units, i.e., the HRSG, and provides emission limits for nitrogen oxides (NOx), particulate matter, and sulfur dioxide. Given that Da only applies to the HRSG itself, it does not appear that use of the HRSG is required to meet Da or that it helps the facility meet the emission limit for the HRSG itself. The absence of a HRSG (that is subject to regulation under Da) would not affect emission limitations of other sources at the plant, e.g., the gas turbine (regulated under GG). Please explain in detail how a HRSG is used to meet the requirements of Da.

Regarding the Clean Air Interstate Rule (CAIR), CAIR is a cap and trade program that allocates allowances to all electric generating units. Please explain how a Heat Recovery Steam Generator (HRSG) is required to meet a CAIR requirement.

Title 40 CFR §52.21(b)(49)(v) states, "Beginning July 1, 2011, in addition to the provisions in paragraph (b)(49)(iv) of this section, the pollutant greenhouse gases (GHGs) shall also be subject to regulation (a) at a new stationary source that will emit or have the potential to emit 100,000 tpy carbon dioxide equivalent (CO_2e); or (b) At an existing stationary source that emits or has the potential to emit 100,000 tpy CO_2e, when such stationary source undertakes a physical change or change in the method of operation that will result in an emissions increase of 75,000 tpy CO_2e or more." The Johnson County Generation Facility was authorized by construction air permit 25384 which was issued December 6, 1994. The air permit general conditions required that construction be started no more than 18 months after permit issuance. Therefore, criterion (a) above does not apply. There is no documentation that the site has undergone a modification which would trigger criterion (b) above. Similarly, the application has not demonstrated that the site has gone through a major modification which would trigger a control technology review as described in 40 CFR §52.21(j). An applicant cannot claim eligibility for a positive use determination based on exceeding a rule that the applicant is not required to meet.

Best Available Control Technology (BACT) analysis is completed in conjunction with construction and amendment air permit applications. Documentation pertaining to air permit 25384 has been reviewed. We found no representations of HRSGs providing pollution control. Agency approved BACT for control of nitrogen oxides (NO_x) was selective catalytic reduction (SCR).

Attachment B to your June 24, 2013 response includes, "However, as a permit application's representations are considered conditions upon which the permit is issued, and are enforceable as such, BEPC is entitled to rely on these representations for purposes of establishing that the HRSG constitutes BACT for the Plant. . ." It is correct that permit application representations are considered conditions upon which issuance of the permit is predicated. However, air permit applications contain many representations and not all such representations are related to BACT.

42 U.S.C. §7401(c) states, "A primary goal of this chapter is to encourage or otherwise promote reasonable Federal, State, and local governmental actions, consistent with the provisions of this chapter, for pollution prevention." This does not compel an applicant to install a HRSG.

30 TAC §§117.450, 117.454, 117.456 and 117.9030 apply to major sources within the Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area. More appropriate citations would pertain to Utility Electric Generation Sources within the Dallas-Fort Worth Eight-Hour

Ozone Nonattainment Area. If you contend that there is an appropriate citation in Chapter 117 that would support use determination application 13544, please provide the specific citation and explain how the application equipment enables the applicant to meet or exceed that rule.

The application cites 40 CFR §§50.11, 50.15, 50.17, 50.6, and 50.8 which are the National Ambient Air Quality Standard (NAAQS) for NO2, O3, SO2, PM10, and CO respectively. States employ state implementation plans and incorporated air permitting programs to ensure continued compliance with the NAAQS in attainment areas and reasonable progress toward attainment in non-attainment areas. NAAQS are ambient air concentrations promulgated by the EPA to protect public health and welfare. The NAAQS is not an emission limit for a particular facility or source of pollution and does not require specific facilities to use any particular pollution controls.

Issue 2 – Calculation of an Appropriate Partial Positive Use Determination

Your response to the February 21, 2013 request for additional information requests a partial positive use determination based on the Cost Analysis Procedure (CAP) located in 30 TAC §17.17. In addition the response provides alternative methodologies for calculating a partial positive use determination. One method proposes using the calculation included in the executive director's December 3, 2008 HRSG appeal brief, another method is based on an Avoided Emissions approach, and a third method is based on using the CAP with various modifications to equation variables.

First we will evaluate the alternative methods. The first proposed methodology is based on a calculation included in the brief filed on December 3, 2008, by the executive director in response to the HRSG appeals. The brief included a proposed partial use determination calculation that was based on increased efficiency. Between the filing of the brief and the February 2009 agenda date the calculation was re-evaluated and determined to not be appropriate since the percentage yielded on a positive use determination increases as the efficiency of the equipment decreases. The executive director does not support the use of this calculation.

The second proposed methodology proposes an Avoided Emissions approach that compares the thermal output of a combined cycle facility and a simple cycle facility. Please correct Step 5 of the calculation. The percentage NOx emissions reduction attributable to the HRSG is more accurately calculated as (Output Baseline – Output Subject)/Output Baseline.

The other methods use the CAP to calculate a proposed use determination percentage. Capital Cost New is defined as the HRSG and dedicated ancillary equipment. Capital Cost Old is defined as the value of "piping necessary to gap created by the absence of the HRSG" and $0. Net Present Value of Marketable Product is defined as either $0 or is calculated using fuel costs as part of Production Costs.

Please provide a listing of the equipment listed as dedicated ancillary equipment. Does this included the steam turbine and associated water systems? If so please remove them from the application. During the 2008 technical review the executive director evaluated steam turbines and determined that they are installed for the sole purpose of producing electricity and not as pollution control equipment. As such, steam turbines are not eligible for a positive use determination. The water systems are considered to be production equipment and the TCEQ has consistently issued negative determinations for this type of equipment.

Piping is used to convey exhaust gases from the combustion chamber to a control device or stack. HRSG's are used to convert energy contained in waste heat into steam. The appropriate comparable equipment for Capital Cost Old (CCO) is a boiler sized to create the same amount of steam as the HRSG. Allowing CCO to be $0 or the value of a piece of pipe would lead to a determination that a piece of production equipment, the HRSG, was installed for the single purpose of preventing pollution rather than for the purpose of producing electricity.

Production Costs are the costs related to operating the equipment for which the positive use determination is being requested. In the request for additional information we stated that Production Costs were to exclude "costs related to operating the gas turbine, associated duct burners, or the steam turbine including fuel costs." The appropriate costs to be included in Production Costs are those costs related to operating the HRSG. We agree that this includes the costs related to the operation of the duct burners including fuel costs. We do not agree that production costs include costs related to operating the gas turbine, the water systems, or the steam turbine.

Please resubmit your application using the CAP with the variables calculated as explained in the February 21, 2013, letter with the exception of additional production costs as explained in the preceding paragraph.

The TCEQ appreciates your response in this matter. The revised application must be submitted by March 21, 2014 to the TCEQ Tax Relief for Pollution Control Property Program, MC-110, P.O. Box 13087, Austin, Texas 78711-3087. Failure to submit a complete application, including the requested information, may result in your application being voided and the associated application fee being forfeited in accordance with 30 TAC §17.20(b).

If you have questions regarding this letter or need further assistance, please contact Ronald Hatlett of the Tax Relief for Pollution Control Property Program by telephone at (512) 239-6348, by e-mail at ronald.hatlett@tceq.texas.gov, or write to the Texas Commission on Environmental Quality, Tax Relief for Pollution Control Property Program, MC-110, P.O. Box 13087, Austin, Texas 78711-3087.

Sincerely,

Chance Goodin, Team Leader
Stationary Source Programs
Air Quality Division

CG/RH

ATTACHMENT B

1. Top of document
2. Emission Sources - Maximum Allowable Emission Rates
3. Air Contaminants Data

Section 1 - Document

Emission Sources - Maximum Allowable Emission Rates

Permit Number 25384 and PSDTX839

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)
E-CT/HRSG	Turbine and 375 MMBtu/hr Heat Recovery Steam Generator (5)	NO_x	115.7	272.8
		NO_x (MSS)(7)	330.0	-
		CO	348.5	462.6
		CO (MSS)(7)	879.0	-
		VOC	30.0	42.3
		SO_2	87.22	72.5
		PM	57.8	65.2
		PM_{10}	57	61.9
		NH_3	32.5	130.5
		Pb	0.1	<0.1
FP-1	Fire Pump (6) 182 Hp	NO_x	1.87	0.02
		CO	0.41	<0.01
		VOC	0.15	<0.01
		SO_2	0.12	<0.01
		PM	0.13	<0.01
SO_4-TK	Sulfuric Acid Tank	VOC	<0.1	<0.1
OIL-TK1	Fuel Oil Tank	VOC	0.6	0.3
OIL-TK2	Fuel Oil Tank	VOC	0.6	0.3
MSSFUG	MSSFUG	VOC	0.26	0.05
		$PM/PM_{10}/PM_{2.5}$	0.05	<0.01

		NO_x	<0.01	<0.01
		NH_3	0.16	<0.01

(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) VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1

NO_x - total oxides of nitrogen

SO_2 - sulfur dioxide

PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$, as represented

PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$, as represented

$PM_{2.5}$ - total particulate matter equal to or less than 2.5 microns in diameter, as represented

CO - carbon monoxide

Pb - lead

NH_3 - Ammonia

(4) Compliance with annual emission limits (tons per year) is based on a 12 month rolling period.

(5) The allowable emissions shown represent worse-case emissions for 8,040 hours and 720 hours of natural gas and fuel oil firing, respectively, in the CT. The HRSG fires natural gas only and supplies steam to a 104 MW steam turbine.

(6) Source qualifies for Permit by Rule 30 TAC ' 106.511.

(7) For each pollutant whose emissions during planned MSS activities are measured using a CEMS, the MSS lb/hr limits apply only during each clock hour that includes one or more minutes of MSS activities. During all other clock hours, the normal lb/hr limits apply.

Date: October 31, 2011

Headers

Permit Number 25384 and PSDTX839

Page

Emission Sources - Maximum Allowable Emission Rates

Footers

Project Number: 162448

Project Number: 162448

Published by GroupWise

1. Top of document
    1. For each pollutant emitted during ILE planned maintenance activities, the permit holder shall annually confirm the continued validity of the estimated potential to emit represented in the permit application for all ILE planned maintenance activities. The total emissions from all ILE planned maintenance activities (See Attachment A) shall be considered to be no more than the estimated potential to emit for those activities that are represented in the permit application.
    2. All other maintenance activities may be authorized by 30 TAC § 106.263.

Section 1 - Document

Special Conditions

Permit Numbers 25384 and PSDTX839

Emission Limitations and Operating Specifications

1. This permit covers only those sources of emissions listed in the attached table entitled AEmission Sources - Maximum Allowable Emission Rates,@ and those sources are limited to the emission limits and other conditions specified in the attached table. The annual rates are based on a rolling 12-month period.

2. A copy of this permit, the June 1994 permit application, and any subsequent permit-related correspondence shall be kept at the plant site and made available at the request of personnel from the Texas Commission on Environmental Quality (TCEQ) or the local air pollution control agency. In addition, the holder of this permit shall maintain an updated site arrangement of the facility showing the location and emission point numbers (EPNs) for all sources listed on the maximum allowable emission rates table (MAERT).

3. Fuel fired in the Westinghouse Model W501F Gas Combustion Turbine (CT) and the duct burner of the heat recovery steam generator (HRSG) are limited as follows:

    A. Fuels fired in the CT:

        1. Primary fuel - pipeline-quality, sweet natural gas containing no more than 5.0 grains total sulfur and 0.25 grain of hydrogen sulfide (H_2S) per 100 dry standard cubic feet (dscf).

        2. Backup fuel - refinery-grade, first-run distillate fuel oil containing no more than 0.05 percent

sulfur by weight. Fuel oil may be fired as a backup fuel for a maximum of 720 hours per year. The permit holder must show compliance with the 720 hour limit on a rolling 12-month average.

B. Fuel fired in the HRSG duct burner is limited to pipeline-quality, sweet natural gas containing no more than 5.0 grains total sulfur and 0.25 grain of H_2S per 100 dscf.

4. The permit holder shall use steam injection to control the emissions contribution of nitrogen oxides (NO_x) from the CT prior to entering the HRSG and selective catalytic reduction (SCR) units.

5. The stack gases of the CT/HRSG Unit (EPN E-CT/HRSG) shall not exceed the emission concentrations stated below.

A. While the CT/HRSG unit is firing natural gas at base load, the concentration of NO_x and carbon monoxide (CO) in the stack gases of EPN E-CT/HRSG shall not exceed 9 parts per million by volume on a dry basis (ppmvd) and 25 ppmvd, respectively, when corrected to 15 percent oxygen (O_2). Base load is defined as operation equal to or greater than 120 MW. **(10/11)**

B. While the CT is firing fuel oil and the HRSG is firing natural gas, each at base load, the concentration of NO_x and CO in the stack gases of EPN E-CT/HRSG shall not exceed 15.5 ppmvd and 25 ppmvd, respectively, when corrected to 15 percent O_2.

6. The HRSG duct burner is limited to a maximum heat input capacity of 375 MMBtu/hr. The heat input shall be calculated on the higher heating value (HHV) of the fuel.

7. Upon request by the Director of the TCEQ Dallas/Fort Worth (DFW) Regional Office or the Executive Director of the TCEQ or any local air pollution control program having jurisdiction, the holder of this permit shall provide a sample and/or an analysis of the fuel fired in this facility or shall allow air pollution control agency representatives to obtain a sample for analysis.

8. Except during MSS activities, the opacity shall not exceed five percent averaged over a six-minute period from each stack or vent. During periods when the CT is firing fuel oil, the opacity limitation shall be 10 percent. During MSS activities, the opacity shall not exceed 15 percent (or other applicable opacity limit specified in Title 30 Texas Administrative Code (TAC) § 111.111(a)(1)(c)). Each determination shall be made by first observing for visible emissions while each facility is in operation. Observations shall be made at least 15 feet and no more than 0.25 miles from the emission point. If

visible emissions are observed from an emission point, then the opacity shall be determined and documented within 24 hours for that emission point using Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60), Appendix A, Test Method 9. Contributions from uncombined water shall not be included in determining compliance with this condition. Observations shall be performed and recorded quarterly. If the opacity exceeds five percent during normal operations, 10 percent when firing fuel oil, or 15 percent during MSS activities, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one week of first observation. **(10/11)**

Anhydrous Ammonia (NH_3)

9. The concentration of NH_3 in the exhaust gases of the EPN E-CT/HRSG shall not exceed 10 parts per million by volume (ppmv) when corrected to 15 percent O_2.

10. The permit holder shall maintain a quantity of no more than 12,000 gallons of NH_3 on-site at any time. Additionally, the permit holder shall maintain prevention and protection measures for the NH_3 storage system as represented in Table 4-1 of the supplemental letter dated August 22, 1994, submitted during the review of the June 1994 application for this permit. The letter includes the following:

    A. Relief valves shall be discharged to the HRSG Stack (EPN E-CT/HRSG) rather than releasing directly to the atmosphere at ground level.

    B. The tank area will be diked so as to contain at least the volume of the pressure vessel.

    C. A water deluge system shall be installed to cover the tank and diked area to mitigate any airborne releases of NH_3. The water deluge system must activate when a level of 200 ppmv of NH_3 is detected.

    D. Any NH_3 solution contained by the dike area shall be immediately transported to a safe disposal area.

11. In the event of a release of the NH_3 from the liquid fill line, pressure vessel due to overpressurization, process line to the SCR system, or the vapor return lines from the vaporizer or any other accidental release of NH_3, the permit holder shall follow the contingency plan and mitigation procedures set out in Sections 5.0 and 6.0 of the August 22, 1994 letter regarding the use of NH_3.

12. In addition to the requirements of Special Condition Nos. 10 and 11, the permit holder shall maintain the piping and valves in NH_3 service as follows:

    A. All operating practices and procedures relating to the handling and storage of NH_3 shall conform to the safety recommendations specified for that compound by guidelines of the American National Standards Institute and the Compressed Gas Association.

    B. Audio, olfactory, and visual checks for NH_3 leaks within the operating area shall be made every four hours.

    C. Immediately, but no later than one hour upon the detection of a leak, plant personnel shall take the following actions:

        1. Locate and isolate the leak, if necessary.

        2. Commence repair or replacement of the leaking component.

        3. Use a leak collection/containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

13. All necessary plant employees shall undergo proper training in the maintenance, mitigation, and contingency procedures necessary to prevent, control, or handle accidental releases of NH_3.

Federal Applicability

14. These facilities shall comply with applicable requirements of the EPA regulations on Standards of Performance for New Stationary Sources, Title 40 Code of Federal Regulations (40 CFR) Part 60, promulgated for:

    A. General Conditions, Subpart A.

B. The heat recovery steam generators are subject to the requirements of Subpart Da, Standards of Performance for Electric Utility Steam Generating Units.

C. The Westinghouse Model W501F Gas Turbine is subject to the requirements of Subpart GG, Standards of Performance for Stationary Gas Turbines.

If any condition of this permit is more stringent than the regulations so incorporated, then for the purposes of complying with this permit, the permit shall govern and be the standard by which compliance shall be demonstrated.

Initial Determination of Compliance

15. Sampling ports and platforms shall be incorporated into the design of the HRSG exhaust stacks according to the specifications set forth in the attachment entitled AChapter 2, Stack Sampling Facilities.@ Alternate sampling facility designs may be submitted for approval by the TCEQ DFW Regional Director or the TCEQ Air Permits Division.

16. The holder of this permit shall perform stack sampling and other testing as required to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from EPN E-CT/HRSG. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and in accordance with the appropriate EPA Reference Methods for NO_x, CO, volatile organic compounds (VOC), sulfur dioxide (SO_2), NH_3, particulate matter less than 10 microns in diameter (PM_{10}), and opacity.

Fuel sampling using the methods and procedures of 40 CFR ' 60.335(d) may be conducted in lieu of stack sampling for SO_2. If fuel sampling is used, compliance with New Source Performance Standards (NSPS) Subpart GG, SO_2 limits shall be based on 100 percent conversion of the sulfur in the fuel to SO_2. Any deviations from those procedures must be approved by the TCEQ Air Permits Division or the TCEQ DFW Regional Director prior to sampling. The TCEQ Executive Director or his designated representative shall be afforded the opportunity to observe all such sampling.

The holder of this permit is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense.

A. The TCEQ DFW Regional Office shall be contacted as soon as testing is scheduled but not less than 45 days prior to sampling to schedule a pretest meeting.

The notice shall include:

1. Date for pretest meeting.

2. Date sampling will occur.

3. Name of firm conducting sampling.

4. Type of sampling equipment to be used.

5. Method or procedure to be used in sampling.

6. Procedure used to determine turbine loads during and after the sampling period.

7. A plan to develop computer-generated calculations of NO_x and CO emissions in pounds per hour and tons per rolling 12-month period. The plan shall include the equations used to convert the monitored concentrations to mass emission rates. The computer calculated hourly values are to be generated and compared to the initial stack sampling results to demonstrate the relative accuracy of the computer-generated output.

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. A written proposed description of any deviation from sampling procedures specified in permit conditions, TCEQ, or EPA sampling procedures shall be made available to the TCEQ prior to the pretest meeting. The TCEQ DFW Regional Director or the TCEQ Air Permits Division shall approve or disapprove of any deviation from specified sampling procedures. Requests to waive testing for any pollutant specified in this condition shall be submitted to the TCEQ Office Air, Air Permits Division. Test waivers and alternate/equivalent procedure proposals for NSPS testing which must have EPA approval shall be submitted to the TCEQ Air Permits Division in Austin.

B. Air contaminants emitted from the CT/HRSG unit to be tested for include (but are not limited to) NO_x, CO, SO_2, VOC, PM_{10}, NH_3, O_2, and opacity. The CT shall be tested at a minimum of four points in the normal operating range including full load for the atmospheric conditions which exist during testing while firing natural gas and fuel oil. The HRSG duct burners shall be tested at the maximum firing rate of 450 MMBtu/hr (HHV) while firing natural gas.

C. Sampling shall occur within 60 days after achieving the maximum production rate at which the facility will be operated but no later than 180 days after initial start-up. The TCEQ and EPA may require additional sampling at other times as they deem appropriate.

D. Within 60 days after the completion of the testing and sampling required herein, copies of the sampling report shall be distributed as follows.

One copy to the TCEQ DFW Regional Office.

One copy to the TCEQ Office of Air.

One copy to the EPA Region 6 in Dallas.

Continuous Determination of Compliance

17. The holder of this permit shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) to:

A. Measure and record the concentrations of NO_x, CO, NH_3, and O_2 at the CT/HRSG exhaust stack. The NO_x and CO concentrations shall be corrected and reported in accordance with Special Condition No. 5. The NH_3 concentrations shall be corrected and reported in accordance with Special Condition No. 9.

B. The CEMS required in Special Condition No. 17A shall comply with the following requirements:

1. The CEMS shall 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 60, Appendix B. The Performance Specification tests shall be conducted during the sampling required by Special Condition No. 16, and written copies of the results shall be submitted within 60 days of completion of the tests to the TCEQ DFW Regional Office and the Air Enforcement Branch of EPA in Dallas.

2. The system shall be zeroed and spanned daily and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in 40 CFR Part 60, Appendix B. Each gaseous monitor shall be quality-assured at least quarterly using cylinder gas audits (CGA). The CGA method to be used is contained in 40 CFR Part 60, Appendix F, Procedure 1, ' 5.1.2. An equivalent method approved by the EPA and TCEQ may be used.

3. The gaseous monitoring data shall be reduced to hourly average concentrations at least once everyday, using a minimum of four equally-spaced data points from each one-hour period.

Two valid data points shall be generated during the hourly period in which zero and span is performed.

4. The CEMS shall demonstrate 90 percent monitor data availability on a monthly basis. The percent monitor data availability shall be calculated as the total unit operating hours for which quality-assured data was recorded divided by the total unit operating hours.

5. All CGA exceedances greater than "15 percent accuracy and any unscheduled CEMS downtime shall be reported to the TCEQ Fort Worth Regional Office and the Air Enforcement Branch of EPA in Dallas, and necessary corrective action shall be taken. Unscheduled CEMS downtime is any CEMS downtime not required for daily zero and span checks, quarterly CGAs, and annual relative accuracy test audits. Supplemental stack concentration measurements may be required at the discretion of the TCEQ DFW Regional Director or the EPA.

6. The CEMS shall demonstrate an annual system reliability of at least 90 percent (downtime does not include daily zero and span measurement time or cogeneration unit downtime) or options to increase system reliability to an acceptable value, including a redundant CEMS, may be required by the TCEQ DFW Regional Director.

7. For NSPS sources subject to Appendix F, the TCEQ DFW Regional Office and EPA NSRS in Dallas shall be notified at least 30 days prior to each annual relative accuracy testing audit in order to provide them the opportunity to observe the testing.

18. The holder of this permit shall additionally install, calibrate, maintain, and operate continuous monitoring systems to monitor and record the average hourly fuel and water consumption in the gas turbines. The systems shall be accurate to "5.0 percent, and the system shall be approved by the Air Permits Division of the TCEQ prior to conducting the initial compliance demonstration required by Special Condition No. 16.

19. If the NH_3 CEMS is not able to show continuous demonstration of compliance, then the facility shall implement wet chemical sampling or an alternative TCEQ-approved method of estimating NH_3 emissions. The holder of this permit shall monitor NH_3 concentration (ppmv) and stack gas flow rate in standard cubic feet per minute in the SCR unit exhaust stack. The measured NH_3 concentration and flow rate shall be used to calculate the NH_3 emission rate in pounds per hour and cumulative tons per year to determine compliance with Special Condition Nos. 1 and 9.

20. The holder of this permit shall develop a program to calculate the total mass flow rate through each

cogeneration train by using a mass balance of fuel, steam, and ammonia into the CT/HRSG unit and exhaust flow out of the HRSG stack to ensure continuous compliance with Special Condition No. 5.

A. Using the calculated flow rate and the concentrations of NO_x, NH_3, and CO from the CEMS required in Special Condition No. 17, the exhaust emissions from EPN E-CT/HRSG for NO_x, NH_3, and CO in units of pounds/hour shall be calculated on an hourly basis.

B. The hourly calculated values will be cumulatively added during each hour of the month and stored in the computer hard drive and on individually stored disks or other TCEQ-accepted computer media. Records of this information will also be available in a form suitable for inspection.

C. During periods in which the CEMS is unable to produce a valid average concentration, hourly emissions will be calculated from monitoring of operational parameters including the CT and HRSG firing rates, air temperature, steam injection rate, NH_3 injection rate, estimated NH_3 slip, and fuel flow rate.

21. In order to ensure that the CT/HRSG Unit (EPN E-CT/HRSG) and associated air pollution control equipment is operating at optimal conditions, the holder of this permit shall perform and maintain records of the following:

A. During base load operations, when the average NO_x stack outlet concentration increases above 9 ppmv or 15.5 ppmv while firing natural gas or fuel oil, respectively, for more than one hour, the holder of this permit shall investigate and determine the reason for the increase in NO_x concentrations and, if needed, repair the SCR unit and/or its associated equipment as soon as possible. The NO_x concentration shall be corrected to 15 percent O_2. The holder of this permit will take appropriate steps, as necessary, to ensure the SCR unit is operating in compliance with Special Condition Nos. 1 and 5 until repairs can be made.

If the NO_x concentration is greater than those required by Special Condition No. 5 for more than 24 hours, the holder shall notify the TCEQ DFW Regional Office either verbally or with a written report detailing the cause of the increase in emissions and all efforts being made to correct the problem. If the NO_x concentration does not decrease to meet the requirements of Special Condition No. 5 within two weeks of the initial date of increase in NO_x concentrations, the holder shall commence with shutdown procedures.

B. When the average CO stack outlet concentration from increases above 25 ppmv at full load or 240 ppmv at part load or 60 ppmv during power augmentation while firing natural gas or fuel oil, respectively, for more than one hour, the holder of this permit shall investigate and determine the

reason for the increase in CO concentrations and, if needed, repair the HRSG and/or its associated equipment as soon as possible. All concentrations shall be corrected to 15 percent O_2. The holder of this permit will take appropriate steps, as necessary, to ensure the HRSG is operating in compliance with Special Condition Nos. 1 and 5 until repairs can be made.

If the concentration is greater than those required by Special Condition No. 5 for more than 24 hours, the holder shall notify the TCEQ DFW Regional Office either verbally or with a written report, detailing the cause of the increase in emissions and all efforts being made to correct the problem. If the CO concentration does not decrease to meet the requirements of Special Condition No. 5 within two weeks of the initial date of increase in CO concentrations, the holder shall commence with shutdown procedures.

C. When the average NH_3 outlet concentration from the SCR increases above 10 ppmv for more than one hour, the holder of this permit shall investigate and determine the reason for the increase in NH_3 concentrations and, if needed, repair the SCR and/or its associated equipment as soon as possible. The NH_3 concentration shall be corrected to 15 percent O_2. The holder of this permit will take appropriate steps, as necessary, to ensure the SCR unit is operating in compliance with Special Condition Nos. 1 and 9 until repairs can be made.

If the NH_3 concentration is not in compliance with Special Condition No. 9 for more than 24 hours, the holder shall notify the TCEQ DFW Regional Office either verbally or with a written report, detailing the cause of the increase in emissions and all efforts being made to correct the problem. If the NH_3 concentration does not decrease to meet the requirements of Special Condition No. 9 within two weeks of the initial date of increase in NH_3 concentrations, the holder shall commence with shutdown procedures.

22. The holder of this permit shall monitor the fuels fired in the equipment authorized by this permit for fuel-bound sulfur as specified in 40 CFR ' 60.334(b). Any request for a custom monitoring schedule shall be made in writing and directed to the Air Permits Division of the TCEQ although authority for granting such custom schedules remains with the EPA. Any custom schedule approved by EPA pursuant to 40 CFR ' 60.334(b) will be recognized as enforceable conditions of this permit provided that the holder of this permit demonstrates that the conditions of such custom schedule will be adequate to demonstrate continuous compliance with Special Condition Nos. 1 and 3.

Compliance and Maintenance

23. On an annual basis or during routine unit turnarounds, the low-NO_x duct burners of the HRSG shall be visually inspected for erosion, corrosion, plugging, or any other alternation that may adversely affect low-NO_x performance. The TCEQ DFW Regional Office shall be notified at least seven days prior to the inspection in order to be given an opportunity to witness the inspection procedure.

24. A written description of any deviation from the monitoring required herein shall be made available to the

TCEQ prior to the pretest meeting required in Special Condition No. 16. The TCEQ DFW Regional Director or the TCEQ Air Permits Division in Austin, and the EPA in Dallas shall approve or disapprove of any request for an alternate monitoring requirement. Such approval shall be obtained prior to the date required to conduct stack sampling under Special Condition No. 16.

Planned Maintenance Startup and Shutdown (MSS)

25. This permit authorizes the emissions from the planned maintenance, startup, and shutdown (MSS) activities listed in Attachment A, or the MAERT attached to this permit. Attachment A identifies the inherently low emitting (ILE) planned maintenance activities that this permit authorizes to be performed. **(10/11)**

26. The emissions limits that are identified in Special Conditions 5A, 5B and 9 shall not apply during planned MSS activities. **(10/11)**

27. The holder of this permit shall minimize emissions during planned maintenance, start-up and shutdown (MSS) activities by operating the facility and associated air pollution control equipment in accordance with good air pollution control practices, safe operating practices, and protection of the facility. **(10/11)**

28. Emissions during planned startup and shutdown activities will be minimized by limiting the duration of operation in planned startup and shutdown mode as follows: **(10/11)**

    A. A planned startup of the electric generating facility (EGF) with EPN No. E-CT/HRSG is defined as the period that begins when fuel is first fed to the unit and ends when the load on the unit reaches 120 MW. A planned startup for that EGF shall not exceed four hours.

    B. A planned shutdown of the EGF with EPN No. E-CT/HRSG is defined as the period that begins when the load on the unit drops below 120 MW and ends when fuel is no longer fed to the unit. A planned shutdown for that EGF shall not exceed two hours.

29. Compliance with the emissions limits for planned MSS activities identified in the MAERT attached to this permit may be demonstrated as follows. **(10/11)**

    A. For each pollutant emitted during ILE planned maintenance activities, the permit holder shall annually confirm the continued validity of the estimated potential to emit represented in the permit application for all ILE planned maintenance activities. The total emissions from all ILE planned

maintenance activities (See Attachment A) shall be considered to be no more than the estimated potential to emit for those activities that are represented in the permit application.

B. All other maintenance activities may be authorized by 30 TAC § 106.263.

30. With the exception of the emission limits in the MAERT attached to this permit, the permit conditions relating to planned MSS activities do not become effective until 180 days after issuance of the permit amendment that added such conditions. **(10/11)**

Recordkeeping Requirements

31. The following information shall be made and maintained by the holder of this permit in a form suitable for inspection for a period of two years and shall be made immediately available upon request to representatives of the TCEQ, EPA, or any local air pollution control program having jurisdiction:

A. Written records of any accidental releases, spills, or venting of NH_3 and the corrective action taken in accordance with Special Condition Nos. 10 and 11.

B. Written records of maintenance performed to any piping and valves in NH_3 service pursuant to Special Condition No. 12.

C. A complete copy of the testing report and records of the initial performance testing completed pursuant to Special Condition No. 16.

D. Records of the CEMS data required by Special Condition No. 17 to demonstrate continuous compliance with Special Condition No. 5.

E. Records of average hourly fuel and water consumption in the gas turbines pursuant to Special Condition No. 18.

F. Records of any NH_3 emissions calculations or testing performed during CEMS downtime pursuant to Special Condition No. 19

G. Calculations of predicted hourly NO_x, CO, and NH_3 emissions from the HRSG exhaust stacks when required by Special Condition No. 20.

H. Written records of any modifications or maintenance performed upon the equipment authorized by this permit.

I. Raw data files of all CEMS data including calibration checks and adjustments and maintenance performed on these systems of devices in a permanent form suitable for inspection.

J. Records of any maintenance or corrective action taken to maintain SCR performance pursuant to Special Condition No. 21.

K. Records of fuel sampling conducted pursuant to Special Condition No. 22 to demonstrate continuous compliance with Special Condition Nos. 1 and 3.

L. Written records of inspections conducted pursuant to Special Condition No. 23.

M. Field records of quarterly opacity observation as prescribed in 40 CFR 60, Appendix A, Test Method 9. **(10/11)**

N. A log of all startups and shutdowns and durations to demonstrate compliance with Special Condition No. 28. **(10/11)**

Reporting

32. The holder of this permit shall submit to the TCEQ DFW 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. In addition to the information specified in 40 CFR ' 60.7(c), each report shall contain the hours of operation of the facility and a report summary of the periods of noncomplying emissions and CEMS downtimes by cause. Additionally, the report shall contain the duration, cause, and corrective action taken for any accidental release of NH_3.

33. For the purposes of reporting pursuant to Special Condition No. 26, noncomplying emissions from EPN E-CT/HRSG may be defined as follows:

A. Noncomplying emissions of NO_x or CO may be defined as each one-hour period of operation, except during planned MSS (defined as turbine operation at less than 120 MW, not to exceed four hours) during which the average emissions of NO_x or CO, as measured and recorded by the CEMS, exceed the emission limitations of Special Condition No. 5.

B. Noncomplying annual emissions of NO_x may be defined as a rolling 12-month period during which the 12-month cumulative emissions of NO_x exceed the annual limits specified in the table referenced in Special Condition No. 1.

C. Noncomplying emissions of NH_3 may be defined as each one-hour period of operation, except during planned MSS (defined as turbine operation at less than 120 MW, not to exceed four hours) during which the average emissions of NH_3 as measured and recorded by the CEMS, exceed the emission limitations of Special Condition No. 9.

D. For any period of operation except planned MSS during which the CEMS is unable to provide valid hourly emissions, noncomplying emissions of NO_x may be defined as each hourly period for which the predicted emissions of NO_x calculated in Special Condition No. 20 exceeds Special Condition No. 5.

E. For any period of operation except planned MSS during which the CEMS is unable to provide valid hourly emissions, noncomplying emissions of CO may be defined as each hourly period for which the predicted emissions of NO_x calculated in Special Condition No. 20 exceeds Special Condition No. 5.

F. For any period of operation except planned MSS during which the CEMS is unable to provide valid hourly emissions, noncomplying emissions of NH_3 may be defined as:

1. Each hourly period for which the predicted emissions of NH_3 calculated in Special Condition No. 20 that exceeds Special Condition No 1.

2. Any sample of which is found to contain NH_3 in excess of the limits of Special Condition No. 9 or which indicates exceedance of the NH_3 limitation required in Special Condition No. 1.

G. Noncomplying emissions of SO_2 may be defined as fuel which is found to contain sulfur in excess of the limits of Special Condition No. 3 or which indicates exceedance of the SO_2 limitation required in Special Condition No. 1, based on 100 percent conversion of the sulfur in the fuel to SO_2.

Dated October 31, 2011

Attachment A

Permit No. 25384 and PSDTX839

Inherently Low Emitting (ILE) Planned Maintenance Activities

Planned Maintenance Activity	Emissions NH_3	VOC	NO_x	CO	PM	SO_2
Gaseous Venting and Line Purging	x	x				
Miscellaneous particulate filter maintenance[1]					x	
CEMS Calibration	x		x	x		
Small Equipment Maintenance – Low Vapor Pressure VOC		x				
Sludge Management[2]		x				

Notes:

1. Includes, but is not limited to filters, process-related building air filters, and combustion turbine air intake filters.
2. Includes, but is not limited to, management by vacuum truck/dewatering of materials in sumps, tanks and other closed or open vessels. Materials managed include water and sludge mixtures containing miscellaneous VOCs such as diesel, lube oil, and other waste oils.

Headers

Special Conditions

Permit Numbers 25384 and PSDTX839

Page

ATTACHMENT C

1. Top of document
    1. For each pollutant emitted during ILE planned maintenance activities, the permit holder shall annually confirm the continued validity of the estimated potential to emit represented in the permit application for all ILE planned maintenance activities. The total emissions from all ILE planned maintenance activities (See Attachment A) shall be considered to be no more than the estimated potential to emit for those activities that are represented in the permit application.
    2. All other maintenance activities may be authorized by 30 TAC § 106.263.

Section 1 - Document

Special Conditions

Permit Numbers 25384 and PSDTX839

Emission Limitations and Operating Specifications

1. This permit covers only those sources of emissions listed in the attached table entitled AEmission Sources - Maximum Allowable Emission Rates,@ and those sources are limited to the emission limits and other conditions specified in the attached table. The annual rates are based on a rolling 12-month period.

2. A copy of this permit, the June 1994 permit application, and any subsequent permit-related correspondence shall be kept at the plant site and made available at the request of personnel from the Texas Commission on Environmental Quality (TCEQ) or the local air pollution control agency. In addition, the holder of this permit shall maintain an updated site arrangement of the facility showing the location and emission point numbers (EPNs) for all sources listed on the maximum allowable emission rates table (MAERT).

3. Fuel fired in the Westinghouse Model W501F Gas Combustion Turbine (CT) and the duct burner of the heat recovery steam generator (HRSG) are limited as follows:

    A. Fuels fired in the CT:

        1. Primary fuel - pipeline-quality, sweet natural gas containing no more than 5.0 grains total sulfur and 0.25 grain of hydrogen sulfide (H_2S) per 100 dry standard cubic feet (dscf).

        2. Backup fuel - refinery-grade, first-run distillate fuel oil containing no more than 0.05 percent

sulfur by weight. Fuel oil may be fired as a backup fuel for a maximum of 720 hours per year. The permit holder must show compliance with the 720 hour limit on a rolling 12-month average.

B. Fuel fired in the HRSG duct burner is limited to pipeline-quality, sweet natural gas containing no more than 5.0 grains total sulfur and 0.25 grain of H_2S per 100 dscf.

4. The permit holder shall use steam injection to control the emissions contribution of nitrogen oxides (NO_x) from the CT prior to entering the HRSG and selective catalytic reduction (SCR) units.

5. The stack gases of the CT/HRSG Unit (EPN E-CT/HRSG) shall not exceed the emission concentrations stated below.

A. While the CT/HRSG unit is firing natural gas at base load, the concentration of NO_x and carbon monoxide (CO) in the stack gases of EPN E-CT/HRSG shall not exceed 9 parts per million by volume on a dry basis (ppmvd) and 25 ppmvd, respectively, when corrected to 15 percent oxygen (O_2). Base load operation shall be defined as operation equal to or greater than 162 megawatts (MW). **(2/12)**

B. While the CT is firing fuel oil and the HRSG is firing natural gas, each at base load, the concentration of NO_x and CO in the stack gases of EPN E-CT/HRSG shall not exceed 15.5 ppmvd and 25 ppmvd, respectively, when corrected to 15 percent O_2.

C. Reduced load operation (defined as operation at less than 162 MW) not associated with startup or shutdown is authorized provided the maximum pounds per hour (lb/hr) emissions rates specified in the MAERT are not exceeded. **(2/12)**

6. The HRSG duct burner is limited to a maximum heat input capacity of 375 million British thermal units per hour (MMBtu/hr). The heat input shall be calculated on the higher heating value (HHV) of the fuel.

7. Upon request by the Director of the TCEQ Dallas/Fort Worth (DFW) Regional Office or the Executive Director of the TCEQ or any local air pollution control program having jurisdiction, the holder of this permit shall provide a sample and/or an analysis of the fuel fired in this facility or shall allow air pollution control agency representatives to obtain a sample for analysis.

8. Except during maintenance, startup and shutdown (MSS) activities, the opacity shall not exceed five percent averaged over a six-minute period from each stack or vent. During periods when the CT is firing fuel oil, the opacity limitation shall be 10 percent. During MSS activities, the opacity shall not exceed 15 percent (or other applicable opacity limit specified in Title 30 Texas Administrative Code (TAC) § 111.111(a)(1)). Each determination shall be made by first observing for visible emissions while each facility is in operation. Observations shall be made at least 15 feet and no more than 0.25 miles from the emission point. If visible emissions are observed from an emission point, then the opacity shall be determined and documented within 24 hours for that emission point using Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60), Appendix A, Test Method 9. Contributions from uncombined water shall not be included in determining compliance with this condition. Observations shall be performed and recorded quarterly. If the opacity exceeds five percent during normal operations, 10 percent when firing fuel oil, or 15 percent during MSS activities, corrective action to eliminate the source of visible emissions shall be taken promptly and documented within one week of first observation. **(10/11)**

Anhydrous Ammonia (NH_3)

9. The concentration of NH_3 in the exhaust gases of the EPN E-CT/HRSG shall not exceed 10 parts per million by volume (ppmv) when corrected to 15 percent O_2.

10. The permit holder shall maintain a quantity of no more than 12,000 gallons of NH_3 on-site at any time. Additionally, the permit holder shall maintain prevention and protection measures for the NH_3 storage system as represented in Table 4-1 of the supplemental letter dated August 22, 1994, submitted during the review of the June 1994 application for this permit. The letter includes the following:

    A. Relief valves shall be discharged to the HRSG Stack (EPN E-CT/HRSG) rather than releasing directly to the atmosphere at ground level.

    B. The tank area will be diked so as to contain at least the volume of the pressure vessel.

    C. A water deluge system shall be installed to cover the tank and diked area to mitigate any airborne releases of NH_3. The water deluge system must activate when a level of 200 ppmv of NH_3 is detected.

    D. Any NH_3 solution contained by the dike area shall be immediately transported to a safe disposal area.

11. In the event of a release of the NH_3 from the liquid fill line, pressure vessel due to overpressurization, process line to the SCR system, or the vapor return lines from the vaporizer or any other accidental release of NH_3, the permit holder shall follow the contingency plan and mitigation procedures set out in Sections 5.0 and 6.0 of the August 22, 1994 letter regarding the use of NH_3.

12. In addition to the requirements of Special Condition Nos. 10 and 11, the permit holder shall maintain the piping and valves in NH_3 service as follows:

    A. All operating practices and procedures relating to the handling and storage of NH_3 shall conform to the safety recommendations specified for that compound by guidelines of the American National Standards Institute and the Compressed Gas Association.

    B. Audio, olfactory, and visual checks for NH_3 leaks within the operating area shall be made every four hours.

    C. Immediately, but no later than one hour upon the detection of a leak, plant personnel shall take the following actions:

        1. Locate and isolate the leak, if necessary.

        2. Commence repair or replacement of the leaking component.

        3. Use a leak collection/containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

13. All necessary plant employees shall undergo proper training in the maintenance, mitigation, and contingency procedures necessary to prevent, control, or handle accidental releases of NH_3.

Federal Applicability

14. These facilities shall comply with applicable requirements of the EPA regulations on Standards of Performance for New Stationary Sources, 40 CFR Part 60, promulgated for:

    A. General Conditions, Subpart A.

    B. The heat recovery steam generator is subject to the requirements of Subpart Da, Standards of Performance for Electric Utility Steam Generating Units.

    C. The Westinghouse Model W501F Gas Turbine is subject to the requirements of Subpart GG, Standards of Performance for Stationary Gas Turbines.

    If any condition of this permit is more stringent than the regulations so incorporated, then for the purposes of complying with this permit, the permit shall govern and be the standard by which compliance shall be demonstrated.

Initial Determination of Compliance

15. Sampling ports and platforms shall be incorporated into the design of the HRSG exhaust stacks according to the specifications set forth in the attachment entitled AChapter 2, Stack Sampling Facilities.@ Alternate sampling facility designs may be submitted for approval by the TCEQ DFW Regional Director or the TCEQ Air Permits Division.

16. The holder of this permit shall perform stack sampling and other testing as required to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from EPN E-CT/HRSG. Sampling shall be conducted in accordance with the appropriate procedures of the TCEQ Sampling Procedures Manual and in accordance with the appropriate EPA Reference Methods for NO_x, CO, volatile organic compounds (VOC), sulfur dioxide (SO_2), NH_3, particulate matter less than 10 microns in diameter (PM_{10}), and opacity.

    Fuel sampling using the methods and procedures of 40 CFR ' 60.335(d) may be conducted in lieu of stack sampling for SO_2. If fuel sampling is used, compliance with New Source Performance Standards (NSPS) Subpart GG, SO_2 limits shall be based on 100 percent conversion of the sulfur in the fuel to SO_2. Any deviations from those procedures must be approved by the TCEQ Air Permits Division or the TCEQ DFW Regional Director prior to sampling. The TCEQ Executive Director or his designated representative shall be afforded the opportunity to observe all such sampling.

    The holder of this permit is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense.

A. The TCEQ DFW Regional Office shall be contacted as soon as testing is scheduled but not less than 45 days prior to sampling to schedule a pretest meeting.

The notice shall include:

1. Date for pretest meeting.

2. Date sampling will occur.

3. Name of firm conducting sampling.

4. Type of sampling equipment to be used.

5. Method or procedure to be used in sampling.

6. Procedure used to determine turbine loads during and after the sampling period.

7. A plan to develop computer-generated calculations of NO_x and CO emissions in pounds per hour and tons per rolling 12-month period. The plan shall include the equations used to convert the monitored concentrations to mass emission rates. The computer calculated hourly values are to be generated and compared to the initial stack sampling results to demonstrate the relative accuracy of the computer-generated output.

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. A written proposed description of any deviation from sampling procedures specified in permit conditions, TCEQ, or EPA sampling procedures shall be made available to the TCEQ prior to the pretest meeting. The TCEQ DFW Regional Director or the TCEQ Air Permits Division shall approve or disapprove of any deviation from specified sampling procedures. Requests to waive testing for any pollutant specified in this condition shall be submitted to the TCEQ Office Air, Air Permits Division. Test waivers and alternate/equivalent procedure proposals for NSPS testing which must have EPA approval shall be submitted to the TCEQ Air Permits Division in Austin.

B. Air contaminants emitted from the CT/HRSG unit to be tested for include (but are not limited to) NO_x, CO, SO_2, VOC, PM_{10}, NH_3, O_2, and opacity. The CT shall be tested at a minimum of four points in the normal operating range including full load for the atmospheric conditions which exist during testing while firing natural gas and fuel oil. The HRSG duct burners shall be tested at the

maximum firing rate of 450 MMBtu/hr (HHV) while firing natural gas.

C. Sampling shall occur within 60 days after achieving the maximum production rate at which the facility will be operated but no later than 180 days after initial start-up. The TCEQ and EPA may require additional sampling at other times as they deem appropriate.

D. Within 60 days after the completion of the testing and sampling required herein, copies of the sampling report shall be distributed as follows.

One copy to the TCEQ DFW Regional Office.

One copy to the TCEQ Office of Air.

One copy to the EPA Region 6 in Dallas.

Continuous Determination of Compliance

17. The holder of this permit shall install, calibrate, maintain, and operate a continuous emission monitoring system (CEMS) to:

A. Measure and record the concentrations of NO_x, CO, NH_3, and O_2 at the CT/HRSG exhaust stack. The NO_x and CO concentrations shall be corrected and reported in accordance with Special Condition No. 5. The NH_3 concentrations shall be corrected and reported in accordance with Special Condition No. 9.

B. The CEMS required in Special Condition No. 17A shall comply with the following requirements:

1. The CEMS shall 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 60, Appendix B. The Performance Specification tests shall be conducted during the sampling required by Special Condition No. 16, and written copies of the results shall be submitted within 60 days of completion of the tests to the TCEQ DFW Regional Office and the Air Enforcement Branch of EPA in Dallas.

2. The system shall be zeroed and spanned daily and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in 40 CFR Part 60, Appendix B. Each

gaseous monitor shall be quality-assured at least quarterly using cylinder gas audits (CGA). The CGA method to be used is contained in 40 CFR Part 60, Appendix F, Procedure 1, ' 5.1.2. An equivalent method approved by the EPA and TCEQ may be used.

3. The gaseous monitoring data shall be reduced to hourly average concentrations at least once every day, using a minimum of four equally-spaced data points from each one-hour period. Two valid data points shall be generated during the hourly period in which zero and span is performed.

4. The CEMS shall demonstrate 90 percent monitor data availability on a monthly basis. The percent monitor data availability shall be calculated as the total unit operating hours for which quality-assured data was recorded divided by the total unit operating hours.

5. All CGA exceedances greater than "15 percent accuracy and any unscheduled CEMS downtime shall be reported to the TCEQ DFW Regional Office and the Air Enforcement Branch of EPA in Dallas, and necessary corrective action shall be taken. Unscheduled CEMS downtime is any CEMS downtime not required for daily zero and span checks, quarterly CGAs, and annual relative accuracy test audits. Supplemental stack concentration measurements may be required at the discretion of the TCEQ DFW Regional Director or the EPA.

6. The CEMS shall demonstrate an annual system reliability of at least 90 percent (downtime does not include daily zero and span measurement time or cogeneration unit downtime) or options to increase system reliability to an acceptable value, including a redundant CEMS, may be required by the TCEQ DFW Regional Director.

7. For NSPS sources subject to Appendix F, the TCEQ DFW Regional Office and EPA NSRS in Dallas shall be notified at least 30 days prior to each annual relative accuracy testing audit in order to provide them the opportunity to observe the testing.

18. The holder of this permit shall additionally install, calibrate, maintain, and operate continuous monitoring systems to monitor and record the average hourly fuel and water consumption in the gas turbines. The systems shall be accurate to "5.0 percent, and the system shall be approved by the Air Permits Division of the TCEQ prior to conducting the initial compliance demonstration required by Special Condition No. 16.

19. If the NH_3 CEMS is not able to show continuous demonstration of compliance, then the facility shall implement wet chemical sampling or an alternative TCEQ-approved method of estimating NH_3 emissions. The holder of this permit shall monitor NH_3 concentration (ppmv) and stack gas flow rate in

standard cubic feet per minute in the SCR unit exhaust stack. The measured NH_3 concentration and flow rate shall be used to calculate the NH_3 emission rate in pounds per hour and cumulative tons per year to determine compliance with Special Condition Nos. 1 and 9.

20. The holder of this permit shall develop a program to calculate the total mass flow rate through each cogeneration train by using a mass balance of fuel, steam, and ammonia into the CT/HRSG unit and exhaust flow out of the HRSG stack to ensure continuous compliance with Special Condition No. 5.

    A. Using the calculated flow rate and the concentrations of NO_x, NH_3, and CO from the CEMS required in Special Condition No. 17, the exhaust emissions from EPN E-CT/HRSG for NO_x, NH_3, and CO in units of pounds/hour shall be calculated on an hourly basis.

    B. The hourly calculated values will be cumulatively added during each hour of the month and stored in the computer hard drive and on individually stored disks or other TCEQ-accepted computer media. Records of this information will also be available in a form suitable for inspection.

    C. During periods in which the CEMS is unable to produce a valid average concentration, hourly emissions will be calculated from monitoring of operational parameters including the CT and HRSG firing rates, air temperature, steam injection rate, NH_3 injection rate, estimated NH_3 slip, and fuel flow rate.

21. In order to ensure that the CT/HRSG Unit (EPN E-CT/HRSG) and associated air pollution control equipment is operating at optimal conditions, the holder of this permit shall perform and maintain records of the following:

    A. During base load operations, when the average NO_x stack outlet concentration increases above 9 ppmv or 15.5 ppmv while firing natural gas or fuel oil, respectively, for more than one hour, the holder of this permit shall investigate and determine the reason for the increase in NO_x concentrations and, if needed, repair the SCR unit and/or its associated equipment as soon as possible. The NO_x concentration shall be corrected to 15 percent O_2. The holder of this permit will take appropriate steps, as necessary, to ensure the SCR unit is operating in compliance with Special Condition Nos. 1 and 5 until repairs can be made.

If the NO_x concentration is greater than those required by Special Condition No. 5 for more than 24 hours, the holder shall notify the TCEQ DFW Regional Office either verbally or with a written report detailing the cause of the increase in emissions and all efforts being made to correct the problem. If the

NO_x concentration does not decrease to meet the requirements of Special Condition No. 5 within two weeks of the initial date of increase in NO_x concentrations, the holder shall commence with shutdown procedures.

B. When the average CO stack outlet concentration increases above 25 ppmv at base load or 240 ppmv at reduced load or 60 ppmv during power augmentation while firing natural gas or fuel oil, respectively, for more than one hour, the holder of this permit shall investigate and determine the reason for the increase in CO concentrations and, if needed, repair the HRSG and/or its associated equipment as soon as possible. All concentrations shall be corrected to 15 percent O_2. The holder of this permit will take appropriate steps, as necessary, to ensure the HRSG is operating in compliance with Special Condition Nos. 1 and 5 until repairs can be made. **(2/12)**

If the concentration is greater than those required by Special Condition No. 5 for more than 24 hours, the holder shall notify the TCEQ DFW Regional Office either verbally or with a written report, detailing the cause of the increase in emissions and all efforts being made to correct the problem. If the CO concentration does not decrease to meet the requirements of Special Condition No. 5 within two weeks of the initial date of increase in CO concentrations, the holder shall commence with shutdown procedures.

C. When the average NH_3 outlet concentration from the SCR increases above 10 ppmv for more than one hour, the holder of this permit shall investigate and determine the reason for the increase in NH_3 concentrations and, if needed, repair the SCR and/or its associated equipment as soon as possible. The NH_3 concentration shall be corrected to 15 percent O_2. The holder of this permit will take appropriate steps, as necessary, to ensure the SCR unit is operating in compliance with Special Condition Nos. 1 and 9 until repairs can be made.

If the NH_3 concentration is not in compliance with Special Condition No. 9 for more than 24 hours, the holder shall notify the TCEQ DFW Regional Office either verbally or with a written report, detailing the cause of the increase in emissions and all efforts being made to correct the problem. If the NH_3 concentration does not decrease to meet the requirements of Special Condition No. 9 within two weeks of the initial date of increase in NH_3 concentrations, the holder shall commence with shutdown procedures.

22. The holder of this permit shall monitor the fuels fired in the equipment authorized by this permit for fuel-bound sulfur as specified in 40 CFR ' 60.334(b). Any request for a custom monitoring schedule shall be made in writing and directed to the Air Permits Division of the TCEQ although authority for granting such custom schedules remains with the EPA. Any custom schedule approved by EPA pursuant to 40 CFR ' 60.334(b) will be recognized as enforceable conditions of this permit provided that the holder of this permit demonstrates that the conditions of such custom schedule will be adequate to demonstrate continuous compliance with Special Condition Nos. 1 and 3.

Compliance and Maintenance

23. On an annual basis or during routine unit turnarounds, the low-NO_x duct burners of the HRSG shall be

visually inspected for erosion, corrosion, plugging, or any other alternation that may adversely affect low-NO_x performance. The TCEQ DFW Regional Office shall be notified at least seven days prior to the inspection in order to be given an opportunity to witness the inspection procedure.

24. A written description of any deviation from the monitoring required herein shall be made available to the TCEQ prior to the pretest meeting required in Special Condition No. 16. The TCEQ DFW Regional Director or the TCEQ Air Permits Division in Austin, and the EPA in Dallas shall approve or disapprove of any request for an alternate monitoring requirement. Such approval shall be obtained prior to the date required to conduct stack sampling under Special Condition No. 16.

Planned Maintenance, Startup, and Shutdown (MSS)

25. This permit authorizes the emissions from the planned MSS activities listed in Attachment A, or the MAERT attached to this permit. Attachment A identifies the inherently low emitting (ILE) planned maintenance activities that this permit authorizes to be performed. **(10/11)**

26. The emissions limits that are identified in Special Conditions 5A, 5B and 9 shall not apply during planned MSS activities. **(10/11)**

27. The holder of this permit shall minimize emissions during planned MSS activities by operating the facility and associated air pollution control equipment in accordance with good air pollution control practices, safe operating practices, and protection of the facility. **(10/11)**

28. Emissions during planned startup and shutdown activities will be minimized by limiting the duration of operation in planned startup and shutdown mode as follows: **(10/11)**

    A. A planned startup of the electric generating facility (EGF) with EPN No. E-CT/HRSG is defined as the period that begins when fuel is first fed to the unit and ends when the load on the unit reaches 120 MW. A planned startup for that EGF shall not exceed four hours.

    B. A planned shutdown of the EGF with EPN No. E-CT/HRSG is defined as the period that begins when the load on the unit drops below 120 MW and ends when fuel is no longer fed to the unit. A planned shutdown for that EGF shall not exceed two hours.

29. Compliance with the emissions limits for planned MSS activities identified in the MAERT attached to this permit may be demonstrated as follows. **(10/11)**

A. For each pollutant emitted during ILE planned maintenance activities, the permit holder shall annually confirm the continued validity of the estimated potential to emit represented in the permit application for all ILE planned maintenance activities. The total emissions from all ILE planned maintenance activities (See Attachment A) shall be considered to be no more than the estimated potential to emit for those activities that are represented in the permit application.

B. All other maintenance activities may be authorized by 30 TAC § 106.263.

30. With the exception of the emission limits in the MAERT attached to this permit, the permit conditions relating to planned MSS activities do not become effective until April 28, 2012. **(10/11)**

Recordkeeping Requirements

31. The following information shall be made and maintained by the holder of this permit in a form suitable for inspection for a period of two years and shall be made immediately available upon request to representatives of the TCEQ, EPA, or any local air pollution control program having jurisdiction:

A. Written records of any accidental releases, spills, or venting of NH_3 and the corrective action taken in accordance with Special Condition Nos. 10 and 11.

B. Written records of maintenance performed to any piping and valves in NH_3 service pursuant to Special Condition No. 12.

C. A complete copy of the testing report and records of the initial performance testing completed pursuant to Special Condition No. 16.

D. Records of the CEMS data required by Special Condition No. 17 to demonstrate continuous compliance with Special Condition No. 5.

E. Records of average hourly fuel and water consumption in the gas turbines pursuant to Special Condition No. 18.

F. Records of any NH_3 emissions calculations or testing performed during CEMS downtime pursuant to Special Condition No. 19

G. Calculations of predicted hourly NO_x, CO, and NH_3 emissions from the HRSG exhaust stacks when required by Special Condition No. 20.

H. Written records of any modifications or maintenance performed upon the equipment authorized by this permit.

I. Raw data files of all CEMS data including calibration checks and adjustments and maintenance performed on these systems of devices in a permanent form suitable for inspection.

J. Records of any maintenance or corrective action taken to maintain SCR performance pursuant to Special Condition No. 21.

K. Records of fuel sampling conducted pursuant to Special Condition No. 22 to demonstrate continuous compliance with Special Condition Nos. 1 and 3.

L. Written records of inspections conducted pursuant to Special Condition No. 23.

M. Field records of quarterly visible emission observations and opacity measurements (if applicable) as required by Special Condition No. 8. **(2/12)**

N. A log of all startups and shutdowns and durations to demonstrate compliance with Special Condition No. 28. **(10/11)**

Reporting

32. The holder of this permit shall submit to the TCEQ DFW 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. In addition to the information specified in 40 CFR ' 60.7(c), each report shall contain the hours of operation of the facility and a report summary of the periods of noncomplying emissions and CEMS downtimes by cause. Additionally, the report shall contain the duration, cause, and corrective action taken for any accidental release of NH_3.

33. For the purposes of reporting pursuant to Special Condition No. 32, noncomplying emissions from EPN E-CT/HRSG may be defined as follows:

A. Noncomplying emissions of NO_x or CO may be defined as each one-hour period of operation, except during planned MSS (defined as turbine operation at less than 120 MW, not to exceed four hours) during which the average emissions of NO_x or CO, as measured and recorded by the CEMS, exceed the emission limitations of Special Condition No. 5.

B. Noncomplying annual emissions of NO_x may be defined as a rolling 12-month period during which the 12-month cumulative emissions of NO_x exceed the annual limits specified in the table referenced in Special Condition No. 1.

C. Noncomplying emissions of NH_3 may be defined as each one-hour period of operation, except during planned MSS (defined as turbine operation at less than 120 MW, not to exceed four hours) during which the average emissions of NH_3 as measured and recorded by the CEMS, exceed the emission limitations of Special Condition No. 9.

D. For any period of operation except planned MSS during which the CEMS is unable to provide valid hourly emissions, noncomplying emissions of NO_x may be defined as each hourly period for which the predicted emissions of NO_x calculated in Special Condition No. 20 exceeds Special Condition No. 5.

E. For any period of operation except planned MSS during which the CEMS is unable to provide valid hourly emissions, noncomplying emissions of CO may be defined as each hourly period for which the predicted emissions of NO_x calculated in Special Condition No. 20 exceeds Special Condition No. 5.

F. For any period of operation except planned MSS during which the CEMS is unable to provide valid hourly emissions, noncomplying emissions of NH_3 may be defined as:

1. Each hourly period for which the predicted emissions of NH_3 calculated in Special Condition No. 20 that exceeds Special Condition No 1.

2. Any sample of which is found to contain NH_3 in excess of the limits of Special Condition

No. 9 or which indicates exceedance of the NH_3 limitation required in Special Condition No. 1.

G. Noncomplying emissions of SO_2 may be defined as fuel which is found to contain sulfur in excess of the limits of Special Condition No. 3 or which indicates exceedance of the SO_2 limitation required in Special Condition No. 1, based on 100 percent conversion of the sulfur in the fuel to SO_2.

Dated February 13, 2012

Attachment A

Permit No. 25384 and PSDTX839

Inherently Low Emitting (ILE) Planned Maintenance Activities

Planned Maintenance Activity	Emissions NH_3	VOC	NO_x	CO	PM	SO_2
Gaseous Venting and Line Purging	x	x				
Miscellaneous particulate filter maintenance[1]					x	
CEMS Calibration	x		x	x		
Small Equipment Maintenance – Low Vapor Pressure VOC		x				
Sludge Management[2]		x				

Notes:

1. Includes, but is not limited to filters, process-related building air filters, and combustion turbine air intake filters.
2. Includes, but is not limited to, management by vacuum truck/dewatering of materials in sumps, tanks and other closed or open vessels. Materials managed include water and sludge mixtures containing miscellaneous VOCs such as diesel, lube oil, and other waste oils.

Headers

Special Conditions

Permit Numbers 25384 and PSDTX839

Page

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ATTACHMENT D

Bryan W. Shaw, Ph.D., *Chairman*
Carlos Rubinstein, *Commissioner*
Toby Baker, *Commissioner*
Zak Covar, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

May 15, 2012

MR MARK PAVELKA
MANAGER ENGINEERING SERVICES
BRAZOS ELECTRIC POWER COOPERATIVE, INC.
2404 LA SALLE AVE
WACO TX 76706-3928

Re: Effective Federal Operating Permit and Acid Rain Permit Approval
Renewal
Permit Number: O543
Brazos Electric Power Cooperative, Inc.
Johnson County Generation Facility
Cleborne, Johnson County
Regulated Entity Number: RN100223312
Customer Reference Number: CN600128821
Account Number: JH-0230-L

Dear Mr. Pavelka:

The effective federal operating permit (FOP) and acid rain permit for Brazos Electric Power Cooperative, Inc., Johnson County Generation Facility is enclosed. This FOP constitutes authority to operate the emission units identified in the FOP application.

All site operating permits are subject to public petition for 60 days following the expiration of the 45-day U.S. Environmental Protection Agency (EPA) review. The public petition period for the FOP extends from May 5, 2012 until July 3, 2012. If the EPA receives a valid petition and objects to the above-referenced permit, you will be notified promptly by the Texas Commission on Environmental Quality (TCEQ).

It should be noted that from the date of this letter Brazos Electric Power Cooperative, Inc., Johnson County Generation Facility must operate in accordance with the requirements of Title 30 Texas Administrative Code Chapter 122 (30 TAC Chapter 122) and the FOP. Some of the terms and conditions contained in the FOP include recordkeeping conditions, reporting conditions (which includes deviation reporting), and compliance certification conditions. All reports, along with any questions regarding the reports, shall be forwarded to the Texas Commission on Environmental Quality, Dallas/Fort Worth Regional Office, 2309 Gravel Drive, Fort Worth, Texas 76118-6951.

Consistent with 30 TAC Chapter 122, Subchapter C, the permit holder shall submit an application to the Air Permits Division (APD) for a revision to an FOP for those activities at a site which change, add, or remove one or more FOP terms or conditions. The permit holder shall also submit an application to the APD for a revision to a permit to address the following: the adoption of an applicable requirement previously designated as federally enforceable only;

the promulgation of a new applicable requirement; the adoption of a new state-only requirement; or a change in a state-only designation.

Thank you again for your cooperation in this matter. If you have questions concerning the review or this notice, please contact Ms. Camilla Widenhofer at (512) 239-1028.

This action is taken under authority delegated by the Executive Director of the TCEQ.

Sincerely,

Michael Wilson, P.E., Director
Air Permits Division
Office of Air
Texas Commission on Environmental Quality

MPW/cw

cc: Mr. Mickey Green, Environmental Specialist, Brazos Electric Power Cooperative, Inc., Waco
Mr. Mike Meyers, Environmental Manager, Brazos Electric Power Cooperative, Inc., Waco
Air Section Manager, Region 4 - Fort Worth

Enclosure: Effective Permit

cc: Air Permit Section Chief, U.S. Environmental Protection Agency, Region 6, Dallas

Project Number: 17151

FEDERAL OPERATING PERMIT

A FEDERAL OPERATING PERMIT IS HEREBY ISSUED TO

Brazos Electric Power Cooperative, Inc.

AUTHORIZING THE OPERATION OF

Johnson County Generation Facility
Electric Services

LOCATED AT

Johnson County, Texas

Latitude 32° 23' 57" Longitude 097° 24' 29"

Regulated Entity Number: RN100223312

This permit is issued in accordance with and subject to the Texas Clean Air Act (TCAA), Chapter 382 of the Texas Health and Safety Code and Title 30 Texas Administrative Code Chapter 122 (30 TAC Chapter 122), Federal Operating Permits. Under 30 TAC Chapter 122, this permit constitutes the permit holder's authority to operate the site, emission units and affected source listed in this permit. Operations of the site, emission units and affected source listed in this permit are subject to all additional rules or amended rules and orders of the Commission pursuant to the TCAA.

This permit does not relieve the permit holder from the responsibility of obtaining New Source Review authorization for new, modified, or existing facilities in accordance with 30 TAC Chapter 116, Control of Air Pollution by Permits for New Construction or Modification.

The site, emission units and affected source authorized by this permit shall be operated in accordance with 30 TAC Chapter 122, the general terms and conditions, special terms and conditions, and attachments contained herein.

This permit shall expire five years from the date of issuance. The renewal requirements specified in 30 TAC § 122.241 must be satisfied in order to renew the authorization to operate the site, emission units and affected source.

Permit No: O543 Issuance Date: May 15, 2012

For the Commission

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General Terms and Conditions

The permit holder shall comply with all terms and conditions contained in 30 TAC § 122.143 (General Terms and Conditions), 30 TAC § 122.144 (Recordkeeping Terms and Conditions), 30 TAC § 122.145 (Reporting Terms and Conditions), and 30 TAC § 122.146 (Compliance Certification Terms and Conditions).

In accordance with 30 TAC § 122.144(1), records of required monitoring data and support information required by this permit, or any applicable requirement codified in this permit, are required to be maintained for a period of five years from the date of the monitoring report, sample, or application unless a longer data retention period is specified in an applicable requirement. The five year record retention period supersedes any less stringent retention requirement that may be specified in a condition of a permit identified in the New Source Review Authorization attachment.

If the permit holder chooses to demonstrate that this permit is no longer required, a written request to void this permit shall be submitted to the Texas Commission on Environmental Quality (TCEQ) by the Responsible Official in accordance with 30 TAC § 122.161(e). The permit holder shall comply with the permit's requirements, including compliance certification and deviation reporting, until notified by the TCEQ that this permit is voided.

The permit holder shall comply with 30 TAC Chapter 116 by obtaining a New Source Review authorization prior to new construction or modification of emission units located in the area covered by this permit.

All reports required by this permit must include in the submittal a cover letter which identifies the following information: company name, TCEQ regulated entity number, air account number (if assigned), site name, area name (if applicable), and Air Permits Division permit number(s).

Special Terms and Conditions:
Emission Limitations and Standards, Monitoring and Testing, and Recordkeeping and Reporting

1. Permit holder shall comply with the following requirements:

    A. Emission units (including groups and processes) in the Applicable Requirements Summary attachment shall meet the limitations, standards, equipment specifications, monitoring, recordkeeping, reporting, testing, and other requirements listed in the Applicable Requirements Summary attachment to assure compliance with the permit.

    B. The textual description in the column titled "Textual Description" in the Applicable Requirements Summary attachment is not enforceable and is not deemed as a substitute for the actual regulatory language. The Textual Description is provided for information purposes only.

C. A citation listed on the Applicable Requirements Summary attachment, which has a notation [G] listed before it, shall include the referenced section and subsection for all commission rules, or paragraphs for all federal and state regulations and all subordinate paragraphs, subparagraphs and clauses, subclauses, and items contained within the referenced citation as applicable requirements.

D. When a grouped citation, notated with a [G] in the Applicable Requirements Summary, contains multiple compliance options, the permit holder must keep records of when each compliance option was used.

E. The permit holder shall comply with the applicable requirements of 40 CFR Part 63, Subpart ZZZZ as identified in the attached Applicable Requirements Summary by October 19, 2013.

2. The permit holder shall comply with the following sections of 30 TAC Chapter 101 (General Air Quality Rules):

A. Title 30 TAC § 101.1 (relating to Definitions), insofar as the terms defined in this section are used to define the terms used in other applicable requirements

B. Title 30 TAC § 101.3 (relating to Circumvention)

C. Title 30 TAC § 101.8 (relating to Sampling), if such action has been requested by the TCEQ

D. Title 30 TAC § 101.9 (relating to Sampling Ports), if such action has been requested by the TCEQ

E. Title 30 TAC § 101.10 (relating to Emissions Inventory Requirements)

F. Title 30 TAC § 101.201 (relating to Emission Event Reporting and Recordkeeping Requirements)

G. Title 30 TAC § 101.211 (relating to Scheduled Maintenance, Start-up, and Shutdown Reporting and Recordkeeping Requirements)

H. Title 30 TAC § 101.221 (relating to Operational Requirements)

I. Title 30 TAC § 101.222 (relating to Demonstrations)

J. Title 30 TAC § 101.223 (relating to Actions to Reduce Excessive Emissions)

3. Permit holder shall comply with the following requirements of 30 TAC Chapter 111:

A. Visible emissions from stationary vents with a flow rate of less than 100,000 actual cubic feet per minute and constructed after January 31, 1972 that are not listed in the Applicable Requirements Summary attachment for 30 TAC Chapter 111, Subchapter A, Division 1 , shall not exceed 20% opacity averaged

over a six-minute period. The permit holder shall comply with the following requirements for stationary vents at the site subject to this standard:

(i) Title 30 TAC § 111.111(a)(1)(B) (relating to Requirements for Specified Sources)

(ii) Title 30 TAC § 111.111(a)(1)(E)

(iii) Title 30 TAC § 111.111(a)(1)(F)(i), (ii), (iii), or (iv)

(iv) For emission units with vent emissions subject to 30 TAC § 111.111(a)(1)(B), complying with 30 TAC § 111.111(a)(1)(F)(ii), (iii), or (iv), and capable of producing visible emissions from, but not limited to, particulate matter, acid gases and NO_x, the permit holder shall also comply with the following periodic monitoring requirements for the purpose of annual compliance certification under 30 TAC § 122.146. These periodic monitoring requirements do not apply to vents that are not capable of producing visible emissions such as vents that emit only colorless VOCs; vents from non-fuming liquids; vents that provide passive ventilation, such as plumbing vents; or vent emissions from any other source that does not obstruct the transmission of light. Vents, as specified in the "Applicable Requirements Summary" attachment, that are subject to the emission limitation of 30 TAC § 111.111(a)(1)(B) and Compliance Assurance Monitoring (CAM), are not subject to the following periodic monitoring requirements and shall comply with the CAM requirements in the "Additional Monitoring Requirements" attachment:

(1) An observation of stationary vents from emission units in operation shall be conducted at least once during each calendar quarter unless the emission unit is not operating for the entire quarter.

(2) For stationary vents from a combustion source, if an alternative to the normally fired fuel is fired for a period greater than or equal to 24 consecutive hours, the permit holder shall conduct an observation of the stationary vent for each such period to determine if visible emissions are present. If such period is greater than 3 months, observations shall be conducted once during each quarter. Supplementing the normally fired fuel with natural gas or fuel gas to increase the net heating value to the minimum required value does not constitute creation of an alternative fuel.

(3) Records of all observations shall be maintained.

(4) Visible emissions observations of emission units operated during daylight hours shall be conducted no earlier than one hour after sunrise and no later than one hour before sunset. Visible emissions

observations of emission units operated only at night must be made with additional lighting and the temporary installation of contrasting backgrounds. Visible emissions observations shall be made during times when the activities described in 30 TAC § 111.111(a)(1)(E) are not taking place. Visible emissions shall be determined with each stationary vent in clear view of the observer. The observer shall be at least 15 feet, but not more than 0.25 mile, away from each stationary vent during the observation. For outdoor locations, the observer shall select a position where the sun is not directly in the observer's eyes. When condensed water vapor is present within the plume, as it emerges from the emissions outlet, observations must be made beyond the point in the plume at which condensed water vapor is no longer visible. When water vapor within the plume condenses and becomes visible at a distance from the emissions outlet, the observation shall be evaluated at the outlet prior to condensation of water vapor. A certified opacity reader is not required for visible emissions observations.

(5) Compliance Certification:

(a) If visible emissions are not present during the observation, the RO may certify that the source is in compliance with the applicable opacity requirement in 30 TAC § 111.111(a)(1) and (a)(1)(B).

(b) However, if visible emissions are present during the observation, the permit holder shall either list this occurrence as a deviation on the next deviation report as required under 30 TAC § 122.145(2) or conduct the appropriate opacity test specified in 30 TAC § 111.111(a)(1)(F) to determine if the source is in compliance with the opacity requirements. If an opacity test is performed and the source is determined to be in compliance, the RO may certify that the source is in compliance with the applicable opacity requirement. However, if an opacity test is performed and the source is determined to be out of compliance, the permit holder shall list this occurrence as a deviation on the next deviation report as required under 30 TAC § 122.145(2). The opacity test must be performed by a certified opacity reader.

(c) Some vents may be subject to multiple visible emission or monitoring requirements. All credible data must be considered when certifying compliance with this requirement even if the observation or monitoring was

performed to demonstrate compliance with a different requirement.

B. Certification of opacity readers determining opacities under Method 9 (as outlined in 40 CFR Part 60, Appendix A) to comply with opacity monitoring requirements shall be accomplished by completing the Visible Emissions Evaluators Course, or approved agency equivalent, no more than 180 days before the opacity reading.

C. For emission units with contributions from uncombined water, the permit holder shall comply with the requirements of 30 TAC § 111.111(b).

D. Emission limits on nonagricultural processes, except for the steam generators specified in 30 TAC § 111.153, shall comply with the following requirements:

(i) Emissions of PM from any source may not exceed the allowable rates as required in 30 TAC § 111.151(a) (relating to Allowable Emissions Limits)

(ii) Sources with an effective stack height (h_e) less than the standard effective stack height (H_e), must reduce the allowable emission level by multiplying it by $[h_e/H_e]^2$ as required in 30 TAC § 111.151(b)

(iii) Effective stack height shall be calculated by the equation specified in 30 TAC § 111.151(c)

E. Permit holder shall comply with the following requirements for steam generators:

(i) Emissions from any oil or gas fuel-fired steam generator with a heat input capacity greater than 2,500 MMBtu per hour may not exceed 0.1 pound of TSP per MMBtu of heat input, averaged over a two-hour period, as required in 30 TAC § 111.153(c) (relating to Emissions Limits for Steam Generators).

F. Outdoor burning, as stated in 30 TAC § 111.201, shall not be authorized unless the following requirements are satisfied:

(i) Title 30 TAC § 111.205 (relating to Exception for Fire Training)

(ii) Title 30 TAC § 111.221 (relating to Responsibility for Consequences of Outdoor Burning)

4. The permit holder shall comply with the following requirements for units subject to any subpart of 40 CFR Part 60, unless otherwise stated in the applicable subpart:

A. Title 40 CFR § 60.7 (relating to Notification and Recordkeeping)

B. Title 40 CFR § 60.8 (relating to Performance Tests)

C. Title 40 CFR § 60.11 (relating to Compliance with Standards and Maintenance Requirements)

D. Title 40 CFR § 60.12 (relating to Circumvention)

E. Title 40 CFR § 60.13 (relating to Monitoring Requirements)

F. Title 40 CFR § 60.14 (relating to Modification)

G. Title 40 CFR § 60.15 (relating to Reconstruction)

H. Title 40 CFR § 60.19 (relating to General Notification and Reporting Requirements)

5. The permit holder shall comply with the requirements of 30 TAC Chapter 113, Subchapter C, § 113.100 for units subject to any subpart of 40 CFR Part 63, unless otherwise stated in the applicable subpart.

Additional Monitoring Requirements

6. Unless otherwise specified, the permit holder shall comply with the compliance assurance monitoring requirements as specified in the attached "CAM Summary" upon issuance of the permit. In addition, the permit holder shall comply with the following:

A. The permit holder shall comply with the terms and conditions contained in 30 TAC § 122.147 (General Terms and Conditions for Compliance Assurance Monitoring).

B. The permit holder shall report, consistent with the averaging time identified in the "CAM Summary," deviations as defined by the deviation limit in the "CAM Summary." Any monitoring data below a minimum limit or above a maximum limit, that is collected in accordance with the requirements specified in 40 CFR § 64.7(c), shall be reported as a deviation. Deviations shall be reported according to 30 TAC § 122.145 (Reporting Terms and Conditions).

C. The permit holder may elect to collect monitoring data on a more frequent basis and average the data, consistent with the averaging time specified in the "CAM Summary," for purposes of determining whether a deviation has occurred. However, the additional data points must be collected on a regular basis. In no event shall data be collected and used in particular instances in order to avoid reporting deviations. All monitoring data shall be collected in accordance with the requirements specified in 40 CFR § 64.7(c).

D. The permit holder shall operate the monitoring, identified in the attached "CAM Summary," in accordance with the provisions of 40 CFR § 64.7.

E. The permit holder shall comply with the requirements of 40 CFR § 70.6(a)(3)(ii)(A) and 30 TAC § 122.144(1)(A)-(F) for documentation of all required inspections.

7. The permit holder shall comply with the periodic monitoring requirements as specified in the attached "Periodic Monitoring Summary" upon issuance of the permit. Except for, as applicable, monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), the permit holder shall conduct all monitoring in continuous operation (or shall collect data at all required intervals) at all times that the pollutant-specific emissions unit is operating. The permit holder may elect to collect monitoring data on a more frequent basis and average the data, consistent with the averaging time specified in the "Periodic Monitoring Summary," for purposes of determining whether a deviation has occurred. However, the additional data points must be collected on a regular basis. In no event shall data be collected and used in particular instances to avoid reporting deviations. Deviations shall be reported according to 30 TAC § 122.145 (Reporting Terms and Conditions).

New Source Review Authorization Requirements

8. Permit holder shall comply with the requirements of New Source Review authorizations issued or claimed by the permit holder for the permitted area, including permits, permits by rule, standard permits, flexible permits, special permits, permits for existing facilities including Voluntary Emissions Reduction Permits and Electric Generating Facility Permits issued under 30 TAC Chapter 116, Subchapter I, or special exemptions referenced in the New Source Review Authorization References attachment. These requirements:

   A. Are incorporated by reference into this permit as applicable requirements

   B. Shall be located with this operating permit

   C. Are not eligible for a permit shield

9. The permit holder shall comply with the general requirements of 30 TAC Chapter 106, Subchapter A or the general requirements, if any, in effect at the time of the claim of any PBR.

10. The permit holder shall maintain records to demonstrate compliance with any emission limitation or standard that is specified in a permit by rule (PBR) or Standard Permit listed in the New Source Review Authorizations attachment. The records shall yield reliable data from the relevant time period that are representative of the emission unit's compliance with the PBR or Standard Permit. These records may include, but are not limited to, production capacity and throughput, hours of operation, material safety data sheets (MSDS), chemical composition of raw materials, speciation of air contaminant data, engineering calculations, maintenance records, fugitive data, performance tests,

capture/control device efficiencies, direct pollutant monitoring (CEMS, COMS, or PEMS), or control device parametric monitoring. These records shall be made readily accessible and available as required by 30 TAC § 122.144.

A. If applicable, monitoring of control device performance or general work practice standards shall be made in accordance with the TCEQ Periodic Monitoring Guidance document.

B. Any monitoring or recordkeeping data indicating noncompliance with the PBR or Standard Permit shall be considered and reported as a deviation according to 30 TAC § 122.145 (Reporting Terms and Conditions).

Compliance Requirements

11. The permit holder shall certify compliance in accordance with 30 TAC § 122.146. The permit holder shall comply with 30 TAC § 122.146 using at a minimum, but not limited to, the continuous or intermittent compliance method data from monitoring, recordkeeping, reporting, or testing required by the permit and any other credible evidence or information. The certification period may not exceed 12 months and the certification must be submitted within 30 days after the end of the period being certified.

12. Permit holder shall comply with the following 30 TAC Chapter 117 requirements:

    A. The permit holder shall comply with the compliance schedules and submit written notification to the Executive Director as required in 30 TAC Chapter 117, Subchapter H, Division 1:

        (i) For electric utilities in the Dallas-Fort Worth Eight-Hour Nonattainment area, 30 TAC § 117.9130

    B. The permit holder shall comply with the compliance schedules and submit written notification to the TCEQ Executive Director as required in 30 TAC Chapter 117, Subchapter H, Division 1:

        (i) For sources in the Dallas-Fort Worth Eight-Hour Nonattainment area, 30 TAC § 117.9030

    C. The permit holder shall comply with the Initial Control Plan unit identification requirements in 30 TAC § 117.450(a) and (a)(1).

    D. The permit holder shall comply with the requirements of 30 TAC § 117.454 for Final Control Plan Procedures for Attainment Demonstration Emission Specifications and 30 TAC § 117.456 for Revision of Final Control Plan.

13. Use of Emission Credits to comply with applicable requirements:

A. Unless otherwise prohibited, the permit holder may use emission credits to comply with the following applicable requirements listed elsewhere in this permit:

(i) Title 30 TAC Chapter 115

(ii) Title 30 TAC Chapter 117

(iii) Offsets for Title 30 TAC Chapter 116

B. The permit holder shall comply with the following requirements in order to use the emission credits to comply with the applicable requirements:

(i) The permit holder must notify the TCEQ according to 30 TAC § 101.306(c)(2)

(ii) The emission credits to be used must meet all the geographic, timeliness, applicable pollutant type, and availability requirements listed in 30 TAC Chapter 101, Subchapter H, Division 1

(iii) The executive director has approved the use of the credit according to 30 TAC § 101.306(c)(2)

(iv) The permit holder keeps records of the use of credits towards compliance with the applicable requirements in accordance with 30 TAC § 101.302(g) and 30 TAC Chapter 122

14. Use of Discrete Emission Credits to comply with the applicable requirements:

A. Unless otherwise prohibited, the permit holder may use discrete emission credits to comply with the following applicable requirements listed elsewhere in this permit:

(i) Title 30 TAC Chapter 115

(ii) Title 30 TAC Chapter 117

(iii) If applicable, offsets for Title 30 TAC Chapter 116

(iv) Temporarily exceed state NSR permit allowables

B. The permit holder shall comply with the following requirements in order to use the credit to comply with the applicable requirements:

(i) The permit holder must notify the TCEQ according to 30 TAC § 101.376(d)

(ii) The discrete emission credits to be used must meet all the geographic, timeliness, applicable pollutant type, and availability requirements listed in 30 TAC Chapter 101, Subchapter H, Division 4

(iii) The executive director has approved the use of the discrete emission credits according to 30 TAC § 101.376(d)(1)(A)

(iv) The permit holder keeps records of the use of credits towards compliance with the applicable requirements in accordance with 30 TAC § 101.372(h) and 30 TAC Chapter 122

Risk Management Plan

15. For processes subject to 40 CFR Part 68 and specified in 40 CFR § 68.10, the permit holder shall comply with the requirements of the Accidental Release Prevention Provisions in 40 CFR Part 68. The permit holder shall submit to the appropriate agency either a compliance schedule for meeting the requirements of 40 CFR Part 68 by the date provided in 40 CFR § 68.10(a), or as part of the compliance certification submitted under this permit, a certification statement that the source is in compliance with all requirements of 40 CFR Part 68, including the registration and submission of a risk management plan.

Protection of Stratospheric Ozone

16. Permit holders at a site subject to Title VI of the FCAA Amendments shall meet the following requirements for protection of stratospheric ozone.

A. Any on site servicing, maintenance, and repair on refrigeration and nonmotor vehicle air-conditioning appliances using ozone-depleting refrigerants or non-exempt substitutes shall be conducted in accordance with 40 CFR Part 82, Subpart F. Permit holders shall ensure that repairs on or refrigerant removal from refrigeration and nonmotor vehicle air-conditioning appliances using ozone-depleting refrigerants are performed only by properly certified technicians using certified equipment. Records shall be maintained as required by 40 CFR Part 82, Subpart F.

B. The permit holder shall comply with 40 CFR Part 82, Subpart A for controlling the production, transformation, destruction, export or import of a controlled (ozone-depleting) substance or product as specified in 40 CFR § 82.1 - § 82.13 and the applicable Part 82 Appendices.

C. The permit holder shall comply with 40 CFR Part 82, Subpart A, § 82.13 related to recordkeeping and reporting requirements for the production and consumption of ozone depleting substances.

Temporary Fuel Shortages (30 TAC § 112.15)

17. The permit holder shall comply with the following 30 TAC Chapter 112 requirements:

    A. Title 30 TAC § 112.15 (relating to Temporary Fuel Shortage Plan Filing Requirements)

    B. Title 30 TAC § 112.16(a), (a)(1), and (a)(2)(B) - (c) (relating to Temporary Fuel Shortage Plan Operating Requirements)

    C. Title 30 TAC § 112.17 (relating to Temporary Fuel Shortage Plan Notification Procedures)

    D. Title 30 TAC § 112.18 (relating to Temporary Fuel Shortage Plan Reporting Requirements)

Permit Location

18. The permit holder shall maintain a copy of this permit and records related to requirements listed in this permit on site.

Permit Shield (30 TAC § 122.148)

19. A permit shield is granted for the emission units, groups, or processes specified in the attached "Permit Shield." Compliance with the conditions of the permit shall be deemed compliance with the specified potentially applicable requirements or specified potentially applicable state-only requirements listed in the attachment "Permit Shield." Permit shield provisions shall not be modified by the executive director until notification is provided to the permit holder. No later than 90 days after notification of a change in a determination made by the executive director, the permit holder shall apply for the appropriate permit revision to reflect the new determination. Provisional terms are not eligible for this permit shield. Any term or condition, under a permit shield, shall not be protected by the permit shield if it is replaced by a provisional term or condition or the basis of the term and condition changes.

Acid Rain Permit Requirements

20. For unit E-GT (identified in the Certificate of Representation as unit EAST), located at the affected source identified by ORIS/Facility code 54817, the designated representative and the owner or operator, as applicable, shall comply with the following Acid Rain Permit requirements.

    A. General Requirements

        (i) Under 30 TAC § 122.12(1) and 40 CFR Part 72, the Acid Rain Permit requirements contained here are a separable portion of the Federal

Operating Permit (FOP) and have an independent public comment process which may be separate from, or combined with the FOP.

(ii) The owner and operator shall comply with the requirements of 40 CFR Part 72 and 40 CFR Part 76. Any noncompliance with the Acid Rain Permit will be considered noncompliance with the FOP and may be subject to enforcement action.

(iii) The owners and operators of the affected source shall operate the source and the unit in compliance with the requirements of this Acid Rain Permit and all other applicable State and federal requirements.

(iv) The owners and operators of the affected source shall comply with the General Terms and Conditions of the FOP that incorporates this Acid Rain Permit.

(v) The term for the Acid Rain permit shall commence with the issuance of the FOP that incorporates the Acid Rain permit and shall be run concurrent with the remainder of the term of the FOP. Renewal of the Acid Rain permit shall coincide with the renewal of the FOP that incorporates the Acid Rain permit and subsequent terms shall be no more than five years from the date of renewal of the FOP and run concurrent with the permit term of the FOP.

B. Monitoring Requirements

(i) The owners and operators, and the designated representative, of the affected source and each affected unit at the source shall comply with the monitoring requirements contained 40 CFR Part 75.

(ii) The emissions measurements recorded and reported in accordance with 40 CFR Part 75 and any other credible evidence shall be used to determine compliance by the affected source with the acid rain emissions limitations and emissions reduction requirements for SO_2 and NO_x under the ARP.

(iii) The requirements of 40 CFR Part 75 shall not affect the responsibility of the owners and operators to monitor emission of other pollutants or other emissions characteristics at the unit under other applicable requirements of the FCAA Amendments (42 U.S.C. 7401, as amended November 15, 1990) and other terms and conditions of the operating permit for the source.

C. SO_2 emissions requirements

(i) The owners and operators of each source and each affected unit at the source shall comply with the applicable acid rain emissions limitations for SO_2.

(ii) As of the allowance transfer deadline the owners and operators of the affected source and each affected unit at the source shall hold, in the unit's compliance subaccount, allowances in an amount not less than the total annual emissions of SO_2 for the previous calendar year.

(iii) Each ton of SO_2 emitted in excess of the acid rain emissions limitations for SO_2 shall constitute a separate violation of the FCAA amendments.

(iv) An affected unit shall be subject to the requirements under (i) and (ii) of the SO_2 emissions requirements as follows:

(1) Starting January 1, 2000, an affected unit under 40 CFR § 72.6(a)(2); or

(2) Starting on the later of January 1, 2000 or the deadline for monitor certification under 40 CFR Part 75, an affected unit under 40 CFR § 72.6(a)(3).

(v) Allowances shall be held in, deducted from, or transferred into or among Allowance Tracking System accounts in accordance with the requirements of the ARP.

(vi) An allowance shall not be deducted, for compliance with the requirements of this permit, in a calendar year before the year for which the allowance was allocated.

(vii) An allowance allocated by the EPA Administrator or under the ARP is a limited authorization to emit SO_2 in accordance with the ARP. No provision of the ARP, Acid Rain permit application, this Acid Rain Permit, or an exemption under 40 CFR §§ 72.7 or 72.8 and no provision of law shall be construed to limit the authority of the United States to terminate or limit such authorization.

(viii) An allowance allocated by the EPA Administrator under the ARP does not constitute a property right.

D. NO_x Emission Requirements

(i) The owners and operators of the source and each affected unit at the source shall comply with the applicable acid rain emissions limitations for NO_x under 40 CFR Part 76.

E. Excess emissions requirements for SO_2 and NO_x.

(i) The designated representative of an affected unit that has excess emissions in any calendar year shall submit a proposed offset plan, as required under 40 CFR Part 77.

(ii) If an affected source has excess emissions in any calendar year shall, as required by 40 CFR Part 77:

(1) Pay, without demand, the penalty required and pay, upon demand, the interest on that penalty.

(2) Comply with the terms of an approved offset plan.

F. Recordkeeping and Reporting Requirements

(i) Unless otherwise provided, the owners and operators of the affected source and each affected unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time before the end of 5 years, in writing by the permitting authority or the EPA Administrator.

(1) The certificate of representation for the designated representative for the source and each affected unit and all documents that demonstrate the truth of the statements in the certificate of representation, in accordance with 40 CFR § 72.24; provided that the certificate and documents shall be retained on site at the source beyond such 5-year period until such documents are superseded because of the submission of a new certificate of representation changing the designated representative.

(2) All emissions monitoring information, in accordance with 40 CFR Part 75, provided that to the extent that 40 CFR Part 75 provides for a 3-year period for recordkeeping (rather than a five-year period cited in 30 TAC § 122.144), the 3-year period shall apply.

(3) Copies of all reports, compliance certifications, and other submissions and all records made or required under the ARP or relied upon for compliance certification.

(4) Copies of all documents used to complete a acid rain permit application and any other submission under the ARP or to demonstrate compliance with the requirements of the ARP.

(ii) The designated representative of an affected source and each affected unit at the source shall submit the reports required under the ARP including those under 40 CFR Part 72, Subpart I and 40 CFR Part 75.

G. Liability

(i) Any person who knowingly violates any requirement or prohibition of the ARP, a complete acid rain permit application, an acid rain permit, or a

written exemption under 40 CFR §§ 72.7 or 72.8, including any requirement for the payment of any penalty owed to the United States, shall be subject to enforcement pursuant to FCAA § 113(c).

(ii) Any person who knowingly makes a false, material statement in any record, submission, or report under the ARP shall be subject to criminal enforcement pursuant to FCAA § 113(c) and 18 U.S.C. 1001.

(iii) No permit revision shall excuse any violation of the requirements of the ARP that occurs prior to the date that the revision takes effect.

(iv) The affected source and each affected unit shall meet the requirements of the ARP contained in 40 CFR Parts 72 through 78.

(v) Any provision of the ARP that applies to an affected source or the designated representative of an affected source shall also apply to the owners and operators of such source and of the affected units at the source.

(vi) Any provision of the ARP that applies to an affected unit (including a provision applicable to the DR of an affected unit) shall also apply to the owners and operators of such unit. Except as provided under 40 CFR § 72.44 (Phase II repowering extension plans) and 40 CFR § 76.11 (NO_x averaging plans), and except with regard to the requirements applicable to units with a common stack under 40 CFR Part 75 (including 40 CFR §§ 75.16, 75.17, and 75.18), the owners and operators and the DR of one affected unit shall not be liable for any violation by any other affected unit of which they are not owners or operators or the DR and that is located at a source of which they are not owners or operators or the DR.

(vii) Each violation of a provision of 40 CFR Parts 72, 73, 74, 75, 76, 77, and 78 by an affected source or affected unit, or by an owner or operator or DR of such source or unit, shall be a separate violation of the FCAA Amendments.

H. Effect on other authorities. No provision of the ARP, an acid rain permit application, an acid rain permit, or an exemption under 40 CFR §§ 72.7 or 72.8 shall be construed as:

(i) Except as expressly provided in Title IV of the FCAA Amendments, exempting or excluding the owners and operators and, to the extent applicable, the DR of an affected source or affected unit from compliance with any other provision of the FCAA Amendments, including the provisions of Title I of the FCAA Amendments relating to applicable National Ambient Air Quality Standards or State Implementation Plans.

(ii) Limiting the number of allowances a unit can hold; provided, that the number of allowances held by the unit shall not affect the source's obligation to comply with any other provisions of the FCAA Amendments.

(iii) Requiring a change of any kind in any state law regulating electric utility rates and charges, affecting any state law regarding such state regulation, or limiting such state regulation, including any prudence review requirements under such state law.

(iv) Modifying the Federal Power Act or affecting the authority of the Federal Energy Regulatory Commission under the Federal Power Act; or,

(v) Interfering with or impairing any program for competitive bidding for power supply in a state in which such program is established.

I. The number of SO_2 allowances allocated by the EPA in 40 CFR Part 73 is enforceable only by the EPA Administrator.

Clean Air Interstate Rule Permit Requirements

21. For unit E-GT (identified in the Certificate of Representation as unit EAST), located at the site identified by ORIS/Facility code 54817, the designated representative and the owner or operator, as applicable, shall comply with the following Clean Air Interstate Rule (CAIR) Permit requirements. Until approval of the Texas CAIR SIP by EPA, the permit holder shall comply with the equivalent requirements of 40 CFR Part 97 in place of the referenced 40 CFR Part 96 requirements in the Texas CAIR permit and 30 TAC Chapter 122 requirements.

A. General Requirements

(i) Under 30 TAC § 122.420(b) and 40 CFR §§ 96.120(b) and 96.220(b) the CAIR Permit requirements contained here are a separable portion of the Federal Operating Permit (FOP).

(ii) The owners and operators of the CAIR NO_x and the CAIR SO_2 source shall operate the source and the unit in compliance with the requirements of this CAIR permit and all other applicable State and federal requirements.

(iii) The owners and operators of the CAIR NO_x and the CAIR SO_2 source shall comply with the General Terms and Conditions of the FOP that incorporates this CAIR Permit.

(iv) The term for the initial CAIR permit shall commence with the issuance of the revision containing the CAIR permit and shall be the remaining term for the FOP that incorporates the CAIR permit. Renewal of the initial CAIR permit shall coincide with the renewal of the FOP that incorporates

the CAIR permit and subsequent terms shall be no more than five years from the date of renewal of the FOP and run concurrent with the permit term of the FOP.

B. Monitoring and Reporting Requirements

(i) The owners and operators, and the CAIR designated representative, of the CAIR NO_x source and each CAIR NO_x unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements contained 40 CFR Part 96, Subpart HH.

(ii) The owners and operators, and the CAIR designated representative, of the CAIR SO_2 source and each CAIR SO_2 unit at the source shall comply with the monitoring, reporting, and recordkeeping requirements contained 40 CFR Part 96, Subpart HHH.

(iii) The emissions measurements recorded and reported in accordance with 40 CFR Part 96, Subpart HH and any other credible evidence shall be used to determine compliance by the CAIR NO_x source with the CAIR NO_x emissions limitation.

(iv) The emissions measurements recorded and reported in accordance with 40 CFR Part 96, Subpart HHH and any other credible evidence shall be used to determine compliance by the CAIR SO_2 source with the CAIR SO_2 emissions limitation.

C. NO_x emissions requirements

(i) As of the allowance transfer deadline for a control period, the owners and operators of the CAIR NO_x source and each CAIR NO_x unit at the source shall hold, in the source's compliance account, CAIR NO_x allowances available for compliance deductions for the control period under 40 CFR § 96.154(a) in an amount not less than the tons of total nitrogen oxides emissions for the control period from all CAIR NO_x units at the source, as determined in accordance the requirements 40 CFR Part 96, Subpart HH.

(ii) A CAIR NO_x unit shall be subject to the requirements of paragraph C.(i) of this CAIR Permit starting on the later of January 1, 2009, or the deadline for meeting the unit's monitor certification requirements under 40 CFR § 96.170(b)(1), (2), or (5).

(iii) A CAIR NO_x allowance shall not be deducted, for compliance with the requirements of this permit, for a control period in a calendar year before the year for which the CAIR NO_x allowance was allocated.

(iv) CAIR NO_x allowances shall be held in, deducted from or transferred into or among CAIR NO_x Allowance Tracking System accounts in accordance with the requirements of 40 CFR Part 96, Subpart FF or Subpart GG.

(v) A CAIR NO_x allowance is a limited authorization to emit one ton of nitrogen oxides in accordance with the CAIR NO_x Annual Trading Program. No provision of the CAIR NO_x Annual Trading Program, the CAIR permit application, the CAIR permit, or an exemption under 40 CFR § 96.105 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(vi) A CAIR NO_x allowance does not constitute a property right.

(vii) Upon recordation by the Administrator under 40 CFR Part 96, Subpart FF or Subpart GG, every allocation, transfer, or deduction of a CAIR NO_x allowance to or from a CAIR NO_x unit's compliance account is incorporated automatically in this CAIR permit.

D. NO_x excess emissions requirement

(i) If a CAIR NO_x source emits nitrogen oxides during any control period in excess of the CAIR NO_x emissions limitation, the owners and operators of the source and each CAIR NO_x unit at the source shall surrender the CAIR NO_x allowances required for deduction under 40 CFR § 96.154(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law.

(ii) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 96, Subpart AA, the Clean Air Act, and applicable State law.

E. SO_2 emissions requirements

(i) As of the allowance transfer deadline for a control period, the owners and operators of the CAIR SO_2 source and each CAIR SO_2 unit at the source shall hold, in the source's compliance account, CAIR SO_2 allowances available for compliance deductions for the control period under 40 CFR § 96.254(a) and (b) in an amount not less than the tons of total sulfur dioxides emissions for the control period from all CAIR SO_2 units at the source, as determined in accordance the requirements 40 CFR Part 96, Subpart HHH.

(ii) A CAIR SO_2 unit shall be subject to the requirements of paragraph E.(i) of this CAIR Permit starting on the later of January 1, 2010, or the deadline

for meeting the unit's monitor certification requirements under 40 CFR § 96.270(b)(1), (2), or (5).

(iii) A CAIR SO_2 allowance shall not be deducted, for compliance with the requirements of this permit, for a control period in a calendar year before the year for which the CAIR SO_2 allowance was allocated.

(iv) CAIR SO_2 allowances shall be held in, deducted from, or transferred into or among CAIR SO_2 Allowance Tracking System accounts in accordance with the requirements of 40 CFR Part 96, Subpart FFF or Subpart GGG.

(v) A CAIR SO_2 allowance is a limited authorization to emit sulfur dioxide in accordance with the CAIR SO_2 Trading Program. No provision of the CAIR SO_2 Trading Program, the CAIR permit application, the CAIR permit, or an exemption under 40 CFR § 96.205 and no provision of law shall be construed to limit the authority of the State or the United States to terminate or limit such authorization.

(vi) A CAIR SO_2 allowance does not constitute a property right.

(vii) Upon recordation by the Administrator under 40 CFR Part 96, Subpart FFF or Subpart GGG, every allocation, transfer, or deduction of a CAIR SO_2 allowance to or from a CAIR SO_2 unit's compliance account is incorporated automatically in this CAIR permit.

F. SO_2 excess emissions requirements

(i) If a CAIR SO_2 source emits sulfur dioxides during any control period in excess of the CAIR SO_2 emissions limitation, the owners and operators of the source and each CAIR SO_2 unit at the source shall surrender the CAIR SO_2 allowances required for deduction under 40 CFR § 96.254(d)(1) and pay any fine, penalty, or assessment or comply with any other remedy imposed, for the same violations, under the Clean Air Act or applicable State law.

(ii) Each ton of such excess emissions and each day of such control period shall constitute a separate violation of 40 CFR Part 96, Subpart AAA, the Clean Air Act, and applicable State law.

G. Recordkeeping and Reporting Requirements

(i) Unless otherwise provided, the owners and operators of the CAIR NO_x source and each CAIR NO_x unit at the source and the CAIR SO_2 source and each CAIR SO_2 unit at the source shall keep on site at the source each of the following documents for a period of 5 years from the date the document is created. This period may be extended for cause, at any time

before the end of 5 years, in writing by the permitting authority or the Administrator.

(1) The certificate of representation under 40 CFR §§ 96.113 and 96.213 for the CAIR NO_x designated representative for the source and each CAIR NO_x unit and the CAIR SO_2 designated representative for the source and each CAIR SO_2 unit at the source and all documents that demonstrate the truth of the statements in the certificate of representation; provided that the certificate and documents shall be retained on site at the source beyond such 5 year period until such documents are superseded because of the submission of a new certificate of representation under 40 CFR §§ 96.113 and 96.213 changing the CAIR designated representative.

(2) All emissions monitoring information, in accordance with 40 CFR Part 96, Subpart HH and Subpart HHH, provided that to the extent that these subparts provide for a 3-year period for recordkeeping, the 3-year period shall apply.

(3) Copies of all reports, compliance certifications, and other submissions and all records made or required under the CAIR NO_x Annual Trading Program and CAIR SO_2 Trading Program or relied upon for compliance determinations.

(4) Copies of all documents used to complete a CAIR permit application and any other submission under the CAIR NO_x Annual Trading Program and CAIR SO_2 Trading Program or to demonstrate compliance with the requirements of the CAIR NO_x Annual Trading Program and CAIR SO_2 Trading Program.

(ii) The CAIR designated representative of a CAIR NO_x source and each CAIR NO_x unit at the source and a CAIR SO_2 source and each CAIR SO_2 unit at the source shall submit the reports required under the CAIR NO_x Annual Trading Program and the CAIR SO_2 Trading Program including those under 40 CFR Part 96, Subpart HH and Subpart HHH.

H. The CAIR NO_x source and each CAIR NO_x unit shall meet the requirements of the CAIR NO_x Annual Trading Program contained in 40 CFR Part 96, Subparts AA through II.

I. The CAIR SO_2 source and each CAIR SO_2 unit shall meet the requirements of the CAIR SO_2 Trading Program contained in 40 CFR Part 96, Subparts AAA through III.

J. Any provision of the CAIR NO_x Annual Trading Program and the CAIR SO_2 Trading Program that applies to a CAIR NO_x source or CAIR SO_2 source or the CAIR designated representative of a CAIR NO_x source or CAIR SO_2 source shall also apply to the owners and operators of such source and the units at the source.

K. Any provision of the CAIR NO_x Annual Trading Program and the CAIR SO_2 Trading Program that applies to a CAIR NO_x unit or CAIR SO_2 unit or the CAIR designated representative of a CAIR NO_x unit or CAIR SO_2 unit shall also apply to the owners and operators of such unit.

L. No provision of the CAIR NO_x Annual Trading Program, CAIR SO_2 Trading Program, a CAIR permit application, a CAIR permit, or an exemption under 40 CFR §§ 96.105 or 96.205 shall be construed as exempting or excluding the owners and operators, and the CAIR designated representative, of a CAIR NO_x source or CAIR NO_x unit or a CAIR SO_2 source or CAIR SO_2 unit from compliance with any other provision of the applicable, approved State implementation plan, a federally enforceable permit, or the Clean Air Act.

Attachments

Applicable Requirements Summary

Additional Monitoring Requirements

Permit Shield

New Source Review Authorization References

Applicable Requirements Summary

Unit Summary 24

Applicable Requirements Summary 25

Note: A "none" entry may be noted for some emission sources in this permit's "Applicable Requirements Summary" under the heading of "Monitoring and Testing Requirements" and/or "Recordkeeping Requirements" and/or "Reporting Requirements." Such a notation indicates that there are no requirements for the indicated emission source as identified under the respective column heading(s) for the stated portion of the regulation when the emission source is operating under the conditions of the specified SOP Index Number. However, other relevant requirements pursuant to 30 TAC Chapter 122 including Recordkeeping Terms and Conditions (30 TAC § 122.144), Reporting Terms and Conditions (30 TAC § 122.145), and Compliance Certification Terms and Conditions (30 TAC § 122.146) continue to apply.

Unit Summary

Unit/Group/ Process ID No.	Unit Type	Group/Inclusive Units	SOP Index No.	Regulation	Requirement Driver
E-HRSG	BOILERS/STEAM GENERATORS/STEAM GENERATING UNITS	N/A	NG1	40 CFR Part 60, Subpart Da	No changing attributes.
FO-LOAD1	LOADING/UNLOADING OPERATIONS	N/A	FO-115	30 TAC Chapter 115, Loading and Unloading of VOC	No changing attributes.
FP-1	SRIC ENGINES	N/A	63ZZZZ	40 CFR Part 63, Subpart ZZZZ	No changing attributes
E-GT	STATIONARY TURBINES	N/A	FO1	40 CFR Part 60, Subpart GG	FUEL SUPPLY = Stationary gas turbine is supplied its fuel from a bulk storage tank, FUEL TYPE FIRED = Liquid fuel
E-GT	STATIONARY TURBINES	N/A	NG2	40 CFR Part 60, Subpart GG	FUEL SUPPLY = Stationary gas turbine is supplied its fuel without intermediate bulk storage tank, FUEL TYPE FIRED = Natural gas meeting the definition in § 60.331(u).
OIL-TK	STORAGE TANKS/VESSELS	N/A	115-FOT	30 TAC Chapter 115, Storage of VOCs	No changing attributes.

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
E-HRSG	EU	NG1	PM(OPACITY)	40 CFR Part 60, Subpart Da	§ 60.42Da(b) § 60.48Da(c)	No owner or operator shall discharge any gases which exhibit greater than 20 percent opacity (6-minute average), except for one 6-minute period per hour of not more than 27 percent opacity. Owners and operators that elect to install, calibrate, maintain and operate a CEMS for measuring PM emissions are exempt from the opacity standard.	§ 60.48Da(q) § 60.49Da(a)(3) § 60.50Da(a) § 60.50Da(b)(3) [G]§ 60.50Da(o)	[G]§ 60.52Da(b)	[G]§ 60.51Da(h) § 60.51Da(j)
E-HRSG	EU	NG1	PM	40 CFR Part 60, Subpart Da	§ 60.42Da(a)(1) § 60.48Da(c)	No owner or operator discharge any gases that contain PM in excess of 13 ng/J (0.03 lb/MMBtu) heat input derived from the combustion of solid, liquid, or gaseous fuel.	§ 60.50Da(a) § 60.50Da(b)(1) [G]§ 60.50Da(b)(2) [G]§ 60.50Da(e) § 60.50Da(f) ** See Periodic Monitoring Summary	None	§ 60.51Da(a) [G]§ 60.51Da(h) § 60.51Da(j)
E-HRSG	EU	NG1	NO_x	40 CFR Part 60, Subpart Da	[G]§ 60.44Da(a) § 60.48Da(c)	No owner or operator shall discharge any gases that contain NOx (expressed as NO2) in excess of the specified emission limits in §60.44Da(a)(1) and (a)(2), based on a 30-day rolling average basis. §60.44Da(a)(1)-(2)	§ 60.48Da(e) § 60.48Da(f) § 60.48Da(g)(1) § 60.48Da(h) § 60.48Da(j)(2) § 60.49Da(c)(2) § 60.49Da(d) § 60.49Da(e) § 60.49Da(f)(1) § 60.49Da(h) § 60.49Da(h)(2) § 60.49Da(h)(3) § 60.49Da(h)(4) § 60.49Da(i)(3)(ii) § 60.49Da(i)(4) § 60.49Da(j)(2) § 60.49Da(j)(3) § 60.49Da(j)(4) [G]§ 60.49Da(s)	[G]§ 60.49Da(s) [G]§ 60.49Da(w)	[G]§ 60.49Da(s) [G]§ 60.49Da(w) § 60.51Da(a) § 60.51Da(b) § 60.51Da(b)(1) § 60.51Da(b)(2) § 60.51Da(b)(4) § 60.51Da(b)(5) § 60.51Da(b)(6) § 60.51Da(b)(7) § 60.51Da(b)(8) § 60.51Da(b)(9) [G]§ 60.51Da(c) § 60.51Da(f) [G]§ 60.51Da(h) § 60.51Da(j) § 60.51Da(k)

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B.)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
							[G]§ 60.49Da(w) § 60.50Da(a) [G]§ 60.50Da(d) [G]§ 60.50Da(e) § 60.50Da(f)		
B-HRSG	EU	NG1	SO_2	40 CFR Part 60, Subpart Da	§ 60.43Da(b)(2) § 60.43Da(g) § 60.48Da(c)	No owner or operator shall discharge any gases that contain sulfur dioxide in excess of 100 percent of the potential combustion concentration (zero percent reduction) when emissions are less than 86 ng/J (0.20 lb/MMBtu) heat input.	§ 60.48Da(e) § 60.48Da(f) § 60.48Da(g)(1) § 60.48Da(h) § 60.49Da(j)(1) § 60.49Da(j)(3) § 60.49Da(j)(4) § 60.50Da(a) [G]§ 60.50Da(c) [G]§ 60.50Da(e) § 60.50Da(f) ** See Periodic Monitoring Summary	None	§ 60.51Da(a) § 60.51Da(b) § 60.51Da(b)(1) § 60.51Da(b)(2) § 60.51Da(b)(4) § 60.51Da(b)(5) § 60.51Da(b)(6) § 60.51Da(b)(7) [G]§ 60.51Da(c) [G]§ 60.51Da(d) [G]§ 60.51Da(e) § 60.51Da(f) [G]§ 60.51Da(h) § 60.51Da(j) § 60.51Da(k)
FO-LOAD1	EU	FO-115	VOC	30 TAC Chapter 115, Loading and Unloading of VOC	§ 115.217(a)(1) § 115.212(a)(2) [G]§ 115.212(a)(7) § 115.214(a)(1)(B) § 115.214(a)(1)(D) § 115.214(a)(1)(D)(i)	Vapor pressure (at land-based operations). All land-based loading and unloading of VOC with a true vapor pressure less than 0.5 psia is exempt from the requirements of this division, except as specified.	§ 115.214(a)(1)(A) § 115.214(a)(1)(A)(i) § 115.215 § 115.215(4)	§ 115.216 § 115.216(2) § 115.216(3)(B)	None
FP-1	EU	63ZZZZ	HAPS	40 CFR Part 63, Subpart ZZZZ	§ 63.6603(a)-Table 2d.4 § 63.6595(a)(1) § 63.6605(a) § 63.6605(b) § 63.6625(e) § 63.6625(h) § 63.6625(i) § 63.6640(b) § 63.6640(f)(1)	For each existing emergency stationary CI RICE and black start stationary CI RICE, located at an area source, you must comply with the requirements as specified in Table 2d.4.a-c.	§ 63.6625(f) § 63.6625(i) § 63.6640(a) § 63.6640(a)-Table 6.9.a.i § 63.6640(a)-Table 6.9.a.ii § 63.6640(b)	§ 63.6625(i) § 63.6655(a) § 63.6655(a)(1) § 63.6655(a)(2) § 63.6655(a)(4) § 63.6655(a)(5) § 63.6655(d) § 63.6655(e) § 63.6655(f) § 63.6660(a)	§ 63.6640(b) § 63.6640(e) § 63.6645(a)(5) § 63.6650(f) § 63.6665

Applicable Requirements Summary

Unit, Group, Process ID No.	Unit, Group, Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation, Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
								§ 63.6660(b) § 63.6660(c) § 63.6665	
E-GT	EU	FO1	SO2	40 CFR Part 60, Subpart GG	§ 60.333(b)	No stationary gas turbine shall burn any fuel which contains sulfur in excess of 0.8% by weight.	§ 60.334(h) § 60.334(h)(4)	None	None
E-GT	EU	FO1	NOX	40 CFR Part 60, Subpart GG	§ 60.332(a)(1) § 60.332(a)(3) § 60.332(f) § 60.332(i)	No owner or operator shall discharge into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of the amount as determined from the specified equation.	[G]§ 60.334(b) § 60.334(j) § 60.334(j)(1) [G]§ 60.334(j)(1)(iii) [G]§ 60.335(a) § 60.335(b)(2) § 60.335(b)(3)	[G]§ 60.334(b)	§ 60.334(j) § 60.334(j)(3) § 60.334(j)(5)
E-GT	EU	NG2	SO2	40 CFR Part 60, Subpart GG	§ 60.333(b)	No stationary gas turbine shall burn any fuel which contains sulfur in excess of 0.8% by weight.	§ 60.334(h) § 60.334(h)(4)	None	None
E-GT	EU	NG2	NOX	40 CFR Part 60, Subpart GG	§ 60.332(a)(1) § 60.332(a)(3) § 60.332(f) § 60.332(i)	No owner or operator shall discharge into the atmosphere from any stationary gas turbine, any gases which contain nitrogen oxides in excess of the amount as determined from the specified equation.	[G]§ 60.334(b) § 60.334(j) § 60.334(j)(1) [G]§ 60.334(j)(1)(iii) [G]§ 60.335(a) § 60.335(b)(2) § 60.335(b)(3) ** See CAM Summary	[G]§ 60.334(b)	§ 60.334(j) § 60.334(j)(3) § 60.334(j)(5)
OIL-TK	EU	115-FOT	VOC	30 TAC Chapter 115, Storage of VOCs	§ 115.111(a)(1)	Except as provided in §115.118 of this title (relating to Recordkeeping Requirements), any volatile organic compound (VOC) with a true vapor pressure less than 1.5 pounds per square inch absolute (psia) (10.3 kPa) at storage conditions is	None	§ 115.118(a)(1) § 115.118(a)(6)(A)	None

Applicable Requirements Summary

Unit Group Process ID No.	Unit Group Process Type	SOP Index No.	Pollutant	State Rule or Federal Regulation Name	Emission Limitation Standard or Equipment Specification Citation	Textual Description (See Special Term and Condition 1.B)	Monitoring And Testing Requirements	Recordkeeping Requirements (30 TAC § 122.144)	Reporting Requirements (30 TAC § 122.145)
						exempt from the requirements of this division (relating to the Storage of Volatile Organic Compounds).			

Additional Monitoring Requirements

Compliance Assurance Monitoring Summary 30

Periodic Monitoring Summary 31

CAM Summary

Unit/Group/Process Information	
ID No.: E-GT	
Control Device ID No.: SCR	Control Device Type: Selective Catalytic Reduction (SCR)
Control Device ID No.: STINJT	Control Device Type: Other Control Device Type
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart GG	SOP Index No.: NG2
Pollutant: NOX	Main Standard: § 60.332(a)(1)
Monitoring Information	
Indicator: Nitrogen Oxides Concentration	
Minimum Frequency: four times per hour	
Averaging Period: one hour	
Deviation Limit: 110.2 ppmv NOX (corrected to 15% oxygen), when firing natural gas. 106.2 ppmv NOX (corrected to 15% oxygen), when firing fuel oil.	
CAM Text: Use a continuous emission monitoring system (CEMS) to measure and record the concentration of nitrogen oxides and either oxygen or carbon dioxide in the exhaust stream of the control device. The CEMS shall be operated in accordance with the monitoring requirements of 40 CFR § 60.13 and the performance specifications of 40 CFR Part 60, Appendix B. NOx Emissions shall be corrected/calculated in units of the underlying applicable emission limitation (grams per horsepower-hour, pounds per MMBtu, pounds per hour).	

Periodic Monitoring Summary

Unit/Group/Process Information	
ID No.: E-HRSG	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Da	SOP Index No.: NG1
Pollutant: PM	Main Standard: § 60.42Da(a)(1)
Monitoring Information	
Indicator: Fuel type	
Minimum Frequency: Annually or at any time an alternate fuel is used	
Averaging Period: n/a	
Deviation Limit: Firing of alternative fuel or failure to keep records of fuel type.	
Periodic Monitoring Text: Record the type of fuel used. If an alternative fuel is fired either alone or in combination it shall be considered a deviation.	

Periodic Monitoring Summary

Unit/Group/Process Information	
ID No.: E-HRSG	
Control Device ID No.: N/A	Control Device Type: N/A
Applicable Regulatory Requirement	
Name: 40 CFR Part 60, Subpart Da	SOP Index No.: NG1
Pollutant: SO_2	Main Standard: §.60.43Da(b)(2)
Monitoring Information	
Indicator: Fuel sulfur content	
Minimum Frequency: every 30-days	
Averaging Period: 30-days	
Deviation Limit: Maximum SO2 emissions = 0.20 lb/MMBtu heat input	
Periodic Monitoring Text: Use the requirements of 40 CFR Part 75, Appendix D Sections 2.3.1.1 and 2.3.1.4 to satisfy the monitoring provisions of 40 CFR 60.48Da, demonstrating compliance with the SO2 limit.	

Permit Shield

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Permit Shield

The Executive Director of the TCEQ has determined that the permit holder is not required to comply with the specific regulation(s) identified for each emission unit, group, or process in this table.

Unit/Group/Process		Regulation	Basis of Determination
ID No.	Group/Inclusive Units		
E-HRSG	N/A	40 CFR Part 63, Subpart DDDDD	Site is not a major HAP source (Boiler MACT)
FP-1	N/A	40 CFR Part 60, Subpart IIII	Diesel fire pump engine constructed prior to applicability date
E-GT	N/A	40 CFR Part 63, Subpart YYYY	Site is not a major HAP source (Turbine MACT)
OIL-TK	N/A	40 CFR Part 60, Subpart Kb	Fuel oil tank storing material with a TVP less than 3.5 kPa
OIL-TK2	N/A	30 TAC Chapter 115, Storage of VOCs	Storage capacity is less than 1,000 gallons.
OIL-TK2	N/A	40 CFR Part 60, Subpart Kb	Fuel oil tank storing material with a TVP less than 3.5 kPa

New Source Review Authorization References

New Source Review Authorization References 36

New Source Review Authorization References by Emission Unit.....37

New Source Review Authorization References

The New Source Review authorizations listed in the table below are applicable requirements under 30 TAC Chapter 122 and enforceable under this operating permit.

Prevention of Significant Deterioration (PSD) Permits	
PSD Permit No.: PSDTX839	
Title 30 TAC Chapter 116 Permits, Special Permits, and Other Authorizations (Other Than Permits By Rule, PSD Permits, or NA Permits) for the Application Area	
Authorization No.: 25384	
Permits By Rule (30 TAC Chapter 106) for the Application Area	
Number: 106.227	Version No./Date: 09/04/2000
Number: 106.263	Version No./Date: 11/01/2001
Number: 106.371	Version No./Date: 09/04/2000
Number: 106.373	Version No./Date: 09/04/2000
Number: 106.454	Version No./Date: 11/01/2001
Number: 106.472	Version No./Date: 09/04/2000
Number: 106.511	Version No./Date: 09/04/2000

New Source Review Authorization References by Emissions Unit

The following is a list of New Source Review (NSR) authorizations for emission units listed elsewhere in this operating permit. The NSR authorizations are applicable requirements under 30 TAC Chapter 122 and enforceable under this operating permit.

Unit/Group/Process ID No.	Emission Unit Name/Description	New Source Review Authorization
E-GT	250 MW GAS TURBINE	25384, PSDTX839
E-HRSG	375 MMBTU/HR HRSG	25384, PSDTX839
FO-LOAD1	FUEL LOADING UNLOADING POINT	106.472/09/04/2000
FP-1	182-HP DIESEL FIRE WATER PUMP ENGINE	25384, PSDTX839
OIL-TK2	FUEL OIL TANK 2	25384, PSDTX839
OIL-TK	FUEL OIL TANK	25384, PSDTX839

Appendix A

Acronym List 39

Acronym List

The following abbreviations or acronyms may be used in this permit:

ACFM ..... actual cubic feet per minute
AMOC ..... alternate means of control
ARP ..... Acid Rain Program
ASTM ..... American Society of Testing and Materials
B/PA ..... Beaumont/Port Arthur (nonattainment area)
CAM ..... Compliance Assurance Monitoring
CD ..... control device
COMS ..... continuous opacity monitoring system
CVS ..... closed-vent system
D/FW ..... Dallas/Fort Worth (nonattainment area)
DR ..... Designated Representative
EIP ..... El Paso (nonattainment area)
EP ..... emission point
EPA ..... U.S. Environmental Protection Agency
EU ..... emission unit
FCAA Amendments ..... Federal Clean Air Act Amendments
FOP ..... federal operating permit
GF ..... grandfathered
gr/100 scf ..... grains per 100 standard cubic feet
HAP ..... hazardous air pollutant
H/G/B ..... Houston/Galveston/Brazoria (nonattainment area)
H_2S ..... hydrogen sulfide
ID No. ..... identification number
lb/hr ..... pound(s) per hour
MMBtu/hr ..... Million British thermal units per hour
MRRT ..... monitoring, recordkeeping, reporting, and testing
NA ..... nonattainment
N/A ..... not applicable
NADB ..... National Allowance Data Base
NO_x ..... nitrogen oxides
NSPS ..... New Source Performance Standard (40 CFR Part 60)
NSR ..... New Source Review
ORIS ..... Office of Regulatory Information Systems
Pb ..... lead
PBR ..... Permit By Rule
PM ..... particulate matter
ppmv ..... parts per million by volume
PSD ..... prevention of significant deterioration
RO ..... Responsible Official
SO_2 ..... sulfur dioxide
TCEQ ..... Texas Commission on Environmental Quality
TSP ..... total suspended particulate
TVP ..... true vapor pressure
U.S.C. ..... United States Code
VOC ..... volatile organic compound

ATTACHMENT E

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

May 1, 2008

STATE OF TEXAS §
COUNTY OF TRAVIS §

OCT 10 2012

DUFF & PHELPS LLC
GREG MAXIM
919 CONGRESS #1450
AUSTIN, TX 78701

This letter is to inform you that on 5/1/2008, the technical review of Use Determination Application 07-11969 was completed. This application is for:

BRAZOS VALLEY ENERGY LP
BRAZOS VALLEY ENERGY
3440 LOCKWOOD RD
RICHMOND, TX 77469

The use determination is included with this letter. In order to request an exemption, a copy of this Use Determination, along with a completed exemption request form #50-248 (can be found at www.cpa.state.tx.us), must be provided to the Chief Appraiser of the appropriate appraisal district. This request must be made by April 30.

House Bill 3121, enacted during the 77th Legislative Session, established a process for appealing a use determination. The Texas Commission on Environmental Quality (TCEQ) rules that implement the appeals process are at 30 TAC 17.25. Pursuant to 17.25(a)(1), an appeal must be filed within 20 days of receipt of the use determination. Should you choose to appeal the use determination, please submit a copy of your appeal to the TCEQ Tax Relief for Pollution Control Property program at the time of filing the appeal with the Chief Clerk of the commission.

If you have any questions or require any additional information, please contact the Tax Relief for Pollution Control Property Program at (512) 239-3100.

Sincerely,

David Greer
Team Leader, Pollution Prevention

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

USE DETERMINATION

The Texas Commission on Environmental Quality has reviewed Use Determination Application, 07-11969, filed by:

BRAZOS VALLEY ENERGY LP
BRAZOS VALLEY ENERGY
3440 LOCKWOOD RD
RICHMOND TX 77469

The pollution control property/project listed in the Use Determination Application is:

This facility has two thermally efficient heat recovery steam generators (HRSGs) and one steam turbine. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

The outcome of the review is:

A 100% positive use determination for the two Heat Recovery Steam Generators. This equipment is considered to be pollution control equipment and was installed to meet or exceed federal or state regulations.

A negative determination is issued for the steam turbine. The use of the steam turbine does not provide an environmental benefit at the site. The steam turbine is not considered to be pollution control equipment.

Executive Director

May 2 2008
Date

TAX RELIEF FOR POLLUTION CONTROL PROPERTY: TECHNICAL REVIEW DOCUMENT

Reviewed By: RLH App. No.: 07 - 11969 Review Start Date: 4/8/2008

Company Name: BRAZOS VALLEY ENERGY LP
Facility Name: BRAZOS VALLEY ENERGY
County: FORT BEND Outstanding Fees: N
Batch/Voucher Number:B500156

ADMINISTRATIVE REVIEW

Administrative Complete Date:4/8/2008

TIER LEVEL
What Tier is this application? The application was filed as a Tier IV application. Is this the appropriate level?

The property listed on this application, Heat Recovery Steam Generators and a steam turbine are items B8 and B10 on the Equipment and Categories List. This application was filed as a Tier IV. Tier IV is the appropriate level for this application.

RELEVANT RULE, REGULATION, OR STATUTORY PROVISION
The rule listed in the application is: 40 CFR 60.44Da
The appropriate rule is: 40 CFR 60.44Da

Explain why this is the appropriate rule?

40 CFR 60.Subpart DA: Standards of Performance for New Stationary Sources. Standards of performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978. This is an appropriate rule.

BRIEF DESCRIPTION OF PROPERTY
The property is described as:

This facility has two thermally efficient heat recovery steam generators (HRSGs) and one steam turbine. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

Is an adequate description and purpose of the property provided? Does it list the anticipated environmental benefits? Are sketches and flow diagrams provided if needed?

An adequate description of the property was provided, and the purpose of the property was listed. The anticipated environmental benefit is listed. Sketches and flow diagrams were provided.

DECISION FLOWCHART(30 TAC 17.15(a))
Mark the appropriate boxes: Box 3 Box 5 Box 6(IV) Y Box 10(III) Box 12(I) Box 13(II)
PART B DECISION FLOWCHART (17.15(b))
Mark the appropriate boxes: Box 1Y Box 2 Y Box 3 Y

Describe how the property flowed through the Decision Flowchart:

Since the property is listed on Part B of the Equipment & Categories List this property leaves the Decision Flow Chart at Box 6. It passes through Box 1 of the Part B Decision Flow Chart with a yes answer. The use of this property at a combined cycle plant, as opposed to having a simple

cycle plant, provides an environmental benefit of reduced NOx emissions at the site. So there is a Yes answer for Box 2, Since there is a reduction in NOx emissions there is an environmental rule which is being met so there is a yes answer to Box 3. The steam turbine passes through Box 1 on the Part B Decision Flow Chart with a yes answer. Since the use of the steam turbine does not provide an environmental benefit at the site a no answer is the result of Box 2. The steam turbine is not eligible for a positive determination.

TIER III or IV APPLICATIONS

Does your calculation agree with the applicants?

No. The application contains a proposed formula for calculating the pollution control value of the HRSGs and the steam turbine. The formula is outcome determinative, and its focus is not on the pollution control aspect of the property. The Executive Director disagrees with this formula.

PROPERTY CATEGORIES AND COSTS

Is the table completed correctly? Has the applicant certified that all listed property became taxable for the first time after January 1, 1994? Is all information necessary for conducting the technical review included.

The table was completed correctly. The applicant certified that all listed property became taxable for the first time after January 1, 1994. All the information necessary for conducting the technical review was included on the application.

TECHNICAL DEFICIENCIES

Is the application complete as received: Y If the application was not administratively complete explain below when justifying the final decision in the final determination section. If the application was not technically complete then:

Provide the language to be used in the Notice of Deficiency (NOD) letter:

Summarize the NOD response:

Provide the language used in the second NOD letter:

Summarize the second NOD response:

Provide the language used in the thied NOD letter:

Summarize the third NOD response:

FINAL DETERMINATION

If the property description has been summarized enter the detailed property description:

This facility has two thermally efficient heat recovery steam generators (HRSGs) and one steam

turbine. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

Provide the reason for your final determination:

The Heat Recovery Steam Generators meet all of the requirements of Chapter 17. A positive use determination based on the most appropriate formula should be issued for the Heat Recovery Steam Generators. The most appropriate formula has been determined by the Executive Director. A negative determination should be issued for the steam turbine. The use of the steam turbine does not result in there being an environmental benefit at the site.

Provide the language for the final determination.

A positive use determination of 100% for the two Heat Recovery Steam Generators. A negative determination is issued for the steam turbine. The use of the steam turbine does not provide an environmental benefit at the site. The steam turbine is not considered to be pollution control equipment.

Highlight the required signatures and establish the appropriate due dates.

Reviewed: Ronald [illegible] **Date Signed:** 5/1/08

Peer Reviewed: Gary McCrotham **Date Signed:** 5-1-08

Team Leader: [illegible] **Date Signed:** 5/1/08

Section Manager: [illegible] **Date Signed:** MAY 1 2008

Division Director: [illegible] **Date Signed:** MAY 1 2008

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

May 1, 2008

DUFF & PHELPS LLC
GREG MAXIM
919 CONGRESS #1450
AUSTIN, TX 78701

This letter is to inform you that on 5/1/2008, the technical review of Use Determination Application 07-11966 was completed. This application is for:

FREESTONE POWER GENERATION LP
FREESTONE ENERGY CENTER
13.6 MI N ON FM 488
FAIRFIELD, TX 75840

The use determination is included with this letter. In order to request an exemption, a copy of this Use Determination, along with a completed exemption request form #50-248 (can be found at www.cpa.state.tx.us), must be provided to the Chief Appraiser of the appropriate appraisal district. This request must be made by April 30.

House Bill 3121, enacted during the 77th Legislative Session, established a process for appealing a use determination. The Texas Commission on Environmental Quality (TCEQ) rules that implement the appeals process are at 30 TAC 17.25. Pursuant to 17.25(a)(1), an appeal must be filed within 20 days of receipt of the use determination. Should you choose to appeal the use determination, please submit a copy of your appeal to the TCEQ Tax Relief for Pollution Control Property program at the time of filing the appeal with the Chief Clerk of the commission.

If you have any questions or require any additional information, please contact the Tax Relief for Pollution Control Property Program at (512) 239-3100.

Sincerely,

David Greer
Team Leader, Pollution Prevention

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

USE DETERMINATION

The Texas Commission on Environmental Quality has reviewed Use Determination Application, 07-11966, filed by:

FREESTONE POWER GENERATION LP
FREESTONE ENERGY CENTER
13.6 MI N ON FM 488
FAIRFIELD TX 75840

The pollution control property/project listed in the Use Determination Application is:

This facility has four thermally efficient heat recovery steam generators (HRSGs) and two steam turbines. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

The outcome of the review is:

A 100% positive use determination for the four Heat Recovery Steam Generators. This equipment is considered to be pollution control equipment and was installed to meet or exceed federal or state regulations.

A negative determination is issued for the two steam turbines. The use of the steam turbines does not provide an environmental benefit at the site. The steam turbines are not considered to be pollution control equipment.

Executive Director

May 1 2008
Date

TAX RELIEF FOR POLLUTION CONTROL PROPERTY: TECHNICAL REVIEW DOCUMENT

Reviewed By: RLH App. No.: 07 - 11966 Review Start Date: 4/8/2008

Company Name: FREESTONE POWER GENERATION LP
Facility Name: FREESTONE POWER GENERATION LP
County: FREESTONE Outstanding Fees: N
Batch/Voucher Number:B500156

ADMINISTRATIVE REVIEW

Administrative Complete Date:4/8/2008

TIER LEVEL
What Tier is this application? The application was filed as a Tier IV application. Is this the appropriate level?

The property listed on this application, Heat Recovery Steam Generators and a steam turbine are items B8 and B10 on the Equipment and Categories List. This application was filed as a Tier IV. Tier IV is the appropriate level for this application.

RELEVANT RULE, REGULATION, OR STATUTORY PROVISION
The rule listed in the application is: 40 CFR 60.44Da
The appropriate rule is: 40 CFR 60.44Da

Explain why this is the appropriate rule?

40 CFR 60.Subpart DA: Standards of Performance for New Stationary Sources. Standards of performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978. This is an appropriate rule.

BRIEF DESCRIPTION OF PROPERTY
The property is described as:

This facility has four thermally efficient heat recovery steam generators (HRSGs) and two steam turbines. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

Is an adequate description and purpose of the property provided? Does it list the anticipated environmental benefits? Are sketches and flow diagrams provided if needed?

An adequate description of the property was provided, and the purpose of the property was listed. The anticipated environmental benefit is listed. Sketches and flow diagrams were provided.

DECISION FLOWCHART(30 TAC 17.15(a))
Mark the appropriate boxes: Box 3 Box 5 Box 6(IV) Y Box 10(III) Box 12(I) Box 13(II)
PART B DECISION FLOWCHART (17.15(b))
Mark the appropriate boxes: Box 1Y Box 2 Y Box 3 Y

Describe how the property flowed through the Decision Flowchart:

Since the property is listed on Part B of the Equipment & Categories List this property leaves the Decision Flow Chart at Box 6. It passes through Box 1 of the Part B Decision Flow Chart with a yes answer. The use of this property at a combined cycle plant, as opposed to having a simple

cycle plant, provides an environmental benefit of reduced NOx emissions at the site. So there is a Yes answer for Box 2. Since there is a reduction in NOx emissions there is an environmental rule which is being met so there is a yes answer to Box 3. The steam turbine passes through Box 1 on the Part B Decision Flow Chart with a yes answer. Since the use of the steam turbine does not provide an environmental benefit at the site a no answer is the result of Box 2. The steam turbine is not eligible for a positive determination.

TIER III or IV APPLICATIONS

Does your calculation agree with the applicants?

No. The application contains a proposed formula for calculating the pollution control value of the HRSGs and the steam turbine. The formula is outcome determinative, and its focus is not on the pollution control aspect of the property. The Executive Director disagrees with this formula.

PROPERTY CATEGORIES AND COSTS

Is the table completed correctly? Has the applicant certified that all listed property became taxable for the first time after January 1, 1994? Is all information necessary for conducting the technical review included.

The table was completed correctly. The applicant certified that all listed property became taxable for the first time after January 1, 1994. All the information necessary for conducting the technical review was included on the application.

TECHNICAL DEFICIENCIES

Is the application complete as received: Y If the application was not administratively complete explain below when justifying the final decision in the final determination section. If the application was not technically complete then:

Provide the language to be used in the Notice of Deficiency (NOD) letter:

Summarize the NOD response:

Provide the language used in the second NOD letter:

Summarize the second NOD response:

Provide the language used in the thied NOD letter:

Summarize the third NOD response:

FINAL DETERMINATION

If the property description has been summarized enter the detailed property description:

This facility has four thermally efficient heat recovery steam generators (HRSGs) and two steam

turbines. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

Provide the reason for your final determination:

The Heat Recovery Steam Generators meet all of the requirements of Chapter 17. A positive use determination based on the most appropriate formula should be issued for the Heat Recovery Steam Generators. The most appropriate formula has been determined by the Executive Director. A negative determination should be issued for the steam turbine. The use of the steam turbine does not result in there being an environmental benefit at the site.

Provide the language for the final determination:

A positive use determination of 100% for the four Heat Recovery Steam Generators. A negative determination is issued for the steam turbine. The use of the steam turbine does not provide an environmental benefit at the site. The steam turbine is not considered to be pollution control equipment.

Highlight the required signatures and establish the appropriate due dates.

Reviewed: [signature] **Date Signed:** 5/1/08

Peer Reviewed: [signature] **Date Signed:** 5-1-08

Team Leader: [signature] **Date Signed:** 5/1/08

Section Manager: [signature] **Date Signed:** MAY 1 2008

Division Director: [signature] **Date Signed:** MAY 1 2008

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

May 1, 2008

OCT 10 2012

DUFF & PHELPS LLC
GREG MAXIM
919 CONGRESS #1450
AUSTIN, TX 78701

This letter is to inform you that on 5/1/2008, the technical review of Use Determination Application 07-11926 was completed. This application is for:

NAVASOTA WHARTON ENERGY PARTNERS LP
COLORADO BEND
3821 S STATE HWY 60
WHARTON, TX 77488

The use determination is included with this letter. In order to request an exemption, a copy of this Use Determination, along with a completed exemption request form #50-248 (can be found at www.cpa.state.tx.us), must be provided to the Chief Appraiser of the appropriate appraisal district. This request must be made by April 30.

House Bill 3121, enacted during the 77th Legislative Session, established a process for appealing a use determination. The Texas Commission on Environmental Quality (TCEQ) rules that implement the appeals process are at 30 TAC 17.25. Pursuant to 17.25(a)(1), an appeal must be filed within 20 days of receipt of the use determination. Should you choose to appeal the use determination, please submit a copy of your appeal to the TCEQ Tax Relief for Pollution Control Property program at the time of filing the appeal with the Chief Clerk of the commission.

If you have any questions or require any additional information, please contact the Tax Relief for Pollution Control Property Program at (512) 239-3100.

Sincerely,

David Greer
Team Leader, Pollution Prevention

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

USE DETERMINATION

The Texas Commission on Environmental Quality has reviewed Use Determination Application, 07-11926, filed by:

NAVASOTA WHARTON ENERGY PARTNERS LP
COLORADO BEND
3821 S STATE HWY 60
WHARTON TX 77488

The pollution control property/project listed in the Use Determination Application is:

This facility has four thermally efficient heat recovery steam generators (HRSGs) and two steam turbines. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

The outcome of the review is:

A 100% positive use determination for the four Heat Recovery Steam Generators. This equipment is considered to be pollution control equipment and was installed to meet or exceed federal or state regulations.

A negative determination is issued for the two steam turbines. The use of the steam turbines does not provide an environmental benefit at the site. The steam turbines are not considered to be pollution control equipment.

Executive Director

May. 1. 2008
Date

TAX RELIEF FOR POLLUTION CONTROL PROPERTY: TECHNICAL REVIEW DOCUMENT

Reviewed By: RLH App. No.: 07 - 11926 Review Start Date: 4/8/2008

Company Name: NAVASOTA WHARTON ENERGY PARTNERS LP
Facility Name: COLORADO BEND
County: WHARTON Outstanding Fees: N
Batch/Voucher Number:B500028

ADMINISTRATIVE REVIEW

Administrative Complete Date:4/8/2008

TIER LEVEL
What Tier is this application? The application was filed as a Tier IV application. Is this the appropriate level?

The property listed on this application, Heat Recovery Steam Generators and a steam turbine are items B8 and B10 on the Equipment and Categories List. This application was filed as a Tier IV. Tier IV is the appropriate level for this application.

RELEVANT RULE, REGULATION, OR STATUTORY PROVISION
The rule listed in the application is: 40 CFR 60.44Da
The appropriate rule is: 40 CFR 60.44Da

Explain why this is the appropriate rule?

40 CFR 60.Subpart DA: Standards of Performance for New Stationary Sources. Standards of performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978. This is an appropriate rule.

BRIEF DESCRIPTION OF PROPERTY
The property is described as:

This facility has four thermally efficient heat recovery steam generators (HRSGs) and two steam turbines. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

Is an adequate description and purpose of the property provided? Does it list the anticipated environmental benefits? Are sketches and flow diagrams provided if needed?

An adequate description of the property was provided, and the purpose of the property was listed. The anticipated environmental benefit is listed. Sketches and flow diagrams were provided.

DECISION FLOWCHART(30 TAC 17.15(a))
Mark the appropriate boxes: Box 3 Box 5 Box 6(IV) Y Box 10(III) Box 12(I) Box 13(II)
PART B DECISION FLOWCHART (17.15(b))
Mark the appropriate boxes: Box 1Y Box 2 Y Box 3 Y

Describe how the property flowed through the Decision Flowchart:

The Heat Recovery Steam Generators (HRSGs) are listed on Part B of the Equipment & Categories List as item B-8. As Part B equipment the HRSGs leave the Decision Flow Chart at Box 6 and pass through Box 1 of the Part B Decision Flow Chart with a yes answer. Since the use

of HRSGs provide an environmental benefit of reduced NOx emissions at the site there is a yes answer for Box 2. Since there is a reduction in NOx emissions there is an environmental rule which is being met, so there is a yes answer to Box 3. The steam turbine passes through Box 1 on the Part B Decision Flow Chart with a yes answer. Since the use of the steam turbine does not provide an environmental benefit at the site a no answer is the result of Box 2. The steam turbine is not eligible for a positive determination.

TIER III or IV APPLICATIONS

Does your calculation agree with the applicants?

No. The application contains a proposed formula for calculating the pollution control value of the HRSGs and the steam turbine. The formula is outcome determinative, and its focus is not on the pollution control aspect of the property. The Executive Director disagrees with this formula.

PROPERTY CATEGORIES AND COSTS

Is the table completed correctly? Has the applicant certified that all listed property became taxable for the first time after January 1, 1994? Is all information necessary for conducting the technical review included.

The table was completed correctly. The applicant certified that all listed property became taxable for the first time after January 1, 1994. All the information necessary for conducting the technical review was included on the application.

TECHNICAL DEFICIENCIES

Is the application complete as received: Y If the application was not administratively complete explain below when justifying the final decision in the final determination section. If the application was not technically complete then:

Provide the language to be used in the Notice of Deficiency (NOD) letter:

Summarize the NOD response:

Provide the language used in the second NOD letter:

Summarize the second NOD response:

Provide the language used in the thied NOD letter:

Summarize the third NOD response:

FINAL DETERMINATION

If the property description has been summarized enter the detailed property description:

This facility has four thermally efficient heat recovery steam generators (HRSGs) and two steam

turbines. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

Provide the reason for your final determination:

The Heat Recovery Steam Generators meet all of the requirements of Chapter 17. A positive use determination based on the most appropriate formula should be issued for the Heat Recovery Steam Generators. The most appropriate formula has been determined by the Executive Director. A negative determination should be issued for the steam turbine. The use of the steam turbine does not result in there being an environmental benefit at the site.

Provide the language for the final determination.

A positive use determination of 100% for the four Heat Recovery Steam Generators. A negative determination is issued for the steam turbine. The use of the steam turbine does not provide an environmental benefit at the site. The steam turbine is not considered to be pollution control equipment.

Highlight the required signatures and establish the appropriate due dates.

Reviewed: Ronald Hebert **Date Signed:** 5/1/08

Peer Reviewed: Gary McAuliffe **Date Signed:** 5-1-08

Team Leader: [illegible] **Date Signed:** 5/1/08

Section Manager: [illegible] **Date Signed:** MAY 1, 2008

Division Director: [illegible] **Date Signed:** MAY 1, 2008

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

May 1, 2008

TENASKA INC
DAVID D JOHNSON
1044 N 115 ST #400
OMAHA, NE 68154 4446

This letter is to inform you that on 5/1/2008, the technical review of Use Determination Application 07-11914 was completed. This application is for:

TENASKA GATEWAY PARTNERS LTD
TENASKA GATEWAY GENERATION STATION
SH 315, PO BOX 697
MOUNT ENTERPRISE, TX 75681 0697

The use determination is included with this letter. In order to request an exemption, a copy of this Use Determination, along with a completed exemption request form #50-248 (can be found at www.cpa.state.tx.us), must be provided to the Chief Appraiser of the appropriate appraisal district. This request must be made by April 30.

House Bill 3121, enacted during the 77th Legislative Session, established a process for appealing a use determination. The Texas Commission on Environmental Quality (TCEQ) rules that implement the appeals process are at 30 TAC 17.25. Pursuant to 17.25(a)(1), an appeal must be filed within 20 days of receipt of the use determination. Should you choose to appeal the use determination, please submit a copy of your appeal to the TCEQ Tax Relief for Pollution Control Property program at the time of filing the appeal with the Chief Clerk of the commission.

If you have any questions or require any additional information, please contact the Tax Relief for Pollution Control Property Program at (512) 239-3100.

Sincerely,

David Greer
Team Leader, Pollution Prevention

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

USE DETERMINATION

The Texas Commission on Environmental Quality has reviewed Use Determination Application, 07-11914, filed by:

TENSKA GATEWAY PARTNERS LTD
TENASKA GATEWAY GENERATION STATION
SH 315, PO BOX 697
MOUNT ENTERPRISE TX 75681

The pollution control property/project listed in the Use Determination Application is:

This facility has three combustion turbine generators coupled with three thermally efficient heat recovery steam generators (HRSGs) and one enhanced steam turbine. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

The outcome of the review is:

A 100% positive use determination for the three Heat Recovery Steam Generators. This equipment is considered to be pollution control equipment and was installed to meet or exceed federal or state regulations.

A negative determination is issued for the steam turbine. The use of the steam turbine does not provide an environmental benefit at the site. The steam turbine is not considered to be pollution control equipment.

Executive Director

May. 1. 2008
Date

TAX RELIEF FOR POLLUTION CONTROL PROPERTY: TECHNICAL REVIEW DOCUMENT

Reviewed By: RLH App. No.: 07 - 11914 Review Start Date: 4/8/2008

Company Name: TENSKA GATEWAY PARTNERS LTD
Facility Name: TENASKA GATEWAY GENERATION STATION
County: RUSK Outstanding Fees: N
Batch/Voucher Number:B99788

ADMINISTRATIVE REVIEW

Administrative Complete Date:4/8/2008

TIER LEVEL
What Tier is this application? The application was filed as a Tier IV application. Is this the appropriate level?

The property listed on this application, Heat Recovery Steam Generators and a steam turbine are items B8 and B10 on the Equipment and Categories List. This application was filed as a Tier IV. Tier IV is the appropriate level for this application.

RELEVANT RULE, REGULATION, OR STATUTORY PROVISION
The rule listed in the application is: 40 CFR 60.44Da
The appropriate rule is: 40 CFR 60.44Da

Explain why this is the appropriate rule?

40 CFR 60.Subpart DA: Standards of Performance for New Stationary Sources. Standards of performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978. This is an appropriate rule.

BRIEF DESCRIPTION OF PROPERTY
The property is described as:

This facility has three combustion turbine generators coupled with three thermally efficient heat recovery steam generators (HRSGs). This application is a Tier IV application seeking a partial use determination for the three HRSGs and the enhanced steam turbines. To generate the equivalent amount of power using combustion turbine they would have needed to install a Selective Catalytic Reduction System.The application requests a partial determination.

Is an adequate description and purpose of the property provided? Does it list the anticipated environmental benefits? Are sketches and flow diagrams provided if needed?

An adequate description of the property was provided, and the purpose of the property was listed. The anticipated environmental benefit is listed. Sketches and flow diagrams were provided.

DECISION FLOWCHART(30 TAC 17.15(a))
Mark the appropriate boxes: Box 3 Box 5 Box 6(IV) Y Box 10(III) Box 12(I) Box 13(II)
PART B DECISION FLOWCHART (17.15(b))
Mark the appropriate boxes: Box 1Y Box 2 Y Box 3 Y

Describe how the property flowed through the Decision Flowchart:

The Heat Recovery Steam Generators (HRSGs) are listed on Part B of the Equipment &

Categories List as item B-8. As Part B equipment the HRSGs leave the Decision Flow Chart at Box 6 and pass through Box 1 of the Part B Decision Flow Chart with a yes answer. Since the use of HRSGs provide an environmental benefit of reduced NOx emissions at the site there is a yes answer for Box 2. Since there is a reduction in NOx emissions there is an environmental rule which is being met, so there is a yes answer to Box 3. The steam turbine passes through Box 1 on the Part B Decision Flow Chart with a yes answer. Since the use of the steam turbine does not provide an environmental benefit at the site a no answer is the result of Box 2. The steam turbine is not eligible for a positive determination.

TIER III or IV APPLICATIONS

Does your calculation agree with the applicants?

No. The application contains a proposed formula for calculating the pollution control value of the HRSGs and the steam turbine. The formula is outcome determinative, and its focus is not on the pollution control aspect of the property. The Executive Director disagrees with this formula.

PROPERTY CATEGORIES AND COSTS

Is the table completed correctly? Has the applicant certified that all listed property became taxable for the first time after January 1, 1994? Is all information necessary for conducting the technical review included.

The table was completed correctly. The applicant certified that all listed property became taxable for the first time after January 1, 1994. All the information necessary for conducting the technical review was included on the application.

TECHNICAL DEFICIENCIES

Is the application complete as received: Y If the application was not administratively complete explain below when justifying the final decision in the final determination section. If the application was not technically complete then:

Provide the language to be used in the Notice of Deficiency (NOD) letter:

Summarize the NOD response:

Provide the language used in the second NOD letter:

Summarize the second NOD response:

Provide the language used in the thied NOD letter:

Summarize the third NOD response:

FINAL DETERMINATION

If the property description has been summarized enter the detailed property description:

This facility has three combustion turbine generators coupled with three thermally efficient heat recovery steam generators (HRSGs). This application is a Tier IV application seeking a partial use determination for the three HRSGs and the enhanced steam turbines. To generate the equivalent amount of power using combustion turbine they would have needed to install a Selective Catalytic Reduction System. The application requests a partial determination.

Provide the reason for your final determination:

The Heat Recovery Steam Generators meet all of the requirements of Chapter 17. A positive use determination based on the most appropriate formula should be issued for the Heat Recovery Steam Generators. The most appropriate formula has been determined by the Executive Director. A negative determination should be issued for the steam turbine. The use of the steam turbine does not result in there being an environmental benefit at the site.

Provide the language for the final determination.

A positive use determination of 100% for the three Heat Recovery Steam Generators. A negative determination is issued for the steam turbine. The use of the steam turbine does not provide an environmental benefit at the site. The steam turbine is not considered to be pollution control equipment.

Highlight the required signatures and establish the appropriate due dates.

Reviewed: Ronald Hebbets **Date Signed:** 5/1/2008

Peer Reviewed: Gary McArthur **Date Signed:** 5/1/2008

Team Leader: [illegible] **Date Signed:** 5/1/08

Section Manager: [illegible] **Date Signed:** MAY 1 2008

Division Director: [illegible] **Date Signed:** MAY 1 2008

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

May 1, 2008

DUFF & PHELPS LLC
DENNIS DEEGEAR
919 CONGRESS #1450
AUSTIN, TX 78701

This letter is to inform you that on 5/1/2008, the technical review of Use Determination Application 07-11971 was completed. This application is for:

BORGER ENERGY ASSOCIATES LP
BORGER ENERGY BLACKHAWK STATION
119 N. SPUR CO-GEN PLACE
BORGER, TX 79008

The use determination is included with this letter. In order to request an exemption, a copy of this Use Determination, along with a completed exemption request form #50-248 (can be found at www.cpa.state.tx.us), must be provided to the Chief Appraiser of the appropriate appraisal district. This request must be made by April 30.

House Bill 3121, enacted during the 77th Legislative Session, established a process for appealing a use determination. The Texas Commission on Environmental Quality (TCEQ) rules that implement the appeals process are at 30 TAC 17.25. Pursuant to 17.25(a)(1), an appeal must be filed within 20 days of receipt of the use determination. Should you choose to appeal the use determination, please submit a copy of your appeal to the TCEQ Tax Relief for Pollution Control Property program at the time of filing the appeal with the Chief Clerk of the commission.

If you have any questions or require any additional information, please contact the Tax Relief for Pollution Control Property Program at (512) 239-3100.

Sincerely,

David Greer
Team Leader, Pollution Prevention

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

USE DETERMINATION

The Texas Commission on Environmental Quality has reviewed Use Determination Application, 07-11971, filed by:

BORGER ENERGY ASSOCIATES LP
BORGER ENERGY BLACKHAWK STATION
119 N. SPUR CO-GEN PLACE
BORGER TX 79008

The pollution control property/project listed in the Use Determination Application is:

This facility has two thermally efficient heat recovery steam generators (HRSGs). This application is a Tier IV application seeking a partial use determination for the two HRSGs.

The outcome of the review is:

A 100% positive use determination for the two Heat Recovery Steam Generators. This equipment is considered to be pollution control equipment and was installed to meet or exceed federal or state regulations.

Executive Director

May 1 2008
Date

TAX RELIEF FOR POLLUTION CONTROL PROPERTY: TECHNICAL REVIEW DOCUMENT

Reviewed By: RLH App. No.: 07 - 11971 Review Start Date: 4/8/2008

Company Name: BORGER ENERGY ASSOCIATES LP
Facility Name: BORGER ENERGY BLACKHAWK STATION
County: HUTCHINSON Outstanding Fees: N
Batch/Voucher Number:B500156

ADMINISTRATIVE REVIEW

Administrative Complete Date:4/8/2008

TIER LEVEL
What Tier is this application? The application was filed as a Tier IV application. Is this the appropriate level?

The property listed on this application, Heat Recovery Steam Generators, is item B8 on the Equipment and Categories List. This application was filed as a Tier IV. Tier IV is the appropriate level for this application.

RELEVANT RULE, REGULATION, OR STATUTORY PROVISION
The rule listed in the application is: 40 CFR 60.44Da
The appropriate rule is: 40 CFR 60.44Da

Explain why this is the appropriate rule?

40 CFR 60.Subpart DA: Standards of Performance for New Stationary Sources. Standards of performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978. This is an appropriate rule.

BRIEF DESCRIPTION OF PROPERTY
The property is described as:

This facility has two thermally efficient heat recovery steam generators (HRSGs). This application is a Tier IV application seeking a partial use determination for the two HRSGs.

Is an adequate description and purpose of the property provided? Does it list the anticipated environmental benefits? Are sketches and flow diagrams provided if needed?

An adequate description of the property was provided, and the purpose of the property was listed. The anticipated environmental benefit is listed. Sketches and flow diagrams were provided.

DECISION FLOWCHART(30 TAC 17.15(a))
Mark the appropriate boxes: Box 3 Box 5 Box 6(IV) Y Box 10(III) Box 12(I) Box 13(II)
PART B DECISION FLOWCHART (17.15(b))
Mark the appropriate boxes: Box 1Y Box 2 Y Box 3 Y

Describe how the property flowed through the Decision Flowchart:

Since the property is listed on Part B of the Equipment & Categories List this property leaves the Decision Flow Chart at Box 6. It passes through Box 1 of the Part B Decision Flow Chart with a yes answer. The use of this property at a combined cycle plant, as opposed to having a simple cycle plant, provides an environmental benefit of reduced NOx emissions at the site. So there is a

Yes answer for Box 2, Since there is a reduction in NOx emissions there is an environmental rule which is being met so there is a yes answer to Box 3.

TIER III or IV APPLICATIONS

Does your calculation agree with the applicants?

No. The application contains a proposed formula for calculating the pollution control value of the HRSGs and the steam turbine. The formula is outcome determinative, and its focus is not on the pollution control aspect of the property. The Executive Director disagrees with this formula.

PROPERTY CATEGORIES AND COSTS

Is the table completed correctly? Has the applicant certified that all listed property became taxable for the first time after January 1, 1994? Is all information necessary for conducting the technical review included.

The table was completed correctly. The applicant certified that all listed property became taxable for the first time after January 1, 1994. All the information necessary for conducting the technical review was included on the application.

TECHNICAL DEFICIENCIES

Is the application complete as received: Y If the application was not administratively complete explain below when justifying the final decision in the final determination section. If the application was not technically complete then:

Provide the language to be used in the Notice of Deficiency (NOD) letter:

Summarize the NOD response:

Provide the language used in the second NOD letter:

Summarize the second NOD response:

Provide the language used in the thied NOD letter:

Summarize the third NOD response:

FINAL DETERMINATION

If the property description has been summarized enter the detailed property description:

This facility has two thermally efficient heat recovery steam generators (HRSGs). This application is a Tier IV application seeking a partial use determination for the two HRSGs.

Provide the reason for your final determination:

The Heat Recovery Steam Generators meet all of the requirements of Chapter 17. A positive use determination based on the most appropriate formula should be issued for the Heat Recovery Steam Generators. The most appropriate formula has been determined by the Executive Director.

Provide the language for the final determination.

A positive use determination of 100% for the two Heat Recovery Steam Generators.

Highlight the required signatures and establish the appropriate due dates.

Reviewed: Ronald Hatfield **Date Signed:** 5/1/08

Peer Reviewed: Gary McArthur **Date Signed:** 5-1-08

Team Leader: [illegible] **Date Signed:** 5/1/08

Section Manager: [illegible] **Date Signed:** MAY 1 2008

Division Director: [illegible] **Date Signed:** MAY 1 2008

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

May 1, 2008

CALPINE/DOW
JUSTIN HYLAND/LEO SCHERRER
717 TEXAS AVE
HOUSTON, TX 77002

This letter is to inform you that on 5/1/2008, the technical review of Use Determination Application 07-11994 was completed. This application is for:

FREEPORT ENERGY CENTER LP
FREEPORT ENERGY CENTER LP
2301 N BRAZOSPORT BLVD
FREEPORT, TX 77451

The use determination is included with this letter. In order to request an exemption, a copy of this Use Determination, along with a completed exemption request form #50-248 (can be found at www.cpa.state.tx.us), must be provided to the Chief Appraiser of the appropriate appraisal district. This request must be made by April 30.

House Bill 3121, enacted during the 77th Legislative Session, established a process for appealing a use determination. The Texas Commission on Environmental Quality (TCEQ) rules that implement the appeals process are at 30 TAC 17.25. Pursuant to 17.25(a)(1), an appeal must be filed within 20 days of receipt of the use determination. Should you choose to appeal the use determination, please submit a copy of your appeal to the TCEQ Tax Relief for Pollution Control Property program at the time of filing the appeal with the Chief Clerk of the commission.

If you have any questions or require any additional information, please contact the Tax Relief for Pollution Control Property Program at (512) 239-3100.

Sincerely,

David Greer
Team Leader, Pollution Prevention

Buddy Garcia, *Chairman*
Larry R. Soward, *Commissioner*
Bryan W. Shaw, Ph.D., *Commissioner*
Glenn Shankle, *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

USE DETERMINATION

The Texas Commission on Environmental Quality has reviewed Use Determination Application, 07-11994, filed by:

FREEPORT ENERGY CENTER LP
FREEPORT ENERGY CENTER LP
2301 N BRAZOSPORT BLVD
FREEPORT TX 77451

The pollution control property/project listed in the Use Determination Application is:

This facility has thermally efficient heat recovery steam generators (HRSGs) and steam turbines. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

The outcome of the review is:

A 100% positive use determination for the Heat Recovery Steam Generators. This equipment is considered to be pollution control equipment and was installed to meet or exceed federal or state regulations.

A negative determination is issued for the steam turbines. The use of the steam turbines does not provide an environmental benefit at the site. The steam turbines are not considered to be pollution control equipment.

Executive Director

May 2 2008
Date

TAX RELIEF FOR POLLUTION CONTROL PROPERTY: TECHNICAL REVIEW DOCUMENT

Reviewed By: RLH App. No.: 07 - 11994 Review Start Date: 4/8/2008

Company Name: FREEPORT ENERGY CENTER LP
Facility Name: FREEPORT ENERGY CENTER LP
County: BRAZORIA Outstanding Fees: N
Batch/Voucher Number:B500289

ADMINISTRATIVE REVIEW

Administrative Complete Date:4/8/2008

TIER LEVEL
What Tier is this application? The application was filed as a Tier IV application. Is this the appropriate level?

The property listed on this application, Heat Recovery Steam Generators and a steam turbine are items B8 and B10 on the Equipment and Categories List. This application was filed as a Tier IV. Tier IV is the appropriate level for this application.

RELEVANT RULE, REGULATION, OR STATUTORY PROVISION
The rule listed in the application is: 40 CFR 60.44Da
The appropriate rule is: 40 CFR 60.44Da

Explain why this is the appropriate rule?

40 CFR 60.Subpart DA: Standards of Performance for New Stationary Sources. Standards of performance for Electric Utility Steam Generating Units for Which Construction is Commenced after September 18, 1978. This is an appropriate rule.

BRIEF DESCRIPTION OF PROPERTY
The property is described as:

This facility has thermally efficient heat recovery steam generators (HRSGs) and steam turbines. This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

Is an adequate description and purpose of the property provided? Does it list the anticipated environmental benefits? Are sketches and flow diagrams provided if needed?

An adequate description of the property was provided, and the purpose of the property was listed. The anticipated environmental benefit is listed. Sketches and flow diagrams were provided.

DECISION FLOWCHART(30 TAC 17.15(a))
Mark the appropriate boxes: Box 3 Box 5 Box 6(IV) Y Box 10(III) Box 12(I) Box 13(II)
PART B DECISION FLOWCHART (17.15(b))
Mark the appropriate boxes: Box 1Y Box 2 Y Box 3 Y

Describe how the property flowed through the Decision Flowchart:

Since the property is listed on Part B of the Equipment & Categories List this property leaves the Decision Flow Chart at Box 6. It passes through Box 1 of the Part B Decision Flow Chart with a yes answer. The use of this property at a combined cycle plant, as opposed to having a simple

cycle plant, provides an environmental benefit of reduced NOx emissions at the site. So there is a Yes answer for Box 2, Since there is a reduction in NOx emissions there is an environmental rule which is being met so there is a yes answer to Box 3. The steam turbine passes through Box 1 on the Part B Decision Flow Chart with a yes answer. Since the use of the steam turbine does not provide an environmental benefit at the site a no answer is the result of Box 2. The steam turbine is not eligible for a positive determination.

TIER III or IV APPLICATIONS

Does your calculation agree with the applicants?

No. The application contains a proposed formula for calculating the pollution control value of the HRSGs and the steam turbine. The formula is outcome determinative, and its focus is not on the pollution control aspect of the property. The Executive Director disagrees with this formula.

PROPERTY CATEGORIES AND COSTS

Is the table completed correctly? Has the applicant certified that all listed property became taxable for the first time after January 1, 1994? Is all information necessary for conducting the technical review included.

The table was completed correctly. The applicant certified that all listed property became taxable for the first time after January 1, 1994. All the information necessary for conducting the technical review was included on the application.

TECHNICAL DEFICIENCIES

Is the application complete as received: Y If the application was not administratively complete explain below when justifying the final decision in the final determination section. If the application was not technically complete then:

Provide the language to be used in the Notice of Deficiency (NOD) letter:

Summarize the NOD response:

Provide the language used in the second NOD letter:

Summarize the second NOD response:

Provide the language used in the thied NOD letter:

Summarize the third NOD response:

FINAL DETERMINATION

If the property description has been summarized enter the detailed property description:

This facility has thermally efficient heat recovery steam generators (HRSGs) and steam turbines.

This application is a Tier IV application seeking a partial use determination for the HRSGs and the enhanced steam turbines.

Provide the reason for your final determination:

The Heat Recovery Steam Generators meet all of the requirements of Chapter 17. A positive use determination based on the most appropriate formula should be issued for the Heat Recovery Steam Generators. The most appropriate formula has been determined by the Executive Director. A negative determination should be issued for the steam turbine. The use of the steam turbine does not result in there being an environmental benefit at the site.

Provide the language for the final determination.

A positive use determination of 100% for the Heat Recovery Steam Generators. A negative determination is issued for the steam turbine. The use of the steam turbine does not provide an environmental benefit at the site. The steam turbine is not considered to be pollution control equipment.

Highlight the required signatures and establish the appropriate due dates.

Reviewed: **Date Signed:** 5/1/8

Peer Reviewed: **Date Signed:** 5-1-08

Team Leader: **Date Signed:** 5/1/08

Section Manager: **Date Signed:** MAY 1 2008

Division Director: **Date Signed:** MAY 1 2008

ATTACHMENT F

Espey, Huston & Associates, Inc.
Engineering & Environmental Consultants

Document No. 940312
EH&A Job No. 15495

APPLICATION FOR A TNRCC/PSD AIR QUALITY CONSTRUCTION PERMIT FOR THE CLEBURNE COGENERATION PROJECT CLEBURNE, TEXAS

Prepared for:

Tenaska Power Partners, L.P.
1044 N. 115 Street, Suite 400
Omaha, Nebraska 68154-4446

Prepared by:

Espey, Huston & Associates, Inc.
P.O. Box 519
Austin, Texas 78767

STATE OF TEXAS
RUBEN I. VELASQUEZ
69126
REGISTERED PROFESSIONAL ENGINEER

Ruben I. Velasquez
6-20-94

June 1994

P.O. Box 519 • Austin, Texas 78767-0519
206 Wild Basin Road, Suite 300 (78746-3343)
(512) 327-6840 TEL • (512) 327-2453 FAX

A PLANET PACIFIC COMPANY

TENASKA POWER PARTNERS, L.P.

1044 N. 115 Street, Suite 400
Omaha, Nebraska 68154-4446

Telephone: (402) 691-9500
Fax: (402) 691-9526

June 17, 1994

Mr. Jeff Saitas, P.E.
Director, New Source Review Program
Office of Air Quality
Texas Natural Resource Conservation Commission
P.O. Box 13087
Austin, Texas 78711-3087

RE: Texas Natural Resource Conservation Commission (TNRCC) and Prevention of Significant Deterioration (PSD) Permit Application for the Tenaska Cleburne Cogeneration Project, Cleburne, Johnson County, Texas

Dear Mr. Saitas:

Enclosed please find one copy of our TNRCC/PSD application for a permit to construct our Cleburne Cogeneration Project prepared by Espey, Huston & Associates, Inc. (EH&A) on behalf of Tenaska Power Partners, L.P. The project will be located north of the city of Cleburne, Texas and will consist of two cogeneration systems which will produce a combined nominal net plant output of 500 MWe of electricity. The project will utilize the Best Available Control Technology (BACT) in controlling emissions and will comply with all the rules and regulations of both the TNRCC and the EPA. An air quality analysis of the project will be submitted after a preliminary determination has been made by the TNRCC air quality staff that the emissions calculations and controls proposed as BACT are acceptable. A new business entity (Tenaska IV Texas Partners, Ltd.) in the process of being formed to own and operate the new facility as noted on the enclosed TNRCC Air Quality PI-1, General Application Form.

Thank you for your consideration of this request. A check for the permit fee of $75,000 is enclosed. Please note that Tenaska requires approval of the TNRCC air quality permit by December 1994 in order to meet financial and contractual obligations to the project.

TENASKA, INC., Managing General Partner
EMPECO II, INC., General Partner
(a subsidiary of Continental Energy Services, Inc.)

TENASKA

Therefore, your expeditious review of this application would be very much appreciated. If you should have any questions or comments regarding this application, please contact Mr. Ruben Velasquez of EH&A at (512) 329-8342, extension 9578 or me at (402) 691-9500.

Very truly yours,

Tenaska Power Partners, L.P.
By: Tenaska, Inc., Managing Partner

By:
Michael C. Lebens
Vice President

MCL:cw

Enclosure

cc: Ms. Jole Luehrs, U.S. Environmental Protection Agency, Region 6 Office
Mr. Melvin Lewis, TNRCC Region 4 Office
Mr. Ruben I. Velasquez, P.E., Espey, Huston & Associates, Inc.

Espey, Huston & Associates, Inc.

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Espey, Huston & Associates, Inc.

SECTION 1.0

INTRODUCTION AND GENERAL DESCRIPTION

1.0 INTRODUCTION AND GENERAL DESCRIPTION

Tenaska IV Texas Partners, Ltd. (Tenaska) is proposing to construct a cogeneration project, hereafter referred to as "project", in Cleburne, Johnson County, Texas. The plant site will be located in the Cleburne Industrial Park north of the intersection of Texas Highways 171 and 174. The project will consist of two gas turbine electric generating units, each of which exhausts into a duct burner-fired heat recovery steam generator (HRSG). These units will be primarily natural gas-fired with diesel fuel backup for the gas turbines. In addition, two steam turbine generators will be constructed for added capacity. The plant will produce a combined nominal net output of 500 MWe of electricity. The electric power generated by the proposed cogeneration project will be sold to an electric utility company. The steam produced will be sold to an adjacent industrial facility. An auxiliary boiler will also be installed to serve as a backup source for steam production for the adjacent industrial facility. The auxiliary boiler will also be primarily natural gas-fired with diesel fuel backup.

The project will require that Tenaska obtain an air quality permit from the Texas Natural Resource Conservation Commission (TNRCC) and a Federal Prevention of Significant Deterioration (PSD) permit prior to commencement of construction. Tenaska will make use of the Best Available Control Technology (BACT) in controlling emissions from this project. The results of atmospheric dispersion modeling of air contaminant emissions, which will be submitted in a separate document, will demonstrate that emissions from the proposed project will not cause or contribute to an exceedance of Federal ambient air quality standards, state property-line standards or screening levels.

This document constitutes Tenaska's application to the TNRCC for a permit to construct the proposed project. As the TNRCC is delegated authority for the review and issuance of PSD permits, the required information for PSD review is incorporated into this application. The sections that follow contain the descriptions, data, analyses, drawings, and other information required by the TNRCC to complete its review of this application. The section numbers are related to the sections referenced in the TNRCC Form PI-1, General Application (see Section 2.0) followed by additional information required to address PSD requirements.

This application has been prepared based on information and guidance from the TNRCC at a pre-application meeting with the TNRCC on 23 March 1994 and a pre-modeling meeting with the TNRCC on 27 April 1994. A complete modeling analysis will be provided at a later date as a separate document submitted in support of this application. This modeling will be based on a preliminary review by the TNRCC of the protocol to be used for modeling and the project's BACT and emission rate calculations.

The project will be built in two phases. Construction of the first gas turbine/HRSG unit will commence upon issuance of the permit. Construction of the second gas turbine/HRSG will commence after a power purchase agreement is signed for the additional power produced. It is important to note that Tenaska requires approval of the TNRCC air quality permit by November 1994 in order to meet financial and contractual obligations. Therefore, an expeditious review of this application will be appreciated.

Espey, Huston & Associates, Inc.

SECTION 2.0

FORM PI-1

FORM PI-1, GENERAL APPLICATION -- AIR QUALITY PERMIT

TNRCC

A PERMIT TO CONSTRUCT MUST BE APPROVED BEFORE ANY ACTUAL WORK IS BEGUN ON THE FACILITY. This is not a stand alone document. Please refer to the "Form PI-1, Permit Application Instructions" manual (Instructions) for specific details to complete this application. Please print or type all information. All information requested herein must be completed and submitted before public notification procedures may be authorized. Please contact the CORE Section of the New Source Review Program with any questions at 512/908-1000 (FAX No. 512/908-1300). Written inquiries may be addressed to: Texas Natural Resource Conservation Commission, Office of Air Quality, New Source Review Program, P.O. Box 13087, Austin TX 78711-3087.

V E R Y I M P O R T A N T !

- Is CONFIDENTIAL information being submitted with this application? [ ]-YES [X]-NO
  If YES, is each "confidential" page so marked in big red letters? [ ]-YES [ ]-NO
- Has a CORE checklist been attached to this application? ..... [X]-YES [ ]-NO
- Is this application in response to, or related in any way to, a Notice of Violation at this location? [ ]-YES [X]-NO. If YES, date of Notice of Violation: _____
  Also, if YES, pursuant to Rule: _____

Please furnish the following information pertaining to this facility SITE:

1. Please estimate the net number of new jobs which will be created in the community as a result of the operation of the facility authorized by this application: 25
2. Name of elected State Senator: Jane Nelson
3. Name of elected State Representative: Bernard Ericson

Please furnish the following information pertaining to Compliance History:

Submit a 5-year Compliance History in accordance with Regulation VI, Rule 116.120-116.126 for all facilities classified in Sections V.C and V.D of Form PI-1 below.

I. TYPE OF APPLICATION: [X]-CONSTRUCTION PERMIT [ ]-AMENDMENT, Permit No. _____

A. PERMIT ISSUED TO: Tenaska Power Partners, L.P.
(Entity legally responsible for permit; i.e., Owner or Operator of the facility)
Permittee's Texas State Comptroller's Tax ID No.: not yet received
Permittee's address (Person, Title, Address): 1044 N. 115 Street, Suite 400, Omaha, Nebraska 68154-4446
Telephone: (402) 691-9500 FAX: (402) 691-9530
Permittee's Technical Contract (Person, Title, Address): Michael C. Lebens, Vice President of Engineering, Tenaska Power Partners, L.P., 1044 N. 115 Street, Suite 400, Omaha, Nebraska 68154-4446
Telephone: (402) 691-9500 FAX: (402) 691-9530

B. OWNER OF FACILITY: Tenaska IV Texas Partners, LTD.
(If different from permittee; include names of proprietor/general partner(s) if applicable)
Owner's Texas State Comptroller's Tax ID No.: not yet received
Owner's address (Person, Title, Address): 1044 N. 115 Street, Suite 400, Omaha, Nebraska 68154-4446

C. Principal Company Product or Business: Cogeneration of steam and electricity
Plant SIC Code: 4911

I. FACILITY PHYSICAL LOCATION:

A. Name of plant or site: Tenaska Cleburne Cogeneration Project
B. Street Address: Cleburne Industrial Park north of the intersection of Texas Highways 171 and 174
C. Nearest City: Cleburne County: Johnson Site Zip Code: 76031
D. Latitude: 32 ° 23 ' 57 "N Longitude: 97 ° 24 ' 29 "W (must be to nearest second)
E. Plant Site TNRCC Air Quality Account Number: ____-_____-__

III. FACILITY TYPE AND OPERATING SCHEDULE:

A. Name of facility to be permitted: Tenaska Cleburne Cogeneration Project
B. Facility Type (Check One): [X] Permanent, [ ] Portable.
C. Facility Operating Schedule: (24) Hours/day; (7) Days/week; (52) Weeks/year
(___) Seasonal - explain: _____
D. Start Dates (Proposed/Actual): Construction: 1 / 1 / 95 (P/A) P
Operation: 1 / 1 / 97 (P/A) P

IV. FACILITY CLASSIFICATION (Check only one block):

A. [X] New Permitted Facility - New grass roots facility at this location.
B. [ ] New Permitted Facility - Modification of existing non-permitted Facility.
C. [ ] Amendment to Permitted Facility. Permit No(s). _____
D. [ ] Change in Location of Permitted Facility. Permit No(s). _____
Location of Present Facility: _____

J. COMPLIANCE HISTORY (See attached Supplemental Information Sheet):

A. [ ] Exemption claimed under Rule 116.121, or
B. [ ] Existing Site => 5 years old. TNRCC will compile Compliance History, or
C. [X] New Site (This is a new grassroots site with no operating history), or
D. [ ] Existing Site < 5 years old.

If "C" or "D", does applicant have similar facilities in Texas? [X]-YES [ ]-NO.
1. If YES, list TNRCC Air Quality Account No.(s): 1A-0045-F (Tenaska Affiliate) Tenaska III Texas Partners
2. If NO, attached one of the following:
   a. [ ] Compliance History for similar sites in other States. If none, then:
   b. [ ] Compliance History as required by Regulation VI, Rule 116.122(b).

(Over)

Version 10/22/93

VI. SUBMIT THE FOLLOWING GENERAL INFORMATION:

A. Submit a current area map as specified in the Instructions.
Are any schools located within 3000 feet of this facility? [ ]-YES [X]-NO.

B. Submit a plot plan of the plant property as specified in the Instructions.

C. Submit emission data, including fugitive emissions and stack parameters, on Table 1(a). Attach emission calculations and information showing how emissions were determined. See Instructions for further details.

D. Submit an analysis of Best Available Control Technology, including the estimated installed capital and operating costs for all abatement equipment associated with the facility. See Instructions for further details.

V E R Y I M P O R T A N T !

E. **Franchise Tax.** Submit a copy of a Certificate of Good Standing from the State Comptroller's Office with each application if the permit is to be issued to a corporation. See Instructions if you are not a corporation or for further information.

F. **Permit Fee.** Enclose required fee, fee certification and estimated capital cost (Table 30); or furnish explanation why fee is not required. (See Regulation VI Rule 116.141.) A check for $75,000 is enclosed as the capital cost of the project will exceed $15,000,000.

VII. SUBMIT (A) PROCESS FLOW DIAGRAM, (B) PROCESS DESCRIPTION AND (C) MATERIAL BALANCE AS SPECIFIED IN THE INSTRUCTIONS (see Instructions concerning submittal of confidential information

VIII. GENERAL APPLICATION REQUIREMENTS:
Submit itemized information and/or analysis that will demonstrate that all general application requirements as specified in Rule 116.111 of TNRCC Regulation VI are met. Each requirement in Rule 116.111 must be addressed in this application. See Instructions for further details. Atmospheric dispersion modeling may be required as part of the air quality impact analysis per Rule 116.111(9).

Is this facility a MAJOR SOURCE/MODIFICATION with regard to one of the following:
1. §116.111(7) - Nonattainment ..... [ ]-YES [X]-NO
2. §116.111(8) - Prevention of Significant Deterioration [X]-YES [ ]-NO.

IX. APPEAL PROCESS:
Commission Rule 116.114(a)(3) should be consulted for the procedure to be used to appeal the failure of the agency to process an application within the prescribed time limits.

X. A copy of this application and all attachments must be sent by the applicant to the EPA Region 6 office in Dallas if PSD or Nonattainment Review is applicable in any form, the appropriate TNRCC Regional Office and to any local air pollution control program having jurisdiction. Copies of the application were sent to:

EPA Region 6 Office in Dallas ..... : [X]-YES [ ]-Not applicable.
TNRCC Regional Office (city) sent to: Region 4 - Arlington
Copies sent to these local programs: 1. _____
[X]-NOT APPLICABLE. 2. _____

XI. §116.110(d). PE Seal. Is the estimated capital cost of the project for which application is made greater than $2 million dollars? [X]-YES [ ]-NO

If YES, application must be submitted under seal of a Texas registered Professional Engineer, unless exemption is claimed pursuant to the Texas Engineering Practice Act.
[ ] - Exemption is claimed pursuant to Section _____ of the TEPA.

XII. I, Michael C Lesens - Vice President of Tenaska Inc, Managing Partner of Tenaska Power Partners, L.
(Name - Please print or type) (Title: Owner, Plant Manager, President, Vice-President, Environmental Director, etc.)
state that I have knowledge of the facts herein set forth and that the same are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Health & Safety Code (THSC), Chapter 382, Texas Clean Air Act, as amended, or any of the air quality Rules and Regulations of the Texas Natural Resource Conservation Commission or any local governmental ordinance or resolution enacted pursuant to the Texas Clean Air Act. I further state that I have read and understand Section 382.091, THSC, which defines CRIMINAL OFFENSES for certain violations, including intentionally or knowingly making or causing to be made false material statements or representations in this application, and Section 382.092, THSC, pertaining to CRIMINAL PENALTIES.

DATE 6/16/94 SIGNATURE _____

NOTE - ORIGINAL SIGNATURE IN INK IS REQUIRED.

Michael C Lesens

NOTE TO APPLICANT: ... labeled "Comments & Discussion" to further explain your action.

TNRCC

TEXAS NATURAL RESOURCE CONSERVATION COMMISSION
PERMITS DIVISION - CORE SECTION
AIR QUALITY PERMIT APPLICATION
ADMINISTRATIVE COMPLETENESS CHECKLIST

COMPANY Tenaska Power Partners, L.P. PROJ No.: _____ PROJ TYPE: _____ CORE ENGR: _____ RECORD No.: _____
REGION 4 COUNTY Johnson Tech. Contact: Michael C. Lebens, VP of Engineering Phone: (402)691-9500
DATE RECD by CORE: _____ Comments _____ DATE ADMIN COMP: _____
DATE RECD by TECH. ENGR: _____ Comments _____ TECH. ENGR: _____ TECHNICAL SECT.: _____

PI-1 REF	REQUIRED INFORMATION	Applicant use		<------ TNRCC use only -------> DATE ADMIN COMPLETE	NOT COMPLETE	NOTHING SUBMITTED	COMMENTS & DISCUSSION
	CONFIDENTIAL Information?(1)	X					[ ]YES [X]NO
	CONFIDENTIAL pages marked?	N/A					[ ]YES [ ]NO
	CORE Checklist attached	X	*				[X]YES [ ]NO
	NOV related notification	N/A					[ ]YES [X]NO
	Net number of new jobs created	X					
	Name of elected State Senator	X					
	Name of elected St. Representative	X					
I.	Type of Application	X	*				[X]PERMIT [ ]AMENDMENT
	A. Permittee Name, Tax ID & Addr.	X					
	Technical Contact (addr,phone)	X					
	B. Owner Name, Tax ID & Addr.	X					
	C. Product/Business & SIC Code	X	*				
II.	A. Plant/Site Name	X					
	B. Address of Facility	X					
	C. Nearest City, County and Zip	X	*				
	D. Latitude and Longitude	X					
	E. TNRCC Air Quality Acct. No.	N/A	*				This is a grass roots facility.
III.	A. Name of Facility	X					
	B. Facility Type	X					[X]PERMANENT [ ]PORTABLE
	C. Operating Schedule	X					
	D. Start Dates	X	*				CONST DATE 1-1-95 OPER DATE 1-1-97
IV.	A. New Permit Unit - grass roots	X					New grass roots facility at this location.
	B. New Permit Unit - non-permitted						Modification of exist. non-permitted facility.
	C. Amendment to permitted facility						[ ]Present Permit No.
	D. Change in Location						[ ]Present Permit No.
V.	A. Compliance History - Exempt						[ ]YES [X]NO
	B. Comp. Hist. - site => 5 yr old						[ ]YES [X]NO
	C. Comp. Hist. - new site	X					[X]YES [ ]NO
	D. Comp. Hist. - site < 5 yr old						[ ]YES [X]NO
VI.	A.1 Area Map	X					
	School within 3,000 feet?	X					[ ]YES [X]NO
	A.2 Plot Plan	X					
	B. Emission Data & Table 1(a)	X					
	C. BACT Analysis	X					
	D. Franchise Tax Certificate	N/A	*				[X]N/A [ ]Certificate good thru __/__/__
	E. Permit Fee Required?	X					[X]YES [ ]NO
	Fee Cert. & Table 30	N/A					The capital cost of the project will
VII.	A. Process Flow Diagram	X					exceed $15,000,000.
	B. Process Description	X					
	C. Material Balance	X					
VIII.	116.111(1) TNRCC Rules & Regs	X					
	116.111(2) Emissions Measurement	X					
	116.111(3) BACT Analysis	X					
	116.111(4) NSPS	X					
	116.111(5) NESHAPS	X					
	116.111(6) Facility Performance	X					
	116.111(7) Non-Attainment review	X					MAJOR SOURCE/MODIFICATION? [ ]YES [X]NO
	116.111(8) PSD review	X					MAJOR SOURCE/MODIFICATION? [X]YES [ ]NO
	116.111(9) Impacts/Modeling						will be submitted at a later date
X.	Copy to EPA Region 6 office	X	*				[X]YES [ ]N/A
	Copy to TNRCC Regional Office	X	*				[X]YES City - Arlington
	Copy to Local Program(s)	N/A	*				[ ]YES [X]N/A
XI.	Application "sealed" by P.E.?	X					[X]YES [ ]NO
XII.	Authorizing Signature/Date	X					

* *These items will not result in the application being considered administratively deficient; however, they MUST be submitted prior to final action or approval of the application.*

(1) *CONFIDENTIAL information MUST be clearly marked on each page and separated from non-confidential information. The application must include in the non-confidential files a topic outline describing the confidential information. To be considered confidential, each page must be marked "CONFIDENTIAL" at the time of submittal.*

Version 09/01/93

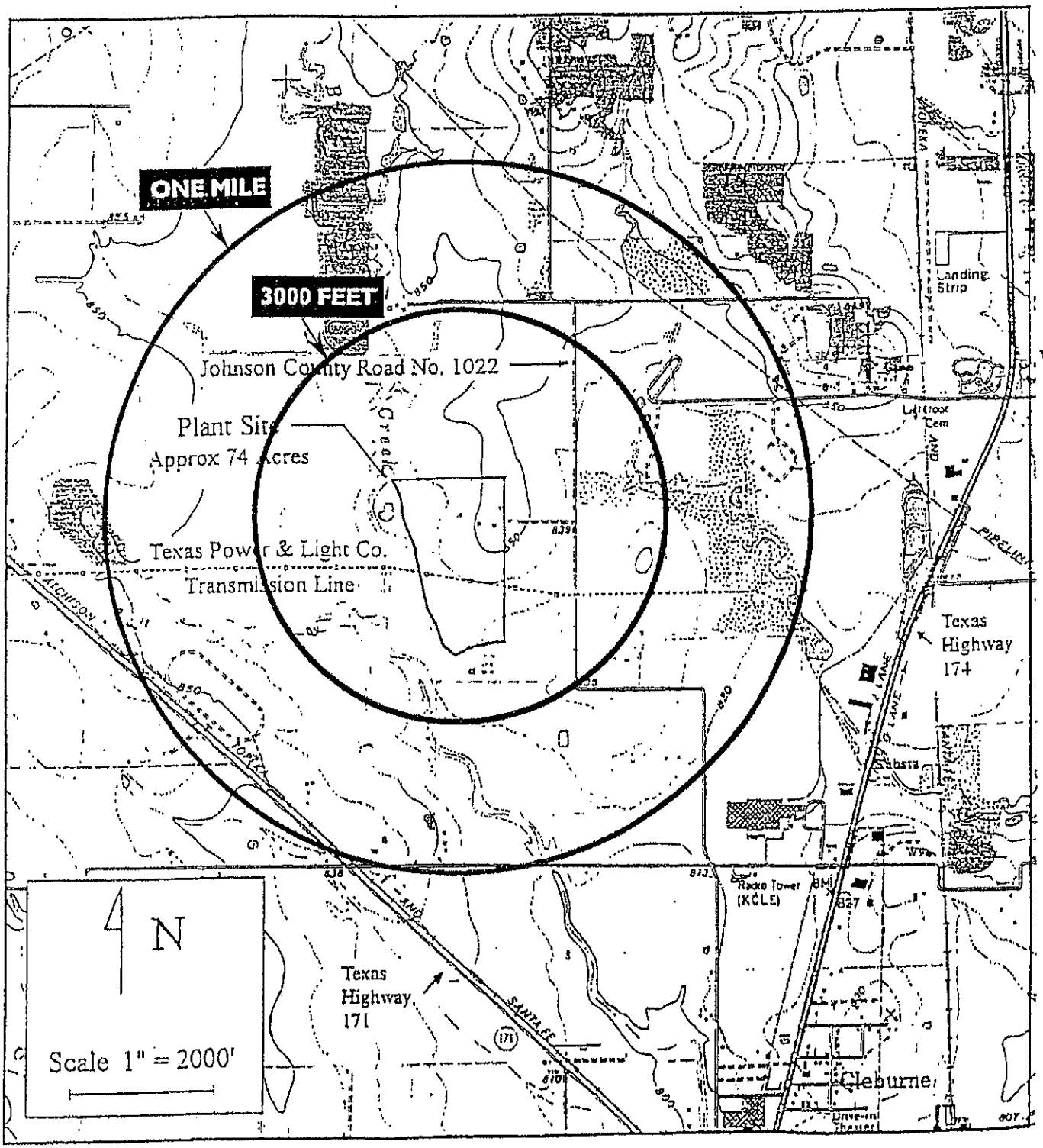
Espey, Huston & Associates, Inc.

ITEM VI.A

AREA MAP

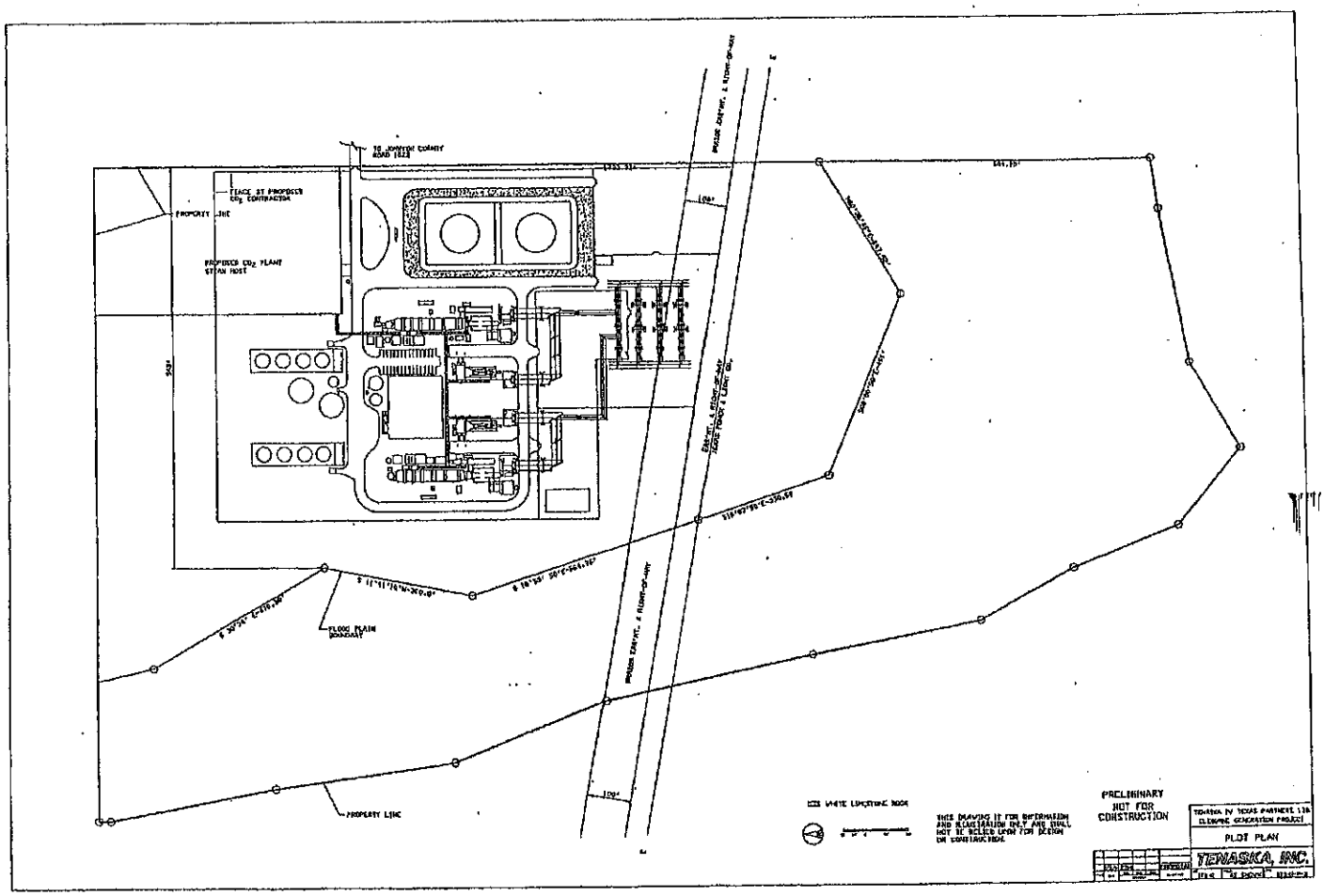
15495\940312

Tenaska Brazos Cogeneration Project
Cleburne, Johnson County, Texas
Plant Location



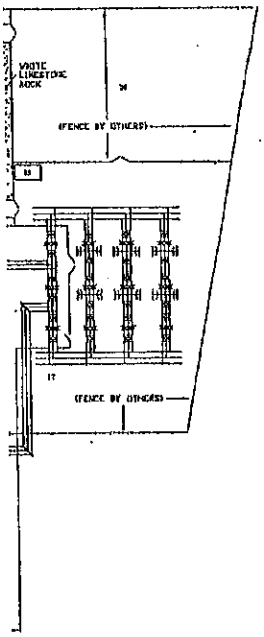
Bepp, Huston & Associates, Inc.

[illegible]
[illegible] PLAN


TO JOHNSON COUNTY ROAD 1023
FENCE AT PROPOSED CO_2 CONTRACTOR
PROPERTY LINE
PROPOSED CO_2 PLANT STEAM HOST
FLOOD PLAIN BOUNDARY
PROPERTY LINE
PRELIMINARY
NOT FOR CONSTRUCTION
PLOT PLAN
TENASKA, INC.

LEGEND

1. NATURAL GAS SCRUBBER
2. BOILER DRAIN SUMP
3. WATER METER HOUSE
4. COOLING TOWER WATER TREATMENT BUILDING
5. COOLING TOWER
6. CIRCULATING WATER PUMPS
7. STEAM TURBINE
8. LIQUID FUEL PACKAGE
9. PARKING
10. GENERATOR
11. DUCT BURNER MANAGEMENT SKID
12. BUILDING FOR: CONTROL & SWITCH GEAR, WATER TREATMENT, OFFICE, MAINTENANCE,
13. GENERATOR STEPUP TRANSFORMER
14. MECHANICAL AND ELECTRICAL CONTROL PACKAGES
15. BFW PUMPS
16. CONDENSATE RETURN TANK
17. BRAZOS SWITCHYARD
18. TENASKA SWITCHYARD
19. AIR INLET
20. ATOMIZING AIR SKID
21. STARTING MOTOR
22. COMBUSTION TURBINE
23. STORM WATER SETTLING POND
24. AMMONIA BLOWER
25. BARZOS RELAY BUILDING
26. CONDENSER TUBE REMOVAL
27. AMMONIA TANK
28. BLOWDOWN TANK
29. HEAT RECOVERY STEAM GENERATOR
30. EVAP COOLER SUMP
31. WATER PUMP HOUSE
32. CITY WATER TANK
33. NEUTRALIZATION TANK
34. DEMINERALIZED WATER STORAGE TANK
35. CONDENSATE PUMPS
36. ACID TANK
37. OIL-WATER SEPARATOR
38. CAUSTIC TANK
39. AUXILIARY COOLING WATER PUMPS
40. COOLING TOWER MAKEUP STORAGE TANK
41. CO2 FIRE PROTECTION SKID
42. EARTH BERM
43. OIL STORAGE TANK
44. FUEL OIL UNLOADING AND TRANSFER PUMPS
45. H.R.S.G. STACK
46. UNIT AUX. TRANSFORMER
47. NATURAL GAS CUSTODY FILTERS, REGULATION AND METER
48. WASTE WATER SUMP
49. DEAERATOR
50. FIRE HALL
51. PIPE RACK
52. CONTINUOUS EMISSION MONITOR BUILDING
53. NOT USED
54. BOILER CHEMICAL FEED BUILDING (ALSO NOT USED)
55. COMPRESSOR IN-LINE DRY-LINE WATER WASH SKID
56. BRAZOS DISTRIBUTION SUBSTATION
57. COKEN AUX BOILER
58. AUX BOILER FD FAN
59. FUEL GAS PREHEATER
60. KETTLE BOILER
61. VACUUM PUMP HOUSE



RELIMINARY
NOT FOR
NSTRUCTION

TENASKA IV TEXAS PARTNERS, LTD.
CLEBURNE GENERATION PROJECT

PLOT PLAN

TENASKA, INC.

179.41 | AS SHOWN | 179.41-M-10

Espey, Huston & Associates, Inc.

ITEM VI.C

TNRCC TABLE 1(a)s - EMISSIONS SOURCES

15495\940312

PERMIT NO.
ACCOUNT ID NO.

TABLE 1(a)
EMISSION SOURCES

PAGE 1 OF 4
DATE JUNE 1994

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

EMISSION POINT [1]		AIR CONTAMINANT DATA: CHEMICAL COMPOSITION OF TOTAL STREAM		AIR CONTAMINANT EMISSION RATE		EMISSION POINT DISCHARGE PARAMETERS: UTM COORDINATES OF EMISSION PT. [6]			STACK SOURCES [7]: HEIGHT ABOVE GROUND	HEIGHT ABOVE STRUCT.	EXIT DATA			AREA SOURCES [8]	
NUMBER	NAME	COMPONENT OR AIR CONTAMINANT NAME [2]	CONC. (%v) [3]	# / HR [4]	TONS/YR [5]	ZONE	EAST (meters)	NORTH (meters)	(ft)	(ft)	DIA. (ft)	VEL. (fps)	TEMP. (°F)	LENGTH (ft)	WIDTH (ft)
W-GT/HRSG	West GT/HRSG Stack	NO_x		117.1	278.2	14	649615	3595576	110		16.0	47.3	180		
		SO_2		94.9	80.1										
		CO		311.0	495.4										
		VOC		30.0	60.8										
		Particulate		88.9	78.77										
		PM_{10}		88.0	74.8										
		Ammonia		32.5	127.4										

GROUND ELEVATION OF FACILITY ABOVE MEAN SEA LEVEL – 840 FEET.
TACB STANDARD CONDITIONS ARE 68°F AND 14.7 PSIA [RULE 101.01.00.001(55)]
General Instructions:

1. Identify each emission point with a unique number for this plant site, consistent with emission point identification used on plot plan, previous permits and Emissions Inventory Questionaire. Limit emission point number to 6 character spaces. For each emission point use as many lines as necessary to list contaminant data. Typical emission point names are: heater, vent, boiler, tank, reactor, separator, baghouse, fugitive, etc. Abbreviations are OK.
2. Typical component names are: air, H_2O, nitrogen, oxygen, CO_2, NO_x, SO_2, hexane, particulate matter (PM), etc. Abbreviations are OK.
3. Concentration data is required for all gaseous components. Show concentration in volume percent of total gas stream.
4. Pounds per hour (#/HR) is maximum emission rate expected by applicant.
5. Tons per year (T/Y) is annual maximum emission rate expected by applicant, which takes into account process operating schedule.
6. As minimum applicant must furnish a facility plot plan drawn to scale showing a plant benchmark, latitude and longitude correct to the nearest second for the benchmark, and all emission points dimensioned with respect to the benchmark as required by General Application, Form PI-1. This information is essential for calculation of emission point UTM coordinates. Please show emission point UTM coordinates if known.
7. Supply additional information as follows if appropriate:
   (a) Stack exit configuration other than a round vertical stack. Show length and width for a rectangular stack. Indicate if horizontal discharge with a note.
   (b) Stack's height above supporting or adjacent structures if structure is within 3 "stack heights above ground" of stack.
   (c) If emission point is a flare, show flare data on Table 6.
8. Normally used for fugitive sources. Show dimensions of a minimum size rectangle which will "enclose" all fugitive sources included in this emission point number.

PERMIT NO.
ACCOUNT ID NO.

PAGE 2 OF 4
DATE JUNE 1994

TABLE 1(a)
EMISSION SOURCES

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS									
EMISSION POINT [1]		CHEMICAL COMPOSITION OF TOTAL STREAM		AIR CONTAMINANT EMISSION RATE		UTM COORDINATES OF EMISSION PT. [6]			STACK SOURCES [7]					AREA SOURCES [8]	
									HEIGHT ABOVE GROUND	HEIGHT ABOVE STRUCT.	EXIT DATA				
NUMBER	NAME	COMPONENT OR AIR CONTAMINANT NAME [2]	CONC. (%v) [3]	# / HR [4]	TONS/YR [5]	ZONE	EAST (meters)	NORTH (meters)	(ft)	(ft)	DIA. (ft)	VEL. (fps)	TEMP. (°F)	LENGTH (ft)	WIDTH (ft)
E-GT/HRSG	East GT/HRSG Stack	NO_x		117.1	276.2	14	649728	3565578	110		18.0	47.3	190		
		SO_2		94.9	80.1										
		CO		311.0	495.4										
		VOC		30.0	60.6										
		Particulate		66.9	78.77										
		PM_{10}		68.0	74.8										
		Ammonia		32.5	127.4										

GROUND ELEVATION OF FACILITY ABOVE MEAN SEA LEVEL ~ 840 FEET.
TACB STANDARD CONDITIONS ARE 68°F AND 14.7 PSIA [RULE 131.01.00.001(55)]
General Instructions:

1. Identify each emission point with a unique number for this plant site, consistent with emission point identification used on plot plan, previous permits and Emissions Inventory Questionaire. Limit emission point number to 8 character spaces. For each emission point use as many lines as necessary to list contaminant data. Typical emission point names are: heater, vent, boiler, tank, reactor, separator, baghouse, fugitive, etc. Abbreviations are OK.
2. Typical component names are: air, H_2O, nitrogen, oxygen, CO_2, NO_x, SO_2, hexane, particulate matter (PM), etc. Abbreviations are OK.
3. Concentration data is required for all gaseous components. Show concentration in volume percent of total gas stream.
4. Pounds per hour (#/HR) is maximum emission rate expected by applicant.
5. Tons per year (T/Y) is annual maximum emission rate expected by applicant, which takes into account process operating schedule.
6. As minimum applicant must furnish a facility plot plan drawn to scale showing a plant benchmark, latitude and longitude correct to the nearest second for the benchmark, and all emission points dimensioned with respect to the benchmark as required by General Application, Form PI-1. This information is essential for calculation of emission point UTM coordinates. Please show emission point UTM coordinates if known.
7. Supply additional information as follows if appropriate:
   (a) Stack exit configuration other than a round vertical stack. Show length and width for a rectangular stack. Indicate if horizontal discharge with a note.
   (b) Stack's height above supporting or adjacent structures if structure is within 3 "stack heights above ground" of stack.
   (c) If emission point is a flare, show flare data on Table 3.
8. Normally used for fugitive sources. Show dimensions of a minimum size rectangle which will "enclose" all fugitive sources included in this emission point number.

PERMIT NO.
ACCOUNT ID NO.

TABLE 1(a)
EMISSION SOURCES

PAGE 3 OF 4
DATE JUNE 1994

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA						EMISSION POINT DISCHARGE PARAMETERS									
EMISSION POINT [1]		CHEMICAL COMPOSITION OF TOTAL STREAM		AIR CONTAMINANT EMISSION RATE		UTM COORDINATES OF EMISSION PT. [6]			STACK SOURCES [7]					AREA SOURCES [8]	
									HEIGHT ABOVE GROUND (ft)	HEIGHT ABOVE STRUCT. (ft)	EXIT DATA				
NUMBER	NAME	COMPONENT OR AIR CONTAMINANT NAME [2]	CONC.(%v) [3]	# / HR [4]	TONS/YR [5]	ZONE	EAST (meters)	NORTH (meters)			DIA. (ft)	VEL. (fps)	TEMP. (°F)	LENGTH (ft)	WIDTH (ft)
AUXBOILER	Auxiliary Boiler Stack	NO_x		14.9	43.0	14	649726	3585561	110		3.50	76.4	320		
		SO_2		7.6	8.2										
		CO		28.1	122.7										
		VOC		1.5	4.3										
		Particulate		7.4	5.8										
		PM_{10}		7.1	5.7										

GROUND ELEVATION OF FACILITY ABOVE MEAN SEA LEVEL – 840 FEET.
TACB STANDARD CONDITIONS ARE 68°F AND 14.7 PSIA [RULE 101.01.00.001(55)]
General Instructions:

1. Identify each emission point with a unique number for this plant site, consistent with emission point identification used on plot plan, previous permits and Emissions Inventory Questionaire. Limit emission point number to 8 character spaces. For each emission point use as many lines as necessary to list contaminant data. Typical emission point names are: heater, vent, boiler, tank, reactor, separator, baghouse, fugitive, etc. Abbreviations are OK.
2. Typical component names are: air, H_2O, nitrogen, oxygen, CO_2, NO_x, SO_2, hexane, particulate matter (PM), etc. Abbreviations are OK.
3. Concentration data is required for all gaseous components. Show concentration in volume percent of total gas stream.
4. Pounds per hour (#/HR) is maximum emission rate expected by applicant.
5. Tons per year (T/Y) is annual maximum emission rate expected by applicant, which takes into account process operating schedule.
6. As minimum applicant must furnish a facility plot plan drawn to scale showing a plant benchmark, latitude and longitude correct to the nearest second for the benchmark, and all emission points dimensioned with respect to the benchmark as required by General Application, Form PI-1. This information is essential for calculation of emission point UTM coordinates. Please show emission point UTM coordinates if known.
7. Supply additional information as follows if appropriate:
   (a) Stack exit configuration other than a round vertical stack. Show length and width for a rectangular stack. Indicate if horizontal discharge with a note.
   (b) Stack's height above supporting or adjacent structures if structure is within 5 "stack heights above ground" of stack.
   (c) If emission point is a flare, show flare data on Table 6.
8. Normally used for fugitive sources. Show dimensions of a minimum size rectangle which will "enclose" all fugitive sources included in this emission point number.

PERMIT NO.
ACCOUNT ID NO.

TABLE 1(a)
EMISSION SOURCES

DATE JUNE 1994

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

EMISSION POINT [1]		AIR CONTAMINANT DATA: CHEMICAL COMPOSITION OF TOTAL STREAM		AIR CONTAMINANT EMISSION RATE		UTM COORDINATES OF EMISSION PT. [6]			EMISSION POINT DISCHARGE PARAMETERS: STACK SOURCES [7]					AREA SOURCES [8]	
		COMPONENT OR AIR CONTAMINANT NAME [2]	CONC. (%v) [3]	# / HR [4]	TONS/YR [5]	ZONE	EAST (meters)	NORTH (meters)	HEIGHT ABOVE GROUND (ft)	HEIGHT ABOVE STRUCT. (ft)	EXIT DATA: DIA (ft)	VEL. (fps)	TEMP. (°F)	LENGTH (ft)	WIDTH (ft)
NUMBER	NAME														
FP-1	Fire Pump*	PM		0.13	0.0012	14									
		SO_x		0.12	0.0011										
		CO		0.41	0.0035										
		NO_x		1.87	0.016										
		VOC		0.15	0.0013										
H2SO4-TK	Sulfuric Acid Tank	Sulfuric Acid		0.0033	1.5×10^{-5}	14	649656	3585570							
CAUSTIC-TK	Caustic Tank	NaOH		nil	nil	14	649649	3585579							
OIL-TK1	Fuel Oil Tank	Fuel Oil		0.62	0.29	14	649792	3585523							
OIL-TK2	Fuel Oil Tank	Fuel Oil		0.62	0.29	14	649792	3585467							
FUG-OIL	Fugitive Emissions	Fuel Oil		0.88	3.85	14									

GROUND ELEVATION OF FACILITY ABOVE MEAN SEA LEVEL – 640 FEET.
TACB STANDARD CONDITIONS ARE 68°F AND 14.7 PSIA [RULE 131.01.09.001(55)]

* Emissions are from one 20-minute test every week for maintenance.

General Instructions:

1. Identify each emission point with a unique number for this plant site, consistent with emission point identification used on plot plan, previous permits and Emissions Inventory Questionaire. Limit emission point number to 8 character spaces. For each emission point use as many lines as necessary to list contaminant data. Typical emission point names are: heater, vent, boiler, tank, reactor, separator, baghouse, fugitive, etc. Abbreviations are OK.
2. Typical component names are: air, H_2O, nitrogen, oxygen, CO_2, NO_x, SO_x, hexane, particulate matter (PM), etc. Abbreviations are OK.
3. Concentration data is required for all gaseous components. Show concentration in volume percent of total gas stream.
4. Pounds per hour (#/HR) is maximum emission rate expected by applicant.
5. Tons per year (T/Y) is annual maximum emission rate expected by applicant, which takes into account process operating schedule.
6. As minimum applicant must furnish a facility plot plan drawn to scale showing a plant benchmark, latitude and longitude correct to the nearest second for the benchmark, and all emission points dimensioned with respect to the benchmark as required by General Application, Form PI-1. This information is essential for calculation of emission point UTM coordinates. Please show emission point UTM coordinates if known.
7. Supply additional information as follows if appropriate:
   (a) Stack exit configuration other than a round vertical stack. Show length and width for a rectangular stack. Indicate if horizontal discharge with a note.
   (b) Stack's height above supporting or adjacent structures if structure is within 3 "stack heights above ground" of stack.
   (c) If emission point is a flare, show flare data on Table 6.
8. Normally used for fugitive sources. Show dimensions of a minimum size rectangle which will "enclose" all fugitive sources included in this emission point number.

Espey, Huston & Associates, Inc.

ITEM VI.D

BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

ITEM VI.D
BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

1.0 INTRODUCTION

The TNRCC regulations require new stationary sources to apply the BACT in the control of each air contaminant that may be emitted from the project. In addition, the PSD regulations require that BACT be applied to each regulated air contaminant that may be emitted in significant amounts from a major stationary source or a modification to a major source as defined by the PSD rules. As shown in Table 1a, Item VI.C of this application, the project will result in PSD significant emissions of carbon monoxide (CO), particulate matter (PM), particulate matter less than 10 microns in diameter (PM_{10}), nitrogen oxides (NO_x), sulfur dioxide (SO_2), and volatile organic compounds (VOC). In addition, the project will also be a source of ammonia emissions due to the type of controls proposed to control NO_x emissions. Therefore, a BACT analysis is required for these air contaminants. Details of this project are provided in Item VII.B of this application. This section presents a demonstration that BACT will be utilized to control emissions from the project.

2.0 BACT APPROACH

The requirement for the use of BACT is intended to ensure that a proposed facility will incorporate control systems that reflect the latest techniques used in a particular industry, allow for future growth in the vicinity of the proposed facility, and do not result in an exceedance of National Ambient Air Quality Standards. The TNRCC guidance on the approach to BACT is a three tiered approach to the determination of what is BACT. The first tier reflects the type of control which has been determined to be BACT for a similar air contaminant source. The second tier is the control which has been determined to be BACT for a different type of source but which is similar in operation and has similar air contaminant emissions. If a BACT determination cannot be arrived at from the first two tiers, then the Agency relies on a rigorous technical and economic evaluation of alternative air pollution controls, taking into account energy, environmental and

economic impacts. This third tier requires the documentation of performance levels and technical limitations of each air pollution control technology evaluated. Associated material, energy, and economic penalties associated with the alternative controls, as well as the environmental benefits derived from these systems are also evaluated. The first tiered approach has been used in this evaluation to demonstrate compliance with the BACT requirements of the TNRCC.

Information with regard to previous BACT determinations for a project of this type and size was gathered from several different sources. These sources included a review of the BACT/LAER Clearinghouse, the EPA's electronic bulletin board, discussions with the TNRCC air quality staff with regard to previous PSD determinations, and information from equipment manufacturers. Included in Appendix A are copies of excerpts from the BACT/LAER Clearinghouse and information obtained from the EPA bulletin board which were pertinent to this evaluation. A listing from the TNRCC of NO_x limitations incorporated in permits issued for gas turbine facilities rated at 20 MWe or greater of electrical output is also included. Appendix F includes guarantees of performance from equipment manufacturer's. These sources of information formed the basis for the following BACT evaluation.

3.0 CONTROL OF NITROGEN OXIDE EMISSIONS

The formation of nitrogen oxides occurs from the combustion process in two ways. One is through the combination of elemental nitrogen and oxygen in the combustion air within the high temperature environment of the combustor. NO_x formed in this way is referred to as "thermal NO_x". The other way NO_x is formed is through the oxidation of nitrogen contained in the fuel, referred to as "fuel NO_x". Neither the natural gas or fuel oil (diesel) proposed for the gas turbine/HRSGs and the auxiliary boiler contains a significant amount of nitrogen. Therefore, the bulk of the NO_x emissions will originate as thermal NO_x.

The rate of formation of thermal NO_x is a function of the residence time, free oxygen, and peak flame temperature. Therefore, some NO_x control techniques are aimed at minimizing one or more of these variables to reduce NO_x. Other control methods, known as "tail gas" or "back-end" techniques remove NO_x from the exhaust gas stream after NO_x has been formed.

3.1 CONTROL OF NO_x EMISSIONS FROM THE GAS TURBINE/HRSG UNITS

Based on a review of previous BACT determinations and on discussions with the TNRCC, the most stringent method for the control of NO_x emissions from a gas turbine/HRSG system is a combination of steam injection in the turbines and the use of Selective Catalytic Reduction (SCR) at the back-end of the system.

In the SCR process, ammonia injected into the gas turbine exhaust gas reacts with NO_x and oxygen in the exhaust gas to form nitrogen and water. The chemical reactions

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

and

$$6\ NO_2 + 8\ NH_3 \rightarrow 7\ N_2 + 12\ H_2O$$

take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_x decomposition reaction. The optimum operating temperature for most SCR systems has been shown to be in the range of 500 to 850° F.

In the catalyst bed, blocks of catalyst elements are assembled together to fill the full cross-section of the HRSG. The blocks are oriented perpendicular to the turbine exhaust gas flow such that the entire exhaust gas stream flows uniformly through the catalyst unit. The catalyst will be installed between the tube bundles within the HRSG so that exhaust gas passing through the catalyst is in the catalyst's most active temperature range.

Catalyst systems will promote the oxidation of sulfur dioxide to sulfur trioxide (SO_3), which combines with water to form sulfuric acid. The proposed cogeneration project will burn low sulfur fuels which will minimize sulfuric acid formation. Excess ammonia injected into the exhaust gas will largely neutralize the acid to form ammonium sulfate which is assumed to be emitted as particulate matter. Therefore, sulfuric acid formation should not be of concern.

The SCR system will be designed for a nominal 80% reduction of flue gas NO_x emissions when firing natural gas and a nominal 77% reduction when firing fuel oil. No more than 10 ppm of unreacted ammonia will remain in the flue gas.

To assist in achieving these low NO_x emission rates from the gas turbine/HRSG, a staged approach will be utilized whereby the initial NO_x removal will be achieved by the injection of steam into the turbine. When natural gas is fired, NO_x emissions from the gas turbines will be controlled to 42 ppmvd (corrected to 15% oxygen (O_2)) by steam injection into the turbine combustors. When fuel oil is fired gas turbine NO_x emissions will be controlled to 65 ppmvd (corrected to 15% O_2) by steam injection into the turbine combustors.

Low emissions combustion systems will also be used in the HRSG duct burners to minimize NO_x emissions. The proposed NO_x control technique for the duct burners is modern burner design, such that NO_x emission rates will not exceed 0.08 lb NO_x/MMBtu heat input (HHV). The duct burners will be fired with only natural gas.

As discussed above, the NO_x concentration in the gas turbine/HRSG exhaust will be further reduced by the use of a selective catalytic reduction (SCR) system which will be installed in the HRSG downstream of the duct burner. The final NO_x concentration at the HRSG exhaust stack will be controlled to 9 ppmvd (corrected to 15% O_2) when firing natural gas and 15 ppmvd (corrected to 15% O_2) when firing fuel oil (see equipment manufacturer's guarantees in Appendix F). The implementation of these combined technologies is designed to perform in accordance with, or better than, Environmental Protection Agency (EPA) and TNRCC guidelines for BACT for large gas turbine/HRSG systems.

3.2 CONTROL OF NO_x EMISSIONS FROM THE AUXILIARY BOILER

As with the gas turbine/HRSG systems, emissions of NO_x from the auxiliary boiler will be primarily thermal NO_x as only natural gas or fuel oil will be fired. In addition, the boiler will only be used as a backup source of steam for the adjacent industrial facility should the gas turbine/HRSG go down and will therefore not be operated on a year-round basis.

3.2.1 Selective Catalytic Reduction Technology

The use of SCR can also be considered the most stringent NO_x control technique applicable to the auxiliary boilers. However, it is not generally applied a boiler in the capacity range as that of the boiler proposed for this project. This is due to the significant capital and operating expenses involved and the relatively low potential for emissions reduction for small capacity boilers.

3.2.2 Selective Non-Catalytic Reduction Technology

The second most stringent NO_x control technique is selective non-catalytic reduction (SNCR). SNCR involves the non-catalytic decomposition of NO_x in the flue gas to nitrogen and water using ammonia as a reducing agent. This control technology is based on a gas phase reaction between the reducing agent and NO_x within a specific temperature range (1600 to 2200° F). Achieving the required reaction temperature range within the boiler flue gas represents the primary problem with utilization of this technology. The necessary temperature range is found in different areas of a boiler depending on its design and operating load. Size constraints imposed in a particular application are also a significant design factor. Size constraints are primarily related to the size of the combustion chamber and the difficulty of locating the injection nozzles to provide the necessary time/temperature relationships required of this technology. Because of these problems, the use of SNCR is also not considered representative of BACT for the proposed auxiliary boiler.

3.2.3 Combination Low-NO_x Burner/Flue Gas Recirculation Technology

Tenaska proposes to achieve the necessary NO_x control in the auxiliary boiler through the use of low-NO_x burners in combination with flue gas recirculation. The low-NO_x burner is designed to split the combustion flame into two zones thereby decreasing NO_x formation. As the boiler will be fired with primarily natural gas with fuel oil backup, a combination staged air and/or staged fuel burner will be utilized. The staged air burner is designed to split the combustion flame by diverting a portion of the combustion air downstream of the primary fuel injection point when

burning natural gas. The staged fuel burner splits the combustion flame by dividing the fuel flow into two zones when firing fuel oil.

The formation of NO_x is suppressed in the staged air burner by the promotion of a fuel-rich primary combustion zone, followed by complete combustion in the secondary combustion zone. The lack of excess air in the primary zone limits NO_x formation. Incomplete combustion products formed in this primary zone act as reducing agents in the secondary combustion zone. The staged fuel burner combustion approach works by lowering the peak flame temperature in the fuel-lean primary zone. Complete combustion is then accomplished in the secondary zone. Combustion products from the primary zone act to lower the local oxygen concentration in the secondary, thereby suppressing NO_x formation in this zone as well.

Flue gas recirculation involves recycling a portion of the auxiliary boiler flue gas and returning it to the boiler through the burner or windbox. The primary effect of this technique is a reduction of the peak flame temperature in the burner through absorption of the combustion heat by the relatively inert flue gas. In addition, the flue gas reduces the oxygen concentration in the combustion air, effecting a reduction in thermal NO_x formation by decreasing oxygen availability.

The effectiveness of this control method depends on the fuel being fired. Since flue gas recirculation reduces NO_x formation by targeting peak flame temperature, it has little effect on fuel NO_x formation, thus it is less effective on fuels with a high nitrogen content. In addition, the NO_x reduction efficiency is directly related to the flue gas recirculation rate. Typically an increase in the recirculation rate results in a corresponding decrease in thermally generated NO_x. Beyond 20% recirculation, however, the effectiveness begins to diminish as flame stability becomes a problem.

Utilizing the combination of low-NO_x burner/flue gas recirculation technique, the NO_x emissions from the auxiliary boiler will be reduced to a maximum of 0.06 lb NO_x/MMBtu when burning natural gas and to a maximum of 0.1 lb NO_x/MMBtu when burning fuel oil (see equipment manufacturer guarantees in Appendix F). As the boiler will be operated only as a backup to the gas turbine/HRSG system, the implementation of these combined technologies is designed to

perform in accordance with, or better than, EPA and TNRCC guidelines for BACT for auxiliary boilers of this type.

3.3 ALTERNATIVE NO_x CONTROL TECHNOLOGIES

Tenaska has reviewed the available applicable control alternatives which have been used to control NO_x emissions. The review indicates that the proposed technologies have been successful in reducing NO_x emissions. In addition to the potential for lower NO_x emissions, the proposed technologies will offer several major operating and economic benefits as they are simple, stable processes with high reliability and low maintenance requirements.

4.0 CONTROL OF CARBON MONOXIDE EMISSIONS

Carbon monoxide is formed as a result of the incomplete combustion of fuel and is a function of oxygen availability, flame temperature, residence time at flame temperature, combustion zone design and turbulence. Control of CO is thus accomplished by providing adequate fuel residence time and sufficiently high temperature in the combustion device to ensure complete combustion. These control factors, however, could result in high emissions rates of NO_x. Conversely, a low NO_x emissions rate achieved through flame temperature control; i.e., by steam injection, can result in higher levels of CO emissions. Thus, a compromise is established whereby the flame temperature reduction is set to achieve the lowest NO_x emissions rate possible while keeping the CO emission rates at acceptable levels.

4.1 CONTROL OF CO EMISSIONS FROM THE GAS TURBINE/HRSG SYSTEMS

4.1.1 Catalytic Oxidation Technology

The most stringent method of CO control for the gas turbine/HRSG may be achieved through the use of a catalytic oxidation reactor which oxidizes the CO in the gas stream to CO_2. As with the SCR technology, catalytic oxidation reactor systems are utilized to remove pollutants at the back-end of the gas turbine/HRSG system rather than limiting pollutant formation at the front-end. CO catalytic oxidation technology does not require the introduction of additional

chemicals for the reaction to proceed. The oxidation reaction uses excess air or oxygen in the gas turbine exhaust in the presence of the catalyst; the catalyst serving to reduce the activation energy required for the reaction.

As with the SCR technology, CO catalytic oxidation reactors are required to operate within a relatively narrow temperature range. Optimum operating temperatures for these systems generally fall into the range of 700 to 1100° F. At lower temperatures, CO conversion efficiency falls off rapidly. Above 1200° F, catalyst sintering may occur, thus causing permanent damage to the catalyst. Maintaining operation within this required temperature range is a concern. In addition, pressure losses across an oxidation catalyst reactor result in a loss in power output and fuel efficiency. Because of these problems, the use of the CO catalytic oxidation is not considered representative of BACT for the proposed gas turbine/HRSG systems.

4.1.2 Combustion Controls

Tenaska proposes to achieve the necessary CO control through the use of proper combustion control. By operating the gas turbine/HRSG systems properly to insure good combustion, Tenaska will keep CO emissions from the gas turbines to a minimum. In addition, the duct burners will be designed such that they will achieve a maximum of 0.10 lb CO per MMBtu (HHV) when burning either natural gas or fuel oil. This control method is proven reliable, does not carry additional economic impact, and does not result in increased emissions for other pollutants. These levels of control are consistent with what has been established to be BACT for the control of CO from gas turbines and duct burners by the EPA and the TNRCC. Therefore, the use of proper design and operation of the gas turbines and duct burners is BACT for the control of CO emissions from the gas turbine/HRSG systems.

4.2 CONTROL OF CO EMISSIONS FROM THE AUXILIARY BOILER

As with the gas turbine/HRSG units, emissions of CO are derived from the incomplete combustion of the natural gas or fuel fired. The boiler will be properly designed so as to minimize formation or remove CO from the exhaust gas. In addition, the boiler will only be operated as a

backup source of steam for the adjacent industrial facility and will not be operated continuously on a year-round basis.

4.2.1 Catalytic Oxidation Technology

Catalytic oxidation technology can be considered the most stringent CO control technique applicable to the auxiliary boilers. However, it is not generally applied to a boiler in the capacity range proposed for this project. Boilers in the size range proposed for this project firing natural gas or fuel typically do not generate large quantities of CO emissions, thus, the cost effectiveness of this alternative is typically poor considering the relatively low potential for emissions reduction. Therefore, catalytic oxidation is not considered representative of BACT for the auxiliary boiler.

4.2.2 Combustion Controls

The auxiliary boiler will be equipped with high efficiency burners which will limit the formation of CO by providing for high efficiency combustion of fuels. The auxiliary boiler burners will be designed such that they will achieve a maximum of 0.18 lb CO/MMBtu when burning either natural gas or fuel oil (see equipment manufacturer's guarantee in Appendix F). As the boiler will not be operated on a continuous basis, the use of proper burner design and combustion control is BACT for the control for CO emissions from the auxiliary boiler.

5.0 CONTROL OF VOLATILE ORGANIC COMPOUND EMISSIONS

Volatile organic compounds are emitted from the gas turbine/HRSG systems and the auxiliary boiler as a result of incomplete combustion of fuel. Control of VOC emissions is primarily accomplished by providing adequate fuel residence time and sufficiently high temperature in the combustion device to ensure complete combustion.

5.1 CONTROL OF VOC EMISSIONS FROM THE GAS TURBINE/HRSG SYSTEMS

5.1.1 Catalytic Oxidation Technology

As with the control of CO emissions, VOC control for the gas turbine/HRSG may be achieved through the use of a catalytic oxidation reactor which oxidizes the unburned hydrocarbons in the gas stream to CO_2. The VOC catalytic oxidation reactors are utilized at the back-end of the gas turbine/HRSG system rather than limiting pollutant formation at the front-end. VOC catalytic oxidation technology does not require the introduction of additional chemicals for the reaction to proceed. The oxidation of unburned hydrocarbons to CO_2 uses the excess air or oxygen in the gas turbine exhaust for oxidation in the presence of the catalyst.

VOC catalytic oxidation reactors are required to operate within a relatively narrow temperature range. At temperatures below 1000° F, very little VOC is expected to oxidize. Above 1200° F, catalyst sintering may occur, thus causing permanent damage to the catalyst. Maintaining operation within this required temperature range is a concern. In addition, pressure losses across an oxidation catalyst reactor result in a loss in power output and fuel efficiency. Because of these problems, the use of the VOC catalytic oxidation is not considered representative of BACT for the proposed gas turbine/HRSG systems.

5.1.2 Combustion Controls

Tenaska proposes to achieve VOC control through the use of proper combustion control. By operating the gas turbine/HRSG systems properly to insure good combustion, Tenaska will keep VOC emissions from the gas turbine/HRSG units to a minimum. This control method is proven reliable, does not carry additional economic impact, and does not result in increased emissions for other pollutants. Therefore, the use of proper design and operation of the gas turbines and duct burners is BACT for the control of VOC emissions from the gas turbine/HRSG systems.

5.2 CONTROL OF VOC EMISSIONS FROM THE AUXILIARY BOILER

As with the gas turbine/HRSG units, emissions of VOC are derived from the incomplete combustion of the natural gas or fuel fired. The boiler will be properly designed so as to minimize formation or remove VOC from the exhaust gas. In addition, the boiler will only be operated as a backup source of steam for the adjacent industrial facility and will not be operated continuously on a year-round basis.

5.2.1 Catalytic Oxidation Technology

Catalytic oxidation technology can be considered as a technique applicable to the auxiliary boilers. However, it is not generally applied to a boiler in the capacity range proposed for this project. Boilers in the size range proposed for this project firing natural gas or fuel typically do not generate large quantities of VOC emissions, thus, the cost effectiveness of this alternative is typically poor considering the relatively low potential for emissions reduction. Therefore, catalytic oxidation is not considered representative of BACT for the auxiliary boiler.

5.2.2 Combustion Control

As discussed above, the auxiliary boiler will be equipped with high efficiency burners which will limit the formation of VOC by providing for high efficiency combustion of fuels. The auxiliary boiler burners will be designed such that they will achieve a maximum of 0.006 lb VOC/MMBtu when burning natural gas and 0.01 lb VOC/MMBtu when firing fuel oil (see equipment manufacturer's guarantee in Appendix F). As the boiler will not be operated on a continuous basis, the use of proper burner design and combustion control is BACT for the control for VOC emissions from the auxiliary boiler.

6.0 CONTROL OF PM/PM_{10} EMISSIONS

Particulate emissions from the project will consist of ash from the fuel, particulate of carbon and hydrocarbons resulting from incomplete combustion, and ammonium salts formed in the reaction of SO_3 and ammonia. As the units are designed to fire fuels with low ash contents

and high combustion efficiency, they will have correspondingly low particulate matter emission rates.

6.1 CONTROL OF PM/PM_{10} EMISSIONS FROM THE GAS TURBINE/HRSG UNITS

Typical particulate control devices such as electrostatic precipitators (ESPs) and baghouse filters are not suitable for use with gas turbines/HRSG units due to both the extremely low particulate emission concentration as well as the physical characteristics of the particles emitted. For ESPs which operate on the principal of charge migration, the low particulate concentration would prevent significant charge buildup on particles and thus, low migration of particles to collecting plates. In addition, the particulate matter resulting from oil or natural gas firing is typically hygroscopic, thus not suitable for a baghouse filter as it would tend to adhere to the bags and not be easily dislodged as required for periodic cleaning of the bags. Therefore, the use of ESPs or baghouse filters is considered technically infeasible and thus, not representative of BACT.

Tenaska proposes to use proper combustion techniques to ensure that the PM/PM_{10} emissions from the gas turbine/HRSG units will be minimized. PM/PM_{10} emissions resulting from ammonium sulfate formation will be minimized by utilizing low sulfur fuels and minimizing excess ammonia injected into the exhaust gas. In addition, burning of the fuel oil will be limited to only 720 hours per year. The use of proper combustion control and low sulfur, low ash fuels is representative of BACT for this project as these controls have been determined to be BACT in controlling PM/PM_{10} emissions from gas turbines and duct burners by the EPA and the TNRCC in previously issued permits.

6.2 CONTROL OF PM/PM_{10} EMISSIONS FROM THE AUXILIARY BOILER

As with the control of particulate matter emissions from the gas turbine/HRSG systems, traditional particulate matter control devices are not generally used on boilers of the size and firing the type of fuels proposed for this project.

Tenaska proposes to use proper combustion techniques to ensure that the PM/PM_{10} emissions from the auxiliary boiler will be minimized. The use of proper combustion control and low ash fuels has been determined to be BACT in controlling PM/PM_{10} emissions from boilers by the EPA and the TNRCC in previously issued permits. In addition, burning of the fuel oil will be limited to only 720 hours per year. Therefore, combustion control is BACT for the control of PM/PM_{10} emissions from the auxiliary boiler.

7.0 CONTROL OF SO_2 EMISSIONS

Sulfur dioxide is exclusively formed through the oxidation of the sulfur present in the fuel. The emission rate of SO_2 is a function of the combustion efficiency of the source and the sulfur content of the fuel, since virtually all fuel sulfur is converted to SO_2.

7.1 CONTROL OF SO_2 EMISSIONS FROM THE GAS TURBINE/HRSG SYSTEMS

The gas turbines will primarily use natural gas and will use low sulfur fuel oil (less than 0.05 %wt) only as a backup fuel. The use of the fuel oil will be limited to 720 hours per year. The duct burners will only be fired with natural gas. The use of low sulfur content gaseous and diesel fuels has been determined to be BACT in controlling SO_2 emissions by the TNRCC and the EPA in previously issued permits. Therefore, the use of low sulfur fuels is BACT for the control of SO_2 emissions from the gas turbine/HRSG systems.

7.2 CONTROL OF SO_2 EMISSIONS FROM THE AUXILIARY BOILER

The auxiliary boiler will also be designed with dual fuel capability. Although the boiler will be fired primarily with natural gas, it may be fired with low sulfur (0.05 %wt) fuel oil up to 720 hours per year. The use of low sulfur content gaseous and diesel fuels has been determined to be BACT in controlling SO_2 emissions by the TNRCC and the EPA in previously issued permits. Therefore, the use of low sulfur fuels is BACT for the control of SO_2 emissions from the auxiliary boiler.

8.0 CONTROL OF DIESEL STORAGE TANK EMISSIONS

The two 35,000-barrel diesel fuel storage tanks will be used to store diesel fuel having a very low vapor pressure. Emissions from these tanks will be minimized by the use of fixed-roof tanks. Because of the low vapor pressure of the fuel and the expected low rate of emissions, the use of fixed-roof tanks is BACT for these facilities and no additional controls are necessary.

9.0 CONTROL OF ANHYDROUS AMMONIA STORAGE TANK EMISSIONS

Anhydrous ammonia will be stored in a 12,000 gallon pressure vessel. As a result, there will be no emissions from this tank. The use of a pressure vessel is BACT for this facility and no additional controls are necessary.

10.0 CONTROL OF SULFURIC ACID STORAGE TANK EMISSIONS

Emissions from the 6,000 gallon sulfuric acid storage tank will be minimized by the use of a horizontal tank which operates at atmospheric pressure. Because the sulfuric acid will have a very low vapor pressure, emissions from this tank will be very low. Therefore, the use of a fixed-roof tank is BACT for this facility and no additional controls are necessary.

11.0 CAUSTIC STORAGE TANK

The 6,000 gallon caustic storage tank will be a horizontal storage tank which will contain a 50% wt sodium hydroxide solution. Because this solution will have a very low vapor pressure, emissions from this tank are estimated to be negligible. Because of the low emission rates, no additional control is BACT for this tank.

12.0 EMERGENCY FIRE PUMP ENGINES

Tenaska will utilize one 200-hp diesel-fired engine in case of fire. It is expected that this engine will be used only in emergencies, but it will also be operated for testing purposes a maximum of 20 minutes once per week. In addition, the sulfur content of the fuel oil will be very

low. Because of the limited hours of operation, no additional control beyond the proper operation of these engines is BACT for these facilities.

13.0 CONCLUSION

Based on the factors discussed above, Tenaska believes it has demonstrated BACT for controlling emissions from the proposed cogeneration project.

Kepay, Huston & Associates, Inc.

ITEM VI.E
FRANCHISE TAX STATEMENT

[illegible]

EH&A
Espey, Huston & Associates, Inc.

ITEM VI.E
FRANCHISE TAX STATEMENT

As Tonaska IV Texas Partners, Ltd. is a limited partnership, it is not required to pay a corporate franchise tax to the State of Texas. However, once a Certificate of Existence is received from the Secretary of State's office, Tonaska will provide a copy to the TNRCC.

EH&A
Espey, Huston & Associates, Inc.

ITEM VI.F
PERMIT FEE STATEMENT

15455040313

Espey, Huston & Associates, Inc.

ITEM VI.F

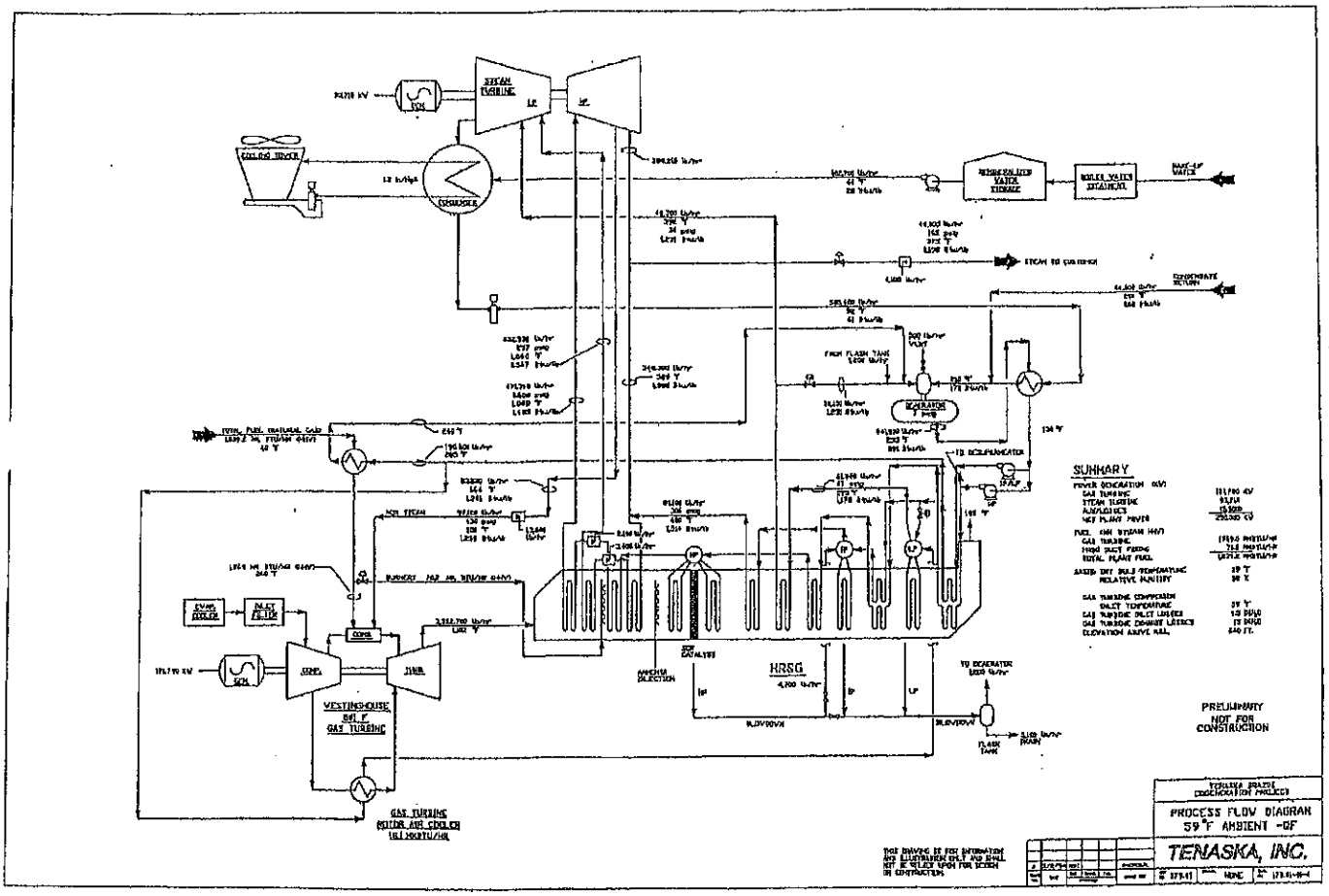
PERMIT FEE STATEMENT

The project will require a TNRCC air quality permit and a Prevention of Significant Deterioration permit. The capital cost of the project will exceed $15 million. Therefore, a check for $75,000, the maximum permit fee required under 31 TAC 116.163 has been remitted with this application.

EH&A
Espey, Huston & Associates, Inc.

ITEM VII.A
PROCESS FLOW DIAGRAM

15495/040312


STEAM TURBINE
COOLING TOWER
CONDENSER
BOILER WATER DEAERATOR
STEAM TO CUSTOMER
CONDENSATE RETURN
FROM FLASH TANK
DEAERATOR
TO DESUPERHEATER
SUMMARY
HRSG
WESTINGHOUSE
GAS TURBINE
GAS TURBINE
MOTOR AND COOLER
PRELIMINARY
NOT FOR
CONSTRUCTION
PROCESS FLOW DIAGRAM
59°F AMBIENT -GF
TENASKA, INC.

Espey, Huston & Associates, Inc.

ITEM VII.B
PROCESS DESCRIPTION

ITEM VII.B
PROCESS DESCRIPTION

The project will consist of two Westinghouse 501F gas turbine electric generating units each of which exhausts into it associated duct burner-fired heat recovery steam generator unit (HRSG) which will be used to generate steam and electricity. Two steam turbines with a nominal combined output of 208 MWe will be constructed to use steam produced in the HRSG. The project will have a combined electric generation nominal plant output of 500 MWe with over 95% of its electric power production being sold to an electric utility company. Each gas turbine/HRSG/steam turbine unit will be fully dispatchable from approximately 80 MWe to 250 MWe by automatic generation control at a loading/unloading rate which will be at least 5% per minute. The cogeneration project will be designed to operate at a maximum of 8,760 hours per year. The steam produced will be sold to an adjacent industrial facility. To serve as a backup source of steam for the adjacent industrial facility, an auxiliary boiler with a maximum fuel input of about 156 MMBtu/hr will be constructed.

A detail of project milestones is shown in Table VII.B-1. The desired permit issuance date of November 1994 is necessary for the project to complete financing by January 1995. The following subsections briefly describe key plant components. These components are shown on the Plot Plan and Plot Plan Detail in Item VI.B of this application. TNRCC Equipment Tables for the various equipment may be found in Appendix B.

1.0 GAS TURBINE UNITS

The cogeneration project will include two Westinghouse 501F gas turbine packages each capable of generating 172 MWe (nominal) of electrical output. In the gas turbine, air will be drawn in, compressed and forced into the turbine where it will be mixed with natural gas or fuel oil for combustion. Natural gas will be the primary fuel for the gas turbines with fuel oil (diesel) used as backup fuel. The fuel oil will be limited to a sulfur content of 0.05%wt or less. Steam will be injected into the turbine combustors to reduce the NO_x emissions. The steam injection rate will

TABLE VII.B-1

MILESTONE SCHEDULE

Sign Power Sales Agreement	November 1993
File Environmental Permit Applications	June 1994
EPC Contractor Selection	August 1994
Environmental Permits Issued	November 1994
Financial Closing	January 1995
Release Major Equipment Manufacturing	January 1995
EPC Contract On-Site Mobilization	June 1995
Steam Turbine Delivery	April 1996
Gas Turbine Delivery	July 1996
Switchyard Energized	November 1996
First Power	January 1997
Commercial Operation	March 1997

be controlled by a steam-to-fuel ratio controller. The compressed mixture of air and combustion products will then expand through the power turbine, converting thermal energy to mechanical energy. This mechanical energy will rotate both the compressor used to compress inlet air and the electrical generator to produce electrical energy. Exhaust gas will exit each power turbine at approximately 1,100° F and will be sent to its associated HRSG.

2.0 HEAT RECOVERY STEAM GENERATOR (HRSG)

The hot exhaust gases from each gas turbine unit will flow to its associated HRSG unit. Exhaust gas entering the HRSGs at approximately 1,100° F will be cooled to approximately 190° F when it leaves the HRSGs, with the heat recovered to heat feedwater and to generate steam. Duct burners will be installed within the HRSGs so additional heat can be added to the HRSGs when necessary. The gas turbine exhaust gas contains sufficient oxygen to support combustion at the duct burner and therefore, external combustion air to the HRSG burners will not be required. As shown on the Process Flow Diagram in Item VII.A of this application, the HRSGs will contain different sections which are used to recover heat and generate steam. The HRSG sections will be arranged so that the operating temperature of the sections progressively drop as the exhaust gases are cooled.

Each duct burner system will be sized for a maximum of 450 MMBtu/hr HHV heat input. The duct burners will be fired with only natural gas. The steam from the HRSG will be used to drive its associated 104 MWe steam turbine. Steam for export to the steam host will be temperature and pressure controlled to the steam host's specifications. Steam for injection into the gas turbine combustors for nitrogen oxides (NO_x) control will be extracted from the steam turbine and desuperheated and pressure controlled to about 360 psig, 475° F.

The duct burners will be used to compensate for reduced turbine-generator output due to higher ambient temperature, increased steam sales demand, or degraded gas turbine performance. Plant output will be maintained at the 500 MWe nominal net plant capacity by regulating duct burner firing and generating the appropriate quantity of high pressure steam to produce the required steam turbine-generator output.

3.0 SELECTIVE CATALYTIC REDUCTION (SCR)

A Selective Catalytic Reduction (SCR) system will be installed within each HRSG to reduce NO_x emissions. In the SCR process, ammonia injected into the gas turbine exhaust gas reacts with NO_x and oxygen in the exhaust gas to form nitrogen and water. The chemical reactions

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

and

$$6\ NO_2 + 8\ NH_3 \rightarrow 7\ N_2 + 12\ H_2O$$

will take place on the surface of a catalyst. Blocks of catalyst elements will be assembled together to fill the full cross-section of the boiler, so that the entire exhaust gas stream flows uniformly through the catalyst unit. The catalyst unit location within the HRSG will be selected so that exhaust gas passing through the catalyst is in the catalyst's most active temperature range.

The SCR system will include the assembled blocks of catalyst elements, an anhydrous ammonia storage tank (12,000 gallon), ammonia vaporizer, accumulator, ammonia/air mixer, air fan, ammonia distribution grid upstream of the catalyst in the HRSG, and flow controls. The SCR will be designed for a nominal 80% reduction of flue gas NO_x emissions when firing natural gas and a nominal 77% reduction when firing fuel oil. No more than 10 ppm of unreacted ammonia will remain in the flue gas.

4.0 STEAM TURBINE AND CONDENSER

Steam produced in each HRSG will be expanded through nominal 104 MWe steam turbines, driving generators to produce electric power. Steam leaving the steam turbines will then be directed to the condensers and recycled back to the HRSGs.

5.0 AUXILIARY STEAM BOILER

An auxiliary steam boiler will be installed to serve as a backup source of steam for the adjacent industrial facility. The boiler will be designed to produce up to 130,000 lb/hr of steam and

will use primary natural gas with fuel oil as backup at a maximum firing rate of about 156 MMBtu/hr. NO_x emissions from the boiler will be reduced by the use of a low-NO_x burner combined with flue gas recirculation which involves extracting a portion of the boiler flue gas and returning it to the burner.

6.0 COOLING TOWER

Non-contact cooling water used to condense turbine exhaust steam in the condenser and for other plant cooling needs will be recycled through a cooling tower where heat will be rejected to the atmosphere. Treated effluent from the City of Cleburne's sewage treatment plant will be used for cooling tower makeup.

7.0 FUEL OIL STORAGE/HANDLING

Two 35,000 barrel fuel oil tanks will be provided. The fixed-roof welded steel tanks will operate at atmospheric pressure. Two 100 percent capacity fuel oil pumps will be provided to pump from the fuel oil storage tank to the gas turbines.

Fuel oil deliveries will be made by truck. Unloading systems and pumps will be provided to unload two trucks at the same time. The unloading areas will be curbed and surfaced to contain oil spills, with drains from the unloading areas piped to an oil/water separator.

8.0 EMERGENCY GENERATOR

There will not be a diesel driven emergency generator permanently installed at the plant. Provision will be made to enable the connection of a portable 1,000 kW, three-phase diesel generator to the plant's electrical system in the event that the plant is shut down and utility power is out of service. The diesel engine driven generator will burn the same fuel oil used as gas turbine backup fuel.

9.0 FIRE PROTECTION SYSTEM PUMPS

A fire water system sized to deliver 2,000 gpm of water will be provided to protect plant facilities against fire. The system will include a fire water supply loop; fire hydrants, fire monitors, and hoses located at appropriate locations. One 200 hp diesel fire pump and one electric drive fire pump will be installed to maintain the required fire water pressure.

10.0 STACK

One stack approximately 18 feet in diameter and 110 feet high will be provided at each HRSG exhaust. The stack will have monitoring ports and an access platform.

11.0 MISCELLANEOUS EQUIPMENT

The proposed generation facility will include the following miscellaneous equipment:

- air compressors, dryers, and receivers for instrument and plant air systems
- continuous boiler blowdown tanks vented to the deaerators, and boiler blowdown tanks vented to the atmosphere
- lubrication oil storage tank(s) with transfer pump(s)
- chemical feed skids with tanks, mixers, and feed pumps for boiler and feedwater treatment, and for cooling water treatment
- control room mechanical equipment including air handling unit, hot water heater, locker rooms and fire extinguishers

12.0 CHEMICAL STORAGE

Chemicals will be transported to the site by truck. Storage volumes provided are determined by rates of consumption, customary delivery volumes available from suppliers, and the reliability of supply.

12.1 AMMONIA STORAGE

Anhydrous ammonia for use with the SCR system for control of NO_x emissions will be stored in a 12,000 gallon welded steel pressure tank designed to operate without emissions to the atmosphere. The ammonia tank will be designed and tested for 250 psig internal pressure in accordance with Section VIII of the ASME Boiler and Pressure Vessel Code. Pressure within the ammonia tank will vary with ambient temperature, from 16 psig at 0° F to 197 psig at 100° F.

12.2 SULFURIC ACID STORAGE

Sulfuric acid for demineralizer regeneration and cooling tower pH control will be stored in a 6,000 gallon welded steel horizontal tank. The acid will be stored at a 93% concentration. The acid tank will be operated at atmospheric pressure.

12.3 CAUSTIC STORAGE TANK

Caustic soda (sodium hydroxide) for demineralizer regeneration will be stored in a 6,000 gallon welded steel horizontal tank. The caustic will be stored at a 50% concentration. The caustic tank will be operated at atmospheric pressure and will be located indoors.

12.4 BOILER AND COOLING TOWER WATER TREATMENT CHEMICAL STORAGE

Chemicals for boiler feedwater treatment and cooling tower water treatment will be stored indoors in small tanks. Three storage tanks are anticipated for boiler feedwater chemicals and two storage tanks for cooling water chemicals.

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ITEM VII.C

TNRCC MATERIAL BALANCE TABLE

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TABLE 2

MATERIAL BALANCE

Turbines/HRSGs

This material balance table is used to quantify possible emissions of air contaminants and special emphasis should be placed on potential air contaminants, for example: If feed contains sulfur, show distrubiton to all products. Please relate each material (or group of materials) listed to its respective location in the process flow diagram by assigning point numbers (taken from the flow diagram) to each material.

LIST EVERY MATERIAL INVOLVED IN EACH OF THE FOLLOWING GROUPS	Point No. from Flow Diagram	Process Rate * (lbs/hr or SCFM) standard conditions: 70°F 14.7 PSIA. Check appropriate column at right for each process.	Measurement	Estimation	Calculation
1. Raw Materials - Input					
Air (Turbine)		3,347,082 lb/hr		X	
Wet Injection		97,100 lb/hr		X	
Makeup Water		102,700 lb/hr		X	
Anhydrous Ammonia		100 lb/hr		X	
2. Fuels - Input					
Turbine Fuel		1769.0 MMBtu/hr		X	
Duct Burner Fuel		70.2 MMBtu/hr (Avg)/ 450 MMBtu /hr (Design)		X	
3. Products & By-Products - Output					
Electricity		171,790 KW (turbine)		X	
Electricity		83,710 KW (steam)		X	
Steam		44,000 lb/hr		X	
4. Solid Wastes - Output		N/A			
5. Liquid Wastes - Output		N/A			
6. Airborne Waste (Solid) - Output					
Particulate		18.0 lb/hr			X
PM_{10}		17.1 lb/hr			X
7. Airborne Wastes (Gaseous) - Output (Based on design duct burner fuel)					
NO_x		63.5 lb/hr			X
CO		113.1 lb/hr			X
SO_2		18.3 lb/hr			X
VOC		18.4 lb/hr			X
Ammonia		29.1 lb/hr			

* Annualized averages based on 59°F ambient temperature and 58% relative humidity.
Note: These averages are on a per unit basis.

TABLE 2

MATERIAL BALANCE

Boiler

This material balance table is used to quantify possible emissions of air contaminants and special emphasis should be placed on potential air contaminants, for example: If feed contains sulfur, show distrubiton to all products. Please relate each material (or group of materials) listed to its respective location in the process flow diagram by assigning point numbers (taken from the flow diagram) to each material.

LIST EVERY MATERIAL INVOLVED IN EACH OF THE FOLLOWING GROUPS	Point No. from Flow Diagram	Process Rate * (lbs/hr or SCFM) standard conditions: 70°F 14.7 PSIA. Check appropriate column at right for each process.	Measurement	Estimation	Calculation
1. Raw Materials - Input					
Air		131,602.6 lb/hr		X	
Feed Water		133,900 lb/hr		X	
2. Fuels - Input					
Fuel (Natural Gas or Fuel Oil)		156.2 MMBtu/hr		X	
3. Products & By-Products - Output					
Steam		130,000 lb/hr		X	
4. Solid Wastes - Output		N/A			
5. Liquid Wastes - Output		N/A			
6. Airborne Waste (Solid) - Output					
Particulate		1.3 lb/hr			X
PM_{10}		1.3 lb/hr			X
7. Airborne Wastes (Gaseous) - Output					
NO_X		9.8 lb/hr			X
CO		28.0 lb/hr			X
SO_2		1.4 lb/hr			X
VOC		0.98 lb/hr			X

Espey, Huston & Associates, Inc.

ITEM VIII

CONSIDERATIONS FOR GRANTING A PERMIT

ITEM VIII
CONSIDERATIONS FOR GRANTING A PERMIT

Compliance with the requirements of each section of Rule 116.111 of the TNRCC Regulation VI is discussed below as it relates to this permit application:

116.111(1) - PROTECTION OF PUBLIC HEALTH AND WELFARE

As outlined below, the emissions from the project will comply with all rules and regulations of the TNRCC and with the intent of the Texas Clean Air Act, including the protection of the health and physical property of the people. There are no schools located within 3,000 feet of the Tenaska site.

GENERAL RULES

Rule 101.4 - Nuisance

Emissions from the project will not adversely affect human health or welfare, animal life, vegetation, or property, or interfere with the normal use and enjoyment of animal life, vegetation, or property. Dispersion modeling will be performed to demonstrate compliance with all National Ambient Air Quality Standards (NAAQS) for particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}), sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon monoxide (CO) and with TNRCC property-line standards for total suspended particulate matter (TSP) and SO_2. The results of the dispersion modeling will be submitted in a separate document in support of this application after the proposed controls and emissions calculations are accepted by the TNRCC air quality staff. It is expected that the impacts resulting from the project will be in compliance with all Federal and state air quality standards.

Rule 101.5 - Traffic Hazard

Emissions from the project will not cause or have a tendency to cause a traffic hazard or to interfere with normal road use.

Rule 101.20 - Compliance with Environmental Protection Agency Standards

(1) The applicability of the New Source Performance Standards is discussed under Section 116.111(4).

(2) The applicability of the National Emission Standards for Hazardous Air Pollutants is discussed under Section 116.111(5).

(3) The applicability of the Prevention of Significant Deterioration regulations is discussed under Section 116.111(8).

Rule 101.21 - Compliance with the National Primary and Secondary Ambient Air Quality Standards

Atmospheric dispersion modeling will be performed to demonstrate that emissions from the project will not cause or contribute to an exceedance of primary or secondary NAAQS for PM_{10}, SO_2, NO_2, or CO. The results of this modeling will be provided in a future submittal to the TNRCC air quality staff.

REGULATION I - CONTROL OF AIR POLLUTION FROM VISIBLE EMISSIONS AND PARTICULATE MATTER

Rule 111.111 - Visible Emissions: Requirements for Specified Sources

(a)(1) Stationary Sources - The opacity of emissions from the project will not exceed 20% opacity averaged over a six minute period. The gas turbine/HRSG systems will be operated in accordance with manufacturer's specifications and will utilize proper combustion techniques such

that PM emissions will be minimized. The total flow rate out of each gas turbine/HRSG unit assuming 59° F ambient air at the inlet will be approximately one million actual cubic feet per minute. However, the opacity of emissions from the project will not exceed 15% averaged over a 6-minute period; therefore, an optical instrument capable of measuring the opacity of emissions from each vent will not be required by this rule.

(a)(4) Gas Flares - This permit application is not for a gas flare at this site; therefore, Rule 111.111(a)(4) is not applicable to this project.

(a)(5) Motor Vehicles - This permit application does not involve emissions from motor vehicles; therefore, Rule 111.111(a)(5) is not applicable to this project.

(a)(6) Railroad Locomotives and Ships - Railroad locomotives or ships will not operate at this project site; therefore, Rule 111.111(a)(6) is not applicable to this project.

(a)(7) Structures - The gas turbine/HRSG units will not be enclosed by a building; thus, this rule is not applicable to the project.

Rule 111.121 - Incineration

This permit application is not for an incineration device; therefore, this rule is not applicable to the project.

Rule 111.151 - Allowable Emission Limits

The maximum particulate matter emission rate from each gas turbine/HRSG will occur when firing fuel oil (diesel) and will be no more than 68.9 lb/hr compared to the corresponding allowable particulate matter emission rate specified in Rule 111.151 of 266.94 lb/hr. The effective stack height of the HRSG stack will be about 363 feet which is greater than the standard effective stack height of about 137 feet. For details of these calculations, see Appendix C.

The maximum particulate matter emission rate from the auxiliary boiler will also occur when firing fuel oil and will be no more than 7.4 lb/hr compared to the corresponding allowable particulate matter emission rate specified in Rule 111.151 of 36.38 lb/hr. The effective stack height of the HRSG stack will be about 163 feet which is greater than the standard effective stack height of about 44 feet. For details of these calculations, see Appendix C.

Rule 111.153 - Emission Limits for Steam Generator

Each HRSG unit proposed for the project will have a maximum heat input of approximately 450 MMBtu/hr and will be fired with only natural gas. Rule 111.153 is not applicable to the proposed HRSG units since a solid fossil fuel will not be burned and the maximum heat input is below 2,500 MMBtu/hr.

Rule 111.155 - Ground Level Concentration

Modeling will be performed to demonstrate that emissions from the project will not exceed the net ground level concentrations as specified in this rule. The results of this modeling will be provided in a future submittal to the TNRCC air quality staff.

REGULATION II - CONTROL OF AIR POLLUTION FROM SULFUR COMPOUNDS

Rule 112.3 - SO_2 Net Ground Level Concentration

Modeling will be performed to demonstrate that emissions from the project will not exceed the net ground level concentrations as specified in this rule. The results of this modeling will be provided in a future submittal to the TNRCC air quality staff.

Rule 112.9 - Allowable SO_2 Emission Rates - Combustion of Liquid Fuel

As shown in the attached emissions calculations (see Appendix C), when firing fuel oil fuel, the maximum SO_2 concentration from each gas turbine/HRSG stack will be no more than

12.6 ppmvd compared to the corresponding allowable SO_2 emission rate of 440 ppmv. However, the effective stack height is calculated to be about 363 feet which is less than the standard effective stack height of 431 feet. Therefore, the maximum allowable SO_2 concentration in the exhaust gas must be reduced to 311 ppmv in accordance with Rule 112.9(b). The SO_2 emissions from the gas turbine/HRSGs will be in compliance with this reduced standard (see Appendix C for detailed calculations). The gas turbine/HRSGs will not be equipped with SO_2 control equipment and will therefore, not be required to install a continuous emissions monitoring system for SO_2 by this rule.

Also shown in the attached emissions calculations (see Appendix C), when firing fuel oil, the maximum SO_2 concentration from the auxiliary boiler stack will be no more than 30.9 ppmvd compared to the corresponding allowable SO_2 emission rate of 440 ppmv. The effective stack height is calculated to be about 163 feet which is greater than the calculated standard effective stack height of about 76 feet. (See Appendix C for details of this calculation.) The gas turbine/HRSGs will not be equipped with SO_2 control equipment and will therefore, not be required to install a continuous emissions monitoring system for SO_2 by this rule.

REGULATION III - CONTROL OF AIR POLLUTION FROM TOXIC MATERIALS

The project is not a source of inorganic fluoride or beryllium emissions. In addition, this application does not include the construction of a nonferrous smelter or lead smelter. Therefore, Regulation III is not applicable to this facility.

REGULATION IV - CONTROL OF AIR POLLUTION FROM MOTOR VEHICLES

This permit application does not involve emissions from motor vehicles. In addition, the project will be located in Johnson County. Therefore, Regulation IV does not apply to this site.

REGULATION V - CONTROL OF AIR POLLUTION FROM VOLATILE ORGANIC COMPOUNDS

The project is located in Johnson County and is not a source subject to Regulation V; therefore, Regulation V does not apply.

REGULATION VII - CONTROL OF AIR POLLUTION FROM NITROGEN COMPOUNDS

The proposed project will be located in Johnson County and is not a source subject to Regulation VII; therefore, Regulation VII does not apply.

REGULATION VIII - CONTROL OF AIR POLLUTION EPISODES

The project will be operated in compliance with the General Rules and the applicable Air Pollution Episode requirements of Regulation VIII. Rule 118.5, Emission Reduction Plan, is not applicable to this site as it is located in Johnson County.

REGULATION IX - CONTROL OF AIR POLLUTION FROM CARBON MONOXIDE

The project will be located in Johnson County and will not involve CO emissions from any unit listed in Regulation IX; therefore, Regulation IX is not applicable.

REGULATION X - CONTROL OF AIR POLLUTION FROM HAZARDOUS WASTE OR SOLID WASTE MANAGEMENT FACILITIES

This permit application is not for a hazardous waste or solid waste management facility; therefore, Regulation X, Subchapter A does not apply. Tenaska will operate in compliance with all applicable requirements of Regulation X, Subchapter B.

REGULATION XI - CONTROL OF AIR POLLUTION FROM MUNICIPAL SOLID WASTE FACILITIES

This permit application is not for a municipal solid waste facility; therefore, Regulation XI does not apply.

REGULATION XII - FEDERAL OPERATING PERMITS

As the project will be defined as a major source under Rule 122.10, the requirements of Regulation XII will be applicable to this site. Tenaska will comply with the applicable requirements of Regulation XII and will submit an application to the TNRCC for a Federal Operating Permit as required by this rule.

116.111(2) - MEASUREMENT OF EMISSIONS

Tenaska will comply with permit provisions for measuring the emissions of significant air contaminants.

116.111(3) - BEST AVAILABLE CONTROL TECHNOLOGY

The project will utilize the best available control technology with consideration given to the technical practicability and economic reasonableness of reducing or eliminating the emissions from the facility. Section VI.D of this application contains a detailed discussion of the control technology which is utilized at this facility.

116.111(4) - FEDERAL NEW SOURCE PERFORMANCE STANDARDS

The project will be subject to NSPS Subpart Da, Db and GG, as discussed below:

Subpart D - Standards of Performance for Fossil-Fuel-Fired Steam Generators for Which Construction is Commenced After August 17, 1971.

As discussed below, the project's duct burner-fired HRSG units are subject to Subpart Da. Therefore, the HRSG are not covered by Subpart D as provided for in 40 CFR 60.40(e).

The auxiliary boiler will have a maximum fuel input of about 156 MMBtu/hr which is less than the applicable rate of 250 MMBtu/hr as specified by this subpart for a fossil-fuel-fired steam generating unit. Therefore, the requirements of this subpart are not applicable to the auxiliary boiler.

Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978.

The proposed project's duct burner-fired HRSG units will be subject to the requirements of Subpart Da as the maximum heat input of 450 MMBtu/hr per unit exceeds the applicability level of 250 MMBtu/hr heat input based on firing only natural gas. On or after the date of the initial performance test is completed for the HRSG, particulate matter emissions from the proposed facility will not exceed the standard of 0.03 lb/MMBtu heat input for natural gas firing. The opacity of emissions from the HRSG will not exceed 20% averaged over a 6-minute period except for one 6-minute period per hour of not more than 27% as allowed by this standard. SO_2 emissions from the proposed facility will not exceed the standard of 0.8 lb/MMBtu heat input and 10% of potential combustion concentration, calculated in accordance with 40 CFR 60.41a, based on a 30-day rolling average basis. NO_x emissions from the proposed facility will not exceed the standard of 0.2 lb/MMBtu based on a 30-day rolling average basis. As shown on the vendor representations in Appendix F for the HRSG duct burners, the PM and NO_x emissions from the duct burners will not exceed 0.01 lb PM/MMBtu (HHV) and 0.08 lb NO_x/MMBtu (HHV),

respectively, when burning natural gas. Therefore, the duct burners will comply with the requirements of this subpart.

The auxiliary boiler will have a maximum fuel input of about 156 MMBtu/hr which is less than the applicable rate of 250 MMBtu/hr as specified by this subpart. Therefore, the requirements of this subpart are not applicable to the auxiliary boiler.

Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

As discussed above, the project's duct burner-fired HRSG units are subject to Subpart Da. Therefore, the HRSGs are not covered by Subpart Db, as provided for in 40 CFR 60.40b(e).

The proposed auxiliary boiler will be subject to the requirements of Subpart Db as the maximum heat input of 156 MMBtu/hr exceeds the applicability level of 100 MMBtu/hr heat input when firing either natural gas or fuel oil. As the boiler may be fired with distillate fuel oil, it is subject to the nitrogen oxides standards under this subpart. On or after the date of the initial performance test is completed for the boiler, NO_x emissions from the proposed facility will not exceed the standard of 0.2 lb/MMBtu heat input based on a 30-day rolling average basis when firing natural gas or distillate fuel oil. As shown on the vendor representations in Appendix F for the boiler burner, the NO_x emissions from the boiler will not exceed 0.06 lb NO_x/MMBtu when burning natural gas or 0.1 lb NO_x/MMBtu when burning fuel oil. Therefore, the auxiliary boiler will comply with the requirements of this subpart.

Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units

As discussed above, the project's duct burner-fired HRSG units have a maximum heat input capacity of up to 450 MMBtu/hr. The auxiliary boiler has a maximum heat input capacity of 156 MMBtu/hr. These levels exceed the applicability level of 10 - 100 MMBtu/hr of Subpart Dc. Therefore, the HRSGs and the boiler are not covered by Subpart Dc, as provided for in 40 CFR 60.40c(a).

Subpart GG - Standards of Performance for Stationary Gas Turbines

The project's stationary gas turbines will be subject to the requirements of Subpart GG since the maximum heat input exceeds the applicability level of 10 MMBtu/hr (10.7 gigajoules/hr). The gas turbines will be operated so as to comply with the calculated allowable concentration of NO_x in the exhaust as contained in 40 CFR 60.332(a)(1). On or after the initial performance test is completed, SO_2 emissions from the proposed facility will not exceed the standard of 150 ppmvd contained in 40 CFR 60.333(a). Based on the emissions calculations in Appendix C, the maximum SO_2 concentration in the turbine exhaust is estimated to be 12.1 ppmvd when firing fuel oil. The fuel utilized by the gas turbine units will not contain sulfur in excess of 0.05 %wt.

Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels for Which Construction, Reconstruction, or Modification Commences After July 23, 1984

The project will include two 35,000-barrel fixed-roof tanks for the storage of fuel oil. The control requirements of Subpart Kb are not applicable to these tanks as the vapor pressure of the fuel stored is below the applicability level as contained in 40 CFR 60.110b(c). Records showing the dimensions and capacity of the tanks will be kept on site for the life of the tanks as required by 40 CFR 60.116b(a) and (b).

116.111(5) - NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

There are no National Emission Standards for Hazardous Air Pollutants (NESHAPs) applicable to this facility.

116.111(6) - PERFORMANCE DEMONSTRATION

It is expected that the project will achieve the performance as described in this permit application.

116.111(7) - NON-ATTAINMENT REVIEW

Johnson County has not been designated non-attainment for any criteria pollutant and the National Ambient Air Quality Standards have not been exceeded nor predicted to be exceeded; therefore, Rule 116.111(7) is not applicable.

116.111(8) - PREVENTION OF SIGNIFICANT DETERIORATION REVIEW

The proposed project is located in an attainment area and will be defined as a major source under PSD rules for CO, NO_x, PM, PM_{10}, SO_2, and VOC; therefore, the proposed project will undergo preconstruction review and permitting as required by the Federal PSD regulations for these pollutants. This permit application will address all of the elements necessary for this type of facility as required for submittal to the TNRCC for a PSD permit.

116.111(9) - AIR DISPERSION MODELING

Dispersion modeling will be performed to demonstrate compliance with all NAAQS for PM_{10}, SO_2, NO_x, and CO and with TNRCC property-line standards for TSP and SO_2. The results of the dispersion modeling will be submitted in a separate document in support of this application after the proposed controls and emissions calculations are accepted by the TNRCC air quality staff. It is expected that the impacts resulting from the project will be in compliance with all Federal and state air quality standards.

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ITEM XIII
AIR QUALITY ANALYSIS

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ITEM XIII
AIR QUALITY ANALYSIS

The air quality analysis in support of this permit application will be conducted after a preliminary determination has been made by the TNRCC Air Quality Permits Engineer that the emissions calculations and controls proposed as BACT are acceptable. This analysis will then be submitted under a separate document as a supplement to this document.

Espey, Huston & Associates, Inc.

ITEM XIV
CONTEMPORANEOUS CHANGES

ITEM XIV
CONTEMPORANEOUS CHANGES

The proposed project is considered to be a "new source" under TNRCC and PSD rules. Currently, no other source exists within the project's property line. Therefore, there will be no contemporaneous emission increases or decreases associated with this permit application.

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ITEM XV

AIR QUALITY MONITORING

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ITEM XV
AIR QUALITY MONITORING

The PSD regulations require that ambient air quality monitoring data be provided for each pollutant which will be emitted in a "significant amount", unless the predicted ambient impact caused by the proposed significant emissions is less than the prescribed significant monitoring value contained in 40 CFR 52.21(i)(8)(i). Atmospheric dispersion modeling of emissions will be conducted so as to demonstrate that either: (1) the emissions due to the project will be less than the specified significant monitoring value; or (2) the predicted ambient air quality impacts due to the non-project sources in the area will be less than the specified significant monitoring value. In the event that predicted air quality impacts are predicted to be above the specified monitoring values, the TNRCC and EPA will generally allow an applicant to use monitoring data gathered by the TNRCC or other acceptable monitoring program to satisfy the monitoring requirements, if certain criteria are met. The results of the dispersion modeling will be submitted in a separate document in support of this application after the proposed controls and emissions calculations are accepted by the TNRCC air quality staff.

Espey, Huston & Associates, Inc.

ITEM XVI
ADDITIONAL IMPACTS ANALYSIS

ITEM XVI
ADDITIONAL IMPACTS ANALYSIS

GROWTH

It is estimated that the construction phase of the Cleburne Cogeneration Project will create 250 person-years of employment. Peak staffing during construction will be approximately 300 people with construction taking place over approximately 18 months. In addition, approximately 50 person-years of engineering staff will be required at the site. An estimated 20 to 25 permanent jobs, with a total annual payroll of $1.3 million including benefits and payroll taxes, will be created by the operation of the plant. This number does not include temporary or contract workers required for maintenance or outside support services.

It is assumed that some segment of the local unemployed work force will fill the short-term construction positions, as well as the long-term operation positions, and that no significant project-related immigration will occur. Secondary and induced financial benefits would be expected to accrue to the local economy. No significant secondary or induced impacts to local off-site land uses, community services, public infrastructures, or housing is anticipated to result from this project.

SOILS AND VEGETATION

The following background information on area soils and vegetation was taken from the Soil Survey of Johnson County, Texas, published by the U.S. Department of Agriculture (1985).

Soils in the immediate vicinity of the project site belong to the Ponder, Sanger, Slidell, Lott and Medlin series. The Ponder series consists of deep, moderately well drained, clayey soils on uplands. Slopes range from 1 to 5%. This series occupies approximately 3.8% of the county and is listed as a prime farmland soil. The Sanger series consists of deep, well drained, clayey soils on uplands. Slopes range from 1 to 5%. This series occupies approximately 7% of the county and

is listed as a prime farmland soil. The Slidell series consists of deep, well drained, clayey soils on uplands. Slopes range from 0 to 3%. This series occupies approximately 2.9% of county and is listed as a prime farmland soil. The Lott series consists of deep, well drained, clayey soils on uplands. Slopes range from 1 to 3%. This series occupies approximately .5% of the county and is listed as a prime farmland soil. The Medlin series consists of deep, well drained, clayey soils on uplands. Slopes range from 5 to 15%. This soil occupies approximately .2% of the county and is not listed as a prime farmland soil due to erosion problems and its shrink\swell characteristic.

The Ponder series occupies a Claypan Prairie site with approximately 90 % grasses, 5% forbes and 5% woody vegetation. This series, with favorable range conditions, can produce approximately 5500 pounds per acre of forage per growing season. The Sanger and Slidell Series occupy a Blackland range site with approximately 85% grasses, 10% forbes and 5% woody vegetation. These series, with favorable range conditions, can produce approximately 6,000 pounds per acre of forage per growing season. The Lott series occupies a Clay Loam range site with approximately 90% grasses, 5% forbes and 5% woody vegetation. This series, with favorable range conditions, can produce approximately 6,500 pounds per acre of forage per growing season. The Medlin series occupies an Eroded Blackland range site with approximately 85% grasses, 10% forbes and 5% woody vegetation. This series, with favorable range conditions, can produce approximately 5,000 pounds per acre of forage per growing season.

Pollutant emissions from construction activity will result in minor short-term impacts on air quality in the immediate vicinity of the project site, including increased levels of particulate matter and vehicular exhaust emissions. However, it is expected that levels of pollutants resulting from construction will remain below national ambient air quality standards (NAAQS). An air quality analysis of emissions from the project will be conducted to demonstrate compliance with the NAAQS for NO_x, CO, SO_2 and PM/PM_{10}. As a result of the project, the area classification of attainment for NO_x, CO, SO_2 and for PM/PM_{10} will not change and no long-term adverse impacts to soils or vegetation are anticipated.

VISIBILITY

The Wichita Mountains Wilderness Area in Oklahoma was modeled for visual impact screening and analysis of the plume from the cogeneration project. This area is approximately 273 kilometers (km) north-northwest from the site of the proposed project. Emissions from the project will not have an adverse impact on visibility in this PSD Class I area as demonstrated by the visibility screening modeling described below.

The visual impact of a plume from the project on the Class I area was examined using the Plume Visual Impact Screening Model (VISCREEN). The VISCREEN model was run in the Screening Level 1 mode following the guidance in EPA's Workbook for Plume Visual Impact Screening and Analysis (EPA-450/4-88-015). The PM emissions (163.34 tpy) and the NO_x emissions (599.42 tpy; assumed as NO_2) from the proposed project, assuming natural gas and fuel oil (720 hours) were used during the year, were modeled. Regional background visual ranges were input to the model following guidance from the workbook referenced above. The model was run with the default values for the remainder of the input parameters. The report generated by the VISCREEN model for the Class I area is included on the following page. The results of the modeling demonstrated that the cogeneration project will not cause any adverse or significant visual impacts on the Class I area.

ATTACHMENT G

Section 1 - Document

Permit Amendment

Source Analysis & Technical Review

Company	Brazos Electric Power Cooperative, Inc.	Permit Number	25384
City	Cleburne	Project Number	162448
County	Johnson	Account Number	JH-0230-L
Project Type	Amend	Regulated Entity Number	RN100223312
Project Reviewer	Mr. Marc Sturdivant	Customer Reference Number	CN600128821
Site Name	Johnson County Generation Facility		

Project Overview

The Johnson County Generation Facility is an electric generating station located at 831 Sparks Dr, Cleburne, TX 76033, in Johnson County and is owned and operated by Brazos Electric Power Cooperative, Inc. (BEPC). The plant consists of a single combustion turbine equipped with a heat recovery steam generator (HRSG) unit, Emission Point No. (EPN) E-CT/HRSG, and served with ancillary equipment. BEPC wishes to amend their permit to authorize emissions from planned maintenance, startup and shutdown (MSS) activities. BEPC would like to revise Special Conditions 21A to make it clear that it is referring to base load operations, and to revise Special Condition 27A, B, and C, to define planned start-ups and shutdowns as turbine operations at less than 120 MW. MSS emissions from EPN E-CT/HRSG will be added to the MAERT as well as a new EPN MSSFUG.

Emission Summary

Air Contaminant	Current Allowable Emission Rates (tpy)	Proposed Allowable Emission Rates (tpy)	Change in Allowable Emission Rates (tpy)
PM	65.2	65.2	<0.01
PM_{10}	61.9	61.9	<0.01
$PM_{2.5}$	-	<0.01	<0.01
VOC	42.9	42.95	0.05
NO_X	272.82	272.82	<0.01
CO	462.6	462.6	0.00
SO_2	72.5	72.5	0.00
NH_3	130.5	130.5	<0.01
Pb	<0.1	<0.1	0.00

Compliance History Evaluation - 30 TAC Chapter 60 Rules

A compliance history report was reviewed on:	April 27, 2011
Compliance period:	April 27, 2006-April 27, 2011
Site rating & classification:	5.63, Average
Company rating & classification:	2.69, Average

If the rating is 40<RATING<45, what was the outcome, if any, based on the findings in the formal report:	N/A
Has the permit changed on the basis of the compliance history or rating?	No

Public Notice Information - 30 TAC Chapter 39 Rules

Rule Citation	Requirement	
39.403	Is Public Notice Required?	No
	If no, give reason:	There is no proposed change in character of emissions or the release of any new air contaminant. The emissions increases from all sources are less than the public notice de minimis levels of 30 TAC 39.402 (a)(3)

Construction Permit & Amendment Requirements - 30 TAC Chapter 116 Rules

Rule Citation	Requirement	
116.111(a)(2)(G)	Is the facility expected to perform as represented in the application?	Yes
116.111(a)(2)(A)(i)	Are emissions from this facility expected to comply with all TCEQ air quality Rules & Regulations, and the intent of the Texas Clean Air Act?	Yes
116.111(a)(2)(B)	Emissions will be measured using the following method:	NO_x and CO CEMs and NH_3 monitoring
	Comments on emission verification:	
116.111(a)(2)(D)	Subject to NSPS?	Yes
	Subparts A, Da, & GG,	
116.111(a)(2)(E)	Subject to NESHAP?	No
	Subparts &	
116.111(a)(2)(F)	Subject to NESHAP (MACT) for source categories?	Yes
	Subparts A & ZZZZ	
116.111(a)(2)(H)	Is nonattainment review required?	No
	Is the site located in a nonattainment area?	Yes
	Is the site a federal major source for a nonattainment pollutant?	Yes
	Is the project a federal major source for a nonattainment pollutant by itself?	No
	Is the project a federal major modification for a nonattainment pollutant?	No
	Did the project emission increases for nonattainment pollutant minus the two-year average actual emissions trigger netting?	No
	If yes, attach Table 1N & 9N. If no, explain:	
	Is the contemporaneous increase significant?	No
	If the contemporaneous increase is significant a nonattainment review is required.	
116.111(a)(2)(I)	Is PSD applicable?	No
	Is the site a federal major source (100/250 tons/yr)?	Yes
	Is the project a federal major source by itself?	No
	Is the project a federal major modification?	No
	Did project emission increases, without decreases, for pollutant of concern, minus the two-year average actual emissions trigger netting?	No

	Was the contemporaneous increase significant?		No
	If yes, explain:		
	Is the change excluded by 40 CFR 52.21(b)(2)(iii)?		No
	If yes, explain:		
116.111(a)(2)(L)	Is Mass Emissions Cap and Trade applicable to the new or modified facilities?		No
	If yes, did the proposed facility, group of facilities, or account obtain allowances to operate:		
116.140 - 141	Permit Fee: $ 900.00	Fee certification:	R111786

Title V Applicability - 30 TAC Chapter 122 Rules

Rule Citation	Requirement	
122.10 (13)(A)	Is the site a major source under FCAA Section 112(b)?	Yes
	Does the site emit 10 tons or more of any single HAP?	Yes
	Does the site emit 25 tons or more of a combination?	Yes
122.10 (13)(C)	Does the site emit 100 tons or more of any air pollutant?	Yes
122.10 (13)(D)	Is the site a non-attainment major source?	No
122.602	**Periodic Monitoring (PM) applicability:** Periodic monitoring is applicable because this site is subject to 30 TAC Chapter 122. Periodic monitoring of planned MSS activities in the form of recordkeeping is used for the ILE activities listed in Attachment A consisting of an annual confirmation of the estimated PTE represented for those ILE activities. Recordkeeping and CEMS are used for periodic monitoring of all other planned MSS activities in which emissions are determined based on the duration of each event and compared to the MAERT on a rolling 12 month basis.	
122.604	**Compliance Assurance Monitoring (CAM) applicability:** The site is a major source; however there are no control devices in use during MSS. Therefore, CAM is not applicable.	

Request for Comments

Received From	Program/Area Name	Reviewed By	Comments
Region:	4	Ariel Yeh/Jeremy Baum	No Comments
City:	Cleburne		N/A
County:	Johnson		N/A
Toxicology:			N/A
Compliance:			N/A
Legal:			N/A
Comment resolution and/or unresolved issues:			

Process/Project Description

The Plant is an electric generating facility consisting of a single Westinghouse 501 F combustion turbine, with a nominal output in the range of 250-270 MW, equipped with a 375- MMBtu/hr HRSG. The turbine is authorized to fire both natural gas and fuel oil, but the HRSG is authorized to fire only natural gas. The unit is authorized to operate 8760 hours per year; however, it is limited to 720 hours per year of fuel

oil firing. Emissions of NO_x are contolled through the injection of steam into the combustion turbine exhaust and with an anhydrous ammonia-based selective catalytic reduction (SCR) system. Ancillary equipment at the site includes anhydrous ammonia tank and ammonia delivery system, a fire water pump engine, a sulfuric acid tank, two fuel oil tanks, a cooling water system, and a refrigeration system.

Startups and shutdowns are regular and planned operations and during these periods, emissions of NO_x and CO can exceed the lb/hr limits of the permit. BEPC is requesting an amendment to authorize emissions of NO_x and CO from E-CT/HRSG during these startup and shutdown periods. Experience in operating the plant shows that the onset of startup is best defined as the beginning when fuel is first fed to the unit and ending when the load on the unit reaches 120 MW, approximately 44% of the 270 MW upper range of the turbine as opposed to 30% currently stated in the permit. Likewise, shutdown is defined as beginning when the load drops below 120 MW and ending when fuel is no longer fed to the unit. A review of CEMS data shows that setting 120 MW as the threshold between startup/shutdown and base load, a value equal to 44% of full load adequately takes into account the emission control reaction time and startup operating condition progression. Note, that redefining this threshold as 120 MW would not affect the time limit of 4 hours for a planned startup and 2 hours for a planned shutdown established in Special Condition 28 nor would it cause the value limits set in the MAERT to be exceeded.

Some of the site wide maintenance activities BEPC is requesting authorization for can be characterized as inherently low emitting (ILE) activities. These ILE activities and operations will be included in the permit under attachment A. A new EPN is will also be added to the MAERT, this is EPN MSSFUG.

Some MSS- related maintenance activities with emissions that are too large to be considered ILE will also be considered in the amendment application. BEPC states that the emissions from these activities will not exceed emission limits now established under the current permit. No separate emission allowables for these activities are being proposed. Such activities include, but are not limited to, online turbine optimization activities and online SCR system maintenance.

Pollution Prevention, Sources, Controls and BACT- [30 TAC 116.111(a)(2)(C)]

Emission sources are the turbine exhaust stacks and fugitive emissions associated with planned MSS. Controls consist of low sulfur fuels for SO_2, combustor design for CO, dry low NO_x combustors for NO_x and an aqueous ammonia-based selective catalytic reduction system. The CEMS will give a direct report of NO_X and CO concentrations. During planned MSS when control devices or process equipment are operating outside the design optimal mode and it is technically infeasible to meet the primary BACT emission rates, secondary BACT limits are necessary. These secondary BACT limits are designed to limit emissions during planned MSS activities. Secondary BACT limits are identified in Special Condition Nos. 25 thru 30. These limitations include work practices limiting the duration of startup and shutdown for combustion equipment, minimizes the amount of time combustion equipment is outside the optimal performance mode (in which the process units and controls were designed to work most effectively). The specific maintenance activities identified in the application have been listed as ILE activities in Attachment A of the permit.

Impacts Evaluation - 30 TAC 116.111(a)(2)(J)

Was modeling conducted?	Yes	Type of Modeling:	Screen3
Will GLC of any air contaminant cause violation of NAAQS?		No	
Is this a sensitive location with respect to nuisance?		No	
[§116.111(a)(2)(A)(ii)] Is the site within 3000 feet of any school?		No	
Additional site/land use information: Land surrounding the facility is mainly undeveloped with industrial facilities to the north of the facilities. The nearest residence is less than 1 mile to the north west of the facility.			

Summary of Modeling Results

Emissions from NO_x were modeled using all NO_x sources on site plus background concentrations. The concentrations from the site were predicted to be 148.5 $\mu g/m^3$ and the background was 39.25 $\mu g/m^3$. When added together, the total concentration was below the NAAQS of 188 $\mu g/m^3$. Modeled concentrations of all other pollutants (CO, PM_{10}, $PM_{2.5}$, and NH_3) for the project only fell below the SIL and/or ESL. Therefore emissions from the facility are not expected to have an adverse impact on health or the environment. No further modeling required.

Pollutant	Averaging	Predicted Concentration	SIL	SIL	Background	Total Conc	NAAQS	NAAQS

	Time	(μg/m³)	(μg/m³)		(μg/m³)	(μg/m³)	(μg/m³)	
NO_x	1-hr	148.5	7.5	No	39.25	187.75	188	Yes
NO_x	Annual	11.88	1	No	39.25	51.13	100	Yes
CO	1-hr	395.55	500	Yes				
CO	8-hr	276.885	2000	Yes				
PM_{10}	24-hr	0.009	5	Yes				
$PM_{2.5}$	24-hr	0.009	1.2	Yes				
$PM_{2.5}$	Annual	0.0018	0.3	Yes				
		GLC_{max} (μg/m³)	ESL (μg/m³)					
NH_3		0.072	170	Yes				

Permit Concurrence and Related Authorization Actions

Is the applicant in agreement with special conditions?	**Yes**
Company representative(s):	**David Cabe and Mark Pavelka**
Contacted Via:	**Email**
Date of contact:	**October 17, 2011**
Other permit(s) or permits by rule affected by this action:	**No**
List permit and/or PBR number(s) and actions required or taken:	**N/A**

Project Reviewer	Date	Team Leader/Section Manager/Backup	Date

Headers

Permit Amendment

Source Analysis & Technical Review

Permit No. 25384 Regulated Entity No. RN100223312

Page

Footers

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ATTACHMENT H

List of Johnson Assets
for Asset Number
As of December31, 2011

2/7/2012

Total	$33,179,824.84

Item Number	Quantity	Unit Number	Description	Date Acquired	Current Location	Serial Number	BU	AssetC	Object	Sub	Original Cost	Assigned to
186133	1	1TGAPAR1	Steam Turbine – Turbogenerat	9/15/2006	751		1		314	JOC10	$48,655,996.41	0
186127	1	1SGAPAR1	Heat Recovery Steam Generator	9/15/2006	751		1		312	JOC11	$33,179,824.84	0
186206	1	1GTBPAR1	ST Gen. SU Transformer & Brea	9/15/2006	750		1		346	JOC00	$3,039,272.00	0
186100	1	1FWCPAR2	Condenser -- Turbogenerator U	9/15/2006	751		1		314	JOC10	$2,764,985.00	0
186117	1	1HRCPAR2	Cooling Tower & Equipment --	9/15/2006	751		1		314	JOC10	$2,073,739.05	0
186162	1	1TGAPAR2	Steam Turbine – Accessory El	9/15/2006	751		1		315	JOC10	$1,141,386.44	0
186092	1	1FWAPAR1	Boiler Feed Pumps – Boiler P	9/15/2006	751		1		312	JOC10	$1,105,994.73	0
185872	1	1APCPAR1	480 V Switchgear and MCCs –	9/15/2006	751		1		315	JOC10	$995,836.92	0
186109	1	1HRCPAR1	Circulating Water Pumps/Circ	9/15/2006	751		1		314	JOC10	$967,744.32	0
186102	1	1GTBPAR2	ST Gen. SU Transformer & Brea	9/15/2006	751		1		315	JOC10	$416,960.16	0
186095	1	1FWCPAR1	Condensate Pumps/Condensate S	9/15/2006	751		1		314	JOC10	$414,747.57	0
186437	1	186437	CLOSED CYCLE COOLING WATER HE	4/23/2008	751		1		314	JOC10	$101,655.63	17585
185101	370	185101	ST LUBE OIL COOLER PACK	10/4/2007	JOHNSONPLANT		1		314	JOC10	$51,258.30	17585
189636	1	189636	ST LUBE OIL CONDITIONER	2/19/2009	751		1		314	JOC10	$43,480.77	25857
174606	1	174606	PRDS TRIM ASSEMBLY WITH WATER	9/15/2006	JOHNSONPLANT		1		343	JOC11	$23,133.88	20594
195264	1	195264	CITY WATER LINE TO COOLING TO	8/19/2010	JOHNSONPLANT		1		314	JOC10	$2,509.66	25857

Brazos Electric Power Coopertive, Inc.
Job Closings
Job No. 505 - 515 Johnson County Plt. Rebuild
Energized Date 9/15/2006

Subledger Description	Doc. Type	Explanation/Vendor Name	Amount
Labor-Direc	JY	BEPC Direct Labor	0.00
Misc	OV	Miscellaneous	578,847.84
Meals & Lod	PV	BEPC Meals and Lodging	6645.74
Transportat	PV	BEPC Transportation	4911.88
Misc Suppli	JE	BEPC Miscellaneous Supplies	-114,663.90
Equipment C	PV	Construction Equipment	101,107.89
Rentals	JE	Rental Equipment	206,448.43
Contractors	JE/JJ	Contractor Cost	27,678,663.34
Legal	PV	Legal work	170,786.28
OH-Misc Adm	PV	Overheads & Miscellaneous Admin	1857.03
		Total:	**28,634,604.53**

ATTACHMENT I

Attachment I, Use Calculation Using TCEQ-Mandated Inputs/Variables to Which BEPC Objects

TCEQ Use Determin[illegible] [illegible]plication Section 11 use:
Company: Brazos[illegible] [illegible]c Power Cooperative, Inc.
Plant: Johnson County Generation Facility
Unit: 258 MW 1 x 1 Configuration Combined Cycle Power Plant (1996)
Address: Cleburne, Texas
Project: Tier III Cost Analysis Procedure
Date: 10-Feb-12

I. Assumptions

Pollution Control Property (PC)		Source
Property Cost:	$28,111,986.00	BEC Acctng
Capital Cost ($/KW):	$326.88	PC/TC
Total Capacity (MW):	258	∑(CT+ST)
CT Capacity (MW)	172	BEC 2010 RUS Form 12
ST Capacity (MW)	86	BEC 2010 RUS Form 12
2010 Net Annual ST Generation Capacity (KWhr):	487,215,000	BEC 2010 RUS Form 12
2010 Net Annual ST Generation Capacity (MWhr):	487,215	BEC 2010 RUS Form 12
2010 ST Capacity Factor:	64.67	Energy/(TC * 8760)
2010 Plant Heat Rate (btu/kwhr):	7,782	BEC 2010 RUS Form 12
2010 Plant Heat Rate (mmbtu/kwhr):	0.008	NPHR/1E06
2010 Operating Hours	7,606	BEC 2010 RUS Form 12
Capital Cost Old:	0	
Comparable Technology Cost:	41,280,000	
Comparable Technology:	0	
Design Capacity Factor:	0	
Capacity (MW):	1	

Conversion Factors	
Hrs/yr	8760
KW/MW	1000
lb/kg	2.2
s/hr	3600
btu/mmbtu	1000000

Economic Assumptions		Source
Discount Rate (%)	10.00%	Standard project rate
Periods (Yrs)	30	RUS depreciation
PC Property Fixed O&M Cost ($/KW-yr)	$6,126,060	BEC 2010 RUS Form 12
CT Fixed O&M Costs ($)	$4,084,040	Formula
HRSG O&M Costs ($)	$1,709,943	Formula
Fuel Cost ($/MMBTU)	$4.11	Note 1
PC property Variable Cost ($/MWh)	$5.00	Check with QSE
PC property Variable Cost ($/KWh)	$0.0050	Formula
ERCOT Electricity Pricing ($/MWh)	$44.48	Note 2
Interest Rate (%)	10.00%	

Note 1: Average cost for fuel (2009 - 2011) weighted by monthly steam turbine generation

Note 2: Average Settlement Point price for resource weighted by hourly steam turbine generation, reflected by North Load Zone Market Clearing Price for Energy (MCPE) for Jan 1, 2009 - Nov 30, 2010 and Real-time Resource

Levelized Cost of Energy (LCOE) Model Outputs	
Capitol Recovery Factor (%)	10.61%
LCOE ($/KWh)	0.03079

II. Cost Analysis Procedure

A. $$\frac{[(\text{Production Capacity Factor} \times \text{Capital Cost New}) - \text{Capital Cost Old} - \text{Marketable Product}]}{\text{Capital Cost New}}$$

B. Cost Analysis Procedure Formulas (TCEQ)

Partial Use Determination

$$\frac{[(\text{Production Capacity Factor} \times \text{Capital Cost New}) - \text{Capital Cost Old} - \text{Marketable Product Value}]}{\text{Capital Cost New}}$$

where: Marketable Product Value = $\sum_{t=1}^{n} \frac{\text{Marketable Product Value} - \text{Production Cost}}{(1 + \text{Interest Rate})^n}$

n = estimated useful life in years of years equipment
t = year one
Interest Rate = 10%

C. Cost Analysis Procedure for Pollution Control Property

Marketable Product Value = Electricity Price ($/MWh) x MWh per Year
Direct Cost of Production = Levelized Cost of Energy x KWh per Year

$$\text{LCOE ($/KWh)} = \frac{\text{(Capital Cost} \times \text{Capital Recovery Factor)} + \text{Fixed O\&M Costs}}{\text{Hours per Year} \times \text{Capcity Factor}} + \text{(Fuel Cost} \times \text{Heat Rate)}$$

Capital Recovery Factor (CRF) $\frac{i \times (1+i)^n}{(1+i)^n - 1}$

(PC)	(CRF)		(Annual cost to carry)		(FOM)	(Total Annual FC)	
$28,111,986.00	10.61%	=	$2,982,098.34	+	$1,709,943	$4,692,040.97	
						$0.0096	/kWh
					(Fuel x NPHR)	$0.0320	
					LCOE:	$0.04161	($/kWh)

Attachment I, cont'd

III. Cost Analysis Proc 'alculations For Jack County (Jack 1) HRSG1 and HRSG2

F $\frac{(PCF \times CCN) - CCO - NPVMP}{CCN}$

A. Marketable Product Value (MPV)

Electricity Price $\frac{\$}{MWh} \times \frac{\text{Plant MWh}}{\text{Year}}$ = ($) MPV

$44.48 x 487,215 = $21,671,323.20

B. Production Cost (PC)

Levelized Cost Of Energy (LCOE) $\frac{\$}{KWh} \times \frac{\text{Plant KWh}}{\text{Year}}$ = ($) PC

$0.04161 x 487,215,000 = $20,274,454.44

Net Present Value Marketable Product (NPVMP) Calculation

$\sum_{t=1}^{n} \frac{\text{Marketable Product Value - Production Cost}}{(1 + \text{Interest Rate})^n}$ = NPVMP ($)

$\sum_{t=1}^{n} \frac{\$21,671,323.20 - \$20,274,454.44}{1.10}$ = NPVMP $10,037,697.34 — $10,339,585.86

If MP is <= 0, then MP = 0

C. Production Capacity Factor (PCF)

$\frac{\text{Production Capacity of Existing Equipment or Process}}{\text{Production Capacity of New Equipment or Process}}$ = PCF

$\frac{0}{86 \text{ MW} \times 56.21\%}$ = PCF 1.00

D. Bapital Cost New (CCN)

Pollution Control Property (PC) = CCN $28,111,986.00

E. Capital Cost Old (CCO)

Comparable Technology = CCO $41,280,000.00

Partial Use Determination Calculation

$\frac{(PCF \times CCN) - CCO - MP}{CCN}$ = Partial Use Determination %

$\frac{\$28,111,986.00 - \$41,280,000.00 - \$10,037,697.34}{\$28,111,986.00}$ = -82.55%

Eligible HRSG Costs
(Partial Use Determination % x PC Property) = -$23,205,711.34

TCEQ Use Determination Application Section 11 use:	
Use Percent	-82.55%
Estimated Dollar Value	-$23,205,711.34

$1,396,868.76
$1,064,791.39
$1,064,791.39
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ERCOT NORTH

Quote Date
2/8/2012

Forward Prices ($/MWh)
(Long term model includes capacity)

Forward Month	On Peak (5x16)	7x8	2x16	Wrap	7x24
Feb-12	23.39	17.82	19.31	18.36	20.76
Mar-12	24.75	16.87	18.33	17.41	20.89
Apr-12	27.18	17.52	20.05	18.47	22.53
May-12	31.21	16.57	20.33	17.95	24.22
Jun-12	38.04	17.78	23.78	20.03	28.43
Jul-12	58.75	19.98	26.68	22.61	38.93
Aug-12	59.44	20.98	26.56	22.88	40.96
Sep-12	35.06	17.76	23.33	20.12	26.85
Oct-12	29.33	17.06	20.74	18.31	23.76
Nov-12	26.84	18.41	20.76	19.29	22.81
Dec-12	29.58	20.03	22.71	21.14	24.77
Jan-13	33.68	25.22	28.96	26.59	29.94
Feb-13	33.78	25.88	28.05	26.67	30.06
Mar-13	31.99	22.55	24.58	23.35	27.26
Apr-13	31.73	22.04	25.06	23.09	27.31
May-13	35.38	22.13	27.16	23.98	29.37
Jun-13	42.35	23.41	31.74	26.74	33.68
Jul-13	61.93	28.18	37.15	31.47	45.88
Aug-13	62.22	28.67	36.70	31.62	46.10
Sep-13	39.18	23.29	30.23	26.07	31.90
Oct-13	31.31	22.13	26.91	23.76	27.49
Nov-13	32.16	23.18	26.27	24.41	27.85
Dec-13	33.85	24.46	27.59	25.69	29.38
Jan-14	33.62	29.96	31.27	30.44	31.94
Feb-14	33.72	29.77	31.36	30.35	31.95
Mar-14	29.96	25.67	27.86	26.53	28.08
Apr-14	30.27	24.60	27.97	25.77	27.97
May-14	36.32	24.51	30.36	26.80	31.10
Jun-14	44.29	26.13	34.93	29.43	36.36
Jul-14	63.97	31.25	41.18	34.90	48.65
Aug-14	63.94	31.41	40.67	35.04	48.09
Sep-14	40.66	25.65	32.90	28.37	34.11
Oct-14	32.88	24.19	29.42	25.97	29.39
Nov-14	33.53	25.01	28.49	26.48	29.45
Dec-14	35.04	26.49	29.73	27.68	31.16
Jan-15	36.82	32.13	34.24	32.96	34.70
Feb-15	36.86	31.91	34.28	32.77	34.72
Mar-15	32.39	27.76	30.12	28.68	30.41
Apr-15	32.69	26.86	29.98	27.62	30.10

ERCOT NORTH

Quote Date
2/8/2012

Forward Prices ($/MWh)
(Long term model includes capacity)

Forward Month	On Peak (5x16)	7x8	2x16	Wrap	7x24
May-15	37.08	26.25	32.82	28.98	32.46
Jun-15	43.99	28.09	37.03	31.20	37.45
Jul-15	68.51	33.56	49.66	37.00	52.59
Aug-15	68.46	33.29	43.11	37.14	51.28
Sep-15	40.28	27.08	34.73	29.95	34.77
Oct-15	31.81	25.90	29.58	27.25	29.41
Nov-15	32.44	26.39	29.90	27.79	29.85
Dec-15	33.87	27.76	31.16	29.01	31.31
Jan-16	42.21	28.63	33.28	30.56	35.57
Feb-16	43.07	29.92	32.39	30.80	36.72
Mar-16	41.59	29.16	31.56	29.98	35.73
Apr-16	44.02	29.56	33.82	31.16	37.16
May-16	49.78	30.64	37.95	33.50	40.85
Jun-16	49.44	30.35	40.02	36.72	41.40
Jul-16	54.79	31.79	43.01	36.45	44.34
Aug-16	57.02	34.21	43.29	37.30	47.05
Sep-16	48.83	30.32	38.88	33.53	40.67
Oct-16	45.25	29.23	36.22	31.97	37.97
Nov-16	44.07	31.23	35.20	32.72	38.01
Dec-16	41.82	31.23	36.23	32.80	36.87
Jan-17	43.45	29.90	34.55	31.72	37.01
Feb-17	44.68	31.16	33.78	32.11	38.10
Mar-17	43.43	30.72	33.25	31.58	37.45
Apr-17	45.60	31.62	36.39	33.53	38.89
May-17	51.52	33.67	41.32	36.48	43.60
Jun-17	51.98	34.59	44.29	37.32	44.48
Jul-17	56.57	35.32	47.78	40.19	47.41
Aug-17	59.27	38.36	48.54	41.82	50.45
Sep-17	50.21	33.54	43.51	37.54	43.17
Oct-17	47.41	33.57	41.20	36.97	41.60
Nov-17	46.86	36.09	40.69	37.81	42.03
Dec-17	45.27	36.25	41.09	38.26	41.27
Jan-18	47.11	35.73	41.10	37.73	42.18
Feb-18	50.42	37.19	40.31	38.32	44.08
Mar-18	48.88	37.49	40.72	38.68	43.51
Apr-18	53.44	34.98	40.02	36.87	44.60
May-18	55.65	39.10	47.98	42.36	48.65
Jun-18	59.75	41.71	55.57	46.90	52.90
Jul-18	63.99	45.85	59.52	51.21	56.98

ERCOT NORTH

Quote Date
2/8/2012

Forward Prices ($/MWh)
(Long term model includes capacity)

Forward Month	On Peak (5x16)	7x8	2x16	Wrap	7x24
Aug-18	68.83	49.61	62.79	54.10	61.38
Sep-18	62.65	46.35	58.27	51.39	56.15
Oct-18	55.59	43.23	51.70	46.11	50.80
Nov-18	57.55	44.93	50.65	47.07	51.96
Dec-18	62.00	51.89	57.66	54.28	57.60
Jan-19	65.87	51.10	58.68	53.88	59.55
Feb-19	67.33	51.37	55.68	52.94	59.79
Mar-19	68.67	45.22	49.29	46.82	56.70
Apr-19	72.58	51.82	58.93	54.30	63.24
May-19	75.01	53.59	65.76	58.06	66.08
Jun-19	78.73	58.49	73.22	64.38	70.76
Jul-19	84.34	62.91	78.44	68.62	76.06
Aug-19	87.91	65.39	81.76	71.40	79.21
Sep-19	77.33	58.26	71.92	63.72	69.77
Oct-19	68.57	45.65	55.52	49.01	58.68
Nov-19	66.26	49.71	56.53	52.35	58.52
Dec-19	66.50	53.54	60.39	56.22	60.86
Jan-20	69.59	54.77	62.90	57.75	63.35
Feb-20	71.65	53.46	58.10	55.24	62.78
Mar-20	73.62	45.08	48.97	46.51	59.36
Apr-20	75.45	53.08	60.36	55.61	65.31
May-20	78.63	57.51	71.91	63.49	70.00
Jun-20	83.06	61.90	77.25	67.24	74.98
Jul-20	89.51	66.18	83.24	71.99	80.65
Aug-20	92.69	68.26	86.20	75.29	83.15
Sep-20	79.96	61.15	74.36	66.10	72.57
Oct-20	71.97	54.23	66.56	58.76	65.01
Nov-20	70.35	51.97	58.90	54.74	61.67
Dec-20	69.01	58.35	64.18	60.49	64.52
Jan-21	70.72	55.80	64.87	59.57	64.37
Feb-21	69.66	54.24	58.79	55.90	62.45
Mar-21	76.43	43.25	46.81	44.46	60.30
Apr-21	78.42	52.11	59.26	54.60	66.24
May-21	80.83	58.21	72.82	64.29	71.40
Jun-21	85.71	63.19	79.74	68.94	77.14
Jul-21	91.58	67.33	85.17	74.32	82.12
Aug-21	94.32	68.79	87.72	75.74	84.53
Sep-21	80.33	63.34	74.71	67.60	73.54
Oct-21	74.13	54.43	67.44	59.53	66.13

ERCOT NORTH

Quote Date
2/8/2012

Forward Prices ($/MWh)
(Long term model includes capacity)

Forward Month	On Peak (5x16)	7x8	2x16	Wrap	7x24
Nov-21	70.98	52.21	53.85	54.69	62.28
Dec-21	68.86	58.88	64.04	60.64	64.70
Jan-22	75.29	58.27	67.33	61.82	67.91
Feb-22	73.84	56.94	61.71	58.68	65.90
Mar-22	77.94	43.46	47.03	44.68	61.15
Apr-22	79.06	57.51	65.79	60.61	69.22
May-22	83.57	61.31	75.94	67.05	74.51
Jun-22	87.78	64.98	81.64	70.77	79.09
Jul-22	93.92	71.38	87.35	78.01	84.85
Aug-22	96.74	71.06	89.93	77.48	87.01
Sep-22	81.29	63.59	75.60	68.09	74.25
Oct-22	75.21	52.00	64.42	56.87	65.15
Nov-22	72.23	52.61	59.30	55.11	63.09
Dec-22	69.50	61.53	64.68	62.75	65.80
Jan-23	74.90	60.06	69.40	63.72	68.77
Feb-23	74.43	55.25	59.88	56.93	65.26
Mar-23	78.93	44.91	48.60	46.17	62.40
Apr-23	80.47	58.05	66.81	61.55	69.96
May-23	85.68	63.83	78.34	69.16	76.98
Jun-23	89.67	67.16	83.40	72.81	81.05
Jul-23	96.41	73.41	89.67	80.18	87.16
Aug-23	98.43	72.84	91.54	79.20	88.71
Sep-23	82.94	63.37	77.14	68.88	75.13
Oct-23	76.56	56.88	69.82	61.63	68.69
Nov-23	71.98	57.17	64.44	59.89	65.53
Dec-23	70.99	63.27	66.02	64.41	67.24
Jan-24	74.68	60.72	69.46	63.93	69.02
Feb-24	76.95	61.24	66.30	63.04	69.75
Mar-24	78.36	50.54	55.09	52.33	64.10
Apr-24	83.69	52.78	60.02	55.30	69.18
May-24	85.79	61.23	75.14	66.34	75.54
Jun-24	90.94	67.51	84.57	74.33	81.71
Jul-24	97.66	72.42	90.82	79.18	87.92
Aug-24	100.99	75.13	93.92	82.03	91.00
Sep-24	89.93	67.38	83.64	73.88	81.01
Oct-24	76.18	57.20	69.57	61.41	68.72
Nov-24	73.18	58.32	66.09	61.42	66.64
Dec-24	74.05	60.80	68.57	63.85	68.46
Jan-25	79.23	61.37	70.48	64.72	71.58

ERCOT NORTH

Quote Date
2/8/2012

Forward Prices ($/MWh)
(Long term model includes capacity)

Forward Month	On Peak (5x16)	7x8	2x16	Wrap	7x24
Feb-25	78.23	61.96	67.15	63.84	70.70
Mar-25	78.21	50.66	55.22	52.45	64.10
Apr-25	82.96	59.88	68.09	62.73	72.62
May-25	86.88	69.98	79.25	69.97	77.61
Jun-25	92.52	68.33	86.04	74.97	83.16
Jul-25	100.33	73.00	93.31	80.46	89.86
Aug-25	103.73	76.09	96.47	84.08	92.95
Sep-25	90.95	68.06	84.58	74.26	82.05
Oct-25	77.31	55.27	67.21	59.33	68.22
Nov-25	73.88	57.95	66.02	61.35	66.63
Dec-25	74.50	65.10	69.29	66.64	70.36
Jan-26	82.40	65.45	76.63	69.44	75.29
Feb-26	80.98	64.06	69.42	66.01	73.14
Mar-26	82.79	53.61	58.23	55.31	68.33
Apr-26	86.77	61.99	70.49	64.95	75.61
May-26	91.21	67.77	84.74	74.81	81.87
Jun-26	97.43	71.96	90.61	78.45	87.73
Jul-26	105.34	77.34	97.96	84.36	94.74
Aug-26	108.63	79.46	101.02	87.92	97.27
Sep-26	94.03	71.22	87.45	77.31	85.11
Oct-26	83.09	62.38	76.51	67.54	74.90
Nov-26	80.50	60.69	68.77	63.91	71.28
Dec-26	79.24	67.68	73.70	69.89	74.31
Jan-27	83.80	65.92	76.64	70.37	76.15
Feb-27	83.08	63.20	68.50	65.13	73.68
Mar-27	85.92	51.98	56.26	53.44	69.53
Apr-27	89.51	58.42	66.44	61.21	75.05
May-27	94.27	67.39	84.26	74.39	82.94
Jun-27	100.92	73.55	93.85	80.61	90.54
Jul-27	108.71	79.59	101.10	88.03	97.37
Aug-27	111.53	81.06	103.73	89.38	99.86
Sep-27	95.09	74.61	88.44	79.79	86.93

USDA Rural Development
United States Department of Agriculture
Rural Development Utilities Programs - Data Collection System

HOME HELP LOGOUT CONTACT US

CLIFTON KARNEI : MY BORROWERS : BRAZOS ELECTRIC POWER COOPERATIVE, INC. [TX0121]

NAVIGATION

My DCS
- Borrowers
- Profile

My DCS Borrowers

My Borrowers : Brazos Electric Power Cooperative, Inc. [TX0121]

Financial and Operating Report Electric Power Supply - Filing Frequency: Annual

Year	Year-to-Date	Status	Audited Data	Action
2010	December	Submitted [04/08/2011 04:39 PM]	Yes	View Edit ASR BSP Export
2009	December	Submitted [04/12/2010 01:29 PM]	Yes	View Edit ASR BSP Export
2008	December	Submitted [04/02/2009 02:41 PM]	Yes	View Edit ASR BSP Export
2007	December	Submitted [04/18/2008 04:02 PM]	Yes	View Edit ASR BSP Export
2006	December	Submitted [04/09/2007 09:16 AM]	No	View Edit ASR BSP Export
2005	December	Submitted [03/16/2006 12:16 PM]	N/A	View Edit ASR BSP Export
2004	December	Submitted [03/14/2005 03:40 PM]	N/A	View Edit ASR BSP Export
2003	December	Submitted [03/12/2004 10:28 AM]	N/A	View Edit ASR BSP Export
2002	December	Submitted [04/08/2003 02:15 PM]	N/A	View Edit ASR BSP Export

New Power Supply Operating Report

Audit

Year	Approval-Date	File Name	Status	Action
No Audit File				

Upload Audit

Users associated with the borrower

Name	Phone Number	Phone Extension	Email	Title	Is Active?	Role(s)
Birkes, Kay	254-750-6250		kbirkes@brazoselectric.com	Treasury/Property/Risk Accounting Superv	Yes	User
Bordovsky, Khald	254-715-3014		kbordovsky@brazoselectric.com	VP Services	Yes	Administrator, User
Breton, Gina	254-749-0053		gbreton@brazoselectric.com	Accountant	Yes	User
Canada, Lois	254-750-6237		lcanada@brazoselectric.com	Secretary, VP Finance	Yes	User
Karnei, clifton	254-750-6500		ckarnei@brazoselectric.com	Exec VP & General Manager	Yes	Certifier, User
Krankolls, Timothy	254-750-6242		tkrankolls@brazoselectric.com	Accountant	Yes	User
Pankonien, Kelly	254-750-6238		kpankonien@brazoselectric.com	Accountant, Budget & Rates	Yes	User
perkins, wesley	254-750-6532		dperkins@brazoselectric.com	General Accounting Supervisor	Yes	User

Version 2.0.4108.17075

USDA United States Department of Agriculture
Rural Development Utilities Programs - Data Collection System

HOME HELP PRINT LOGOUT CONTACT US

CLIFTON KARNEI | BRAZOS ELECTRIC POWER COOPERATIVE, INC. (TX0121) | FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY | DECEMBER 2010

NAVIGATION

- Reports
  - Op. Report-Power Supply
    - Certification
    - Point Of Contact
    - Part a
      - Section A
      - Section B
      - Section C
    - Part b SE
    - Part b PP
    - Part c RE
    - Part e
    - Parts d-g
    - Part h
      - Section A
      - Section B
      - Section C
      - Section D
      - Section E
      - Section F
        - Sub Section I
        - Sub Section II
        - Sub Section III
        - Sub Section IV
      - Section G
      - Section H
      - Section I
      - Section J
      - Section K
      - Section L
    - Part i
      - Section A
      - Section B
      - Section C
      - Section D

Certification

Certification saved successfully.

This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C 552).

According to the Paperwork Reduction Act of 1995, an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The valid OMB control number for this information collection is 0572-0032. The time required to complete this information collection is estimated to average 25 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES

DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7CFR CHAPTER XVII
(check one of the following)

- (●) All of the obligations under the RUS loan documents have been fulfilled in all material respects.
- ( ) There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part a Section C of this report.

- (●) Share this data with NRUCFC.
- ( ) Do not share this data with NRUCFC.

Manager Name: Clifton Karnei
Manager Title: Exec VP & General Mana
Date Certified and Electronically Signed: 4/6/2011

(●) Certify ( ) Uncertify

Save

Version 2.0.4106.17076

(Rev. 12-06)

USDA Rural Development

United States Department of Agriculture
Rural Development Utilities Programs - Data Collection System

HOME HELP PRINT LOGOUT CONTACT US

CLIFTON KARNEI | BRAZOS ELECTRIC POWER COOPERATIVE, INC. [TX0121] | FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY / DECEMBER 2010

NAVIGATION

- Reports
  - Op. Report-Power Supply
    - Certification
    - Point Of Contact
    - Part a
      - Section A
      - Section B
      - Section C
    - Part b SE
    - Part b PP
    - Part c RE
    - Part e
    - Parts d-g
    - Part h
      - Section A
      - Section B
      - Section C
      - Section D
      - Section E
      - Section F
        - Sub Section I
        - Sub Section II
        - Sub Section III
        - Sub Section IV
      - Section G
      - Section H
      - Section I
      - Section J
      - Section K
      - Section L
    - Part i
      - Section A
      - Section B
      - Section C
      - Section D

Certification

This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C 552).

According to the Paperwork Reduction Act of 1995, an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The valid OMB control number for this information collection is 0572-0032. The time required to complete this information collection is estimated to average 25 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES

DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7CFR CHAPTER XVII
(check one of the following)

- (●) All of the obligations under the RUS loan documents have been fulfilled in all material respects.
- ( ) There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part a Section C of this report.

- (●) Share this data with NRUCFC.
- ( ) Do not share this data with NRUCFC.

Manager Name: clifton karnei
Manager Title: Exec VP & General Mana
Date Certified and Electronically Signed: 4/6/2011

(●) Certify ( ) Uncertify

Save

Version 2.0.4106.17076

(Rev. 12-06)

According to the Paperwork Reduction Act of 1995, an agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid OMB control number. The valid OMB control number for this information collection is 0572-0032. The time required to complete this information collection is estimated to average 21 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information.

UNITED STATES DEPARTMENT OF AGRICULTURE RURAL UTILITIES SERVICE	BORROWER DESIGNATION TX0121
FINANCIAL AND OPERATING REPORT ELECTRIC POWER SUPPLY	PERIOD ENDED December, 2010 (Prepared with Audited Dat
	BORROWER NAME Brazos Electric Power Cooperative, Inc.

INSTRUCTIONS - See help in the online application.

This information is analyzed and used to determine the submitter's financial situation and feasibility for loans and guarantees. You are required by contract and applicable regulations to provide the information. The information provided is subject to the Freedom of Information Act (5 U.S.C. 552)

CERTIFICATION

We recognize that statements contained herein concern a matter within the jurisdiction of an agency of the United States and the making of a false, fictitious or fraudulent statement may render the maker subject to prosecution under Title 18, United States Code Section 1001.

We hereby certify that the entries in this report are in accordance with the accounts and other records of the system and reflect the status of the system to the best of our knowledge and belief.

ALL INSURANCE REQUIRED BY PART 1788 OF 7 CFR CHAPTER XVII, RUS, WAS IN FORCE DURING THE REPORTING PERIOD AND RENEWALS HAVE BEEN OBTAINED FOR ALL POLICIES DURING THE PERIOD COVERED BY THIS REPORT PURSUANT TO PART 1718 OF 7 CFR CHAPTER XVII

(check one of the following)

[X] All of the obligations under the RUS loan documents have been fulfilled in all material respects.

[ ] There has been a default in the fulfillment of the obligations under the RUS loan documents. Said default(s) is/are specifically described in Part A Section C of this report.

clifton karnei

4/6/2011
DATE

UNITED STATES DEPARTMENT OF AGRICULTURE
RURAL UTILITIES SERVICE

FINANCIAL AND OPERATING REPORT
ELECTRIC POWER SUPPLY
PART F CC - COMBINED CYCLE PLANT

BORROWER DESIGNATION TX0121

PLANT Johnson County

PERIOD ENDED December, 2010

INSTRUCTIONS - See help in the online application.

SECTION A. COMBINED CYCLE GENERATING UNITS

NO. (a)	UNIT NO. (a)	SIZE (KW) (b)	FUEL CONSUMPTION: OIL (1000 Gals.) (c)	GAS (1000 CF) (d)	OTHER (e)	TOTAL (f)	OPERATING HOURS: IN SERVICE (g)	ON STANDBY (h)	OUT OF SERVICE: SCHED. (i)	UNSC. (j)	GROSS GENER. (MWh) (k)	BTU PER kWh (l)
1.	1	172,000	0.00	7,437,976.00	0.00		7,606	323	873	158	974,427	
2.	2	86,000	0.00	3,718,986.00	0.00		7,606	123	873	158	487,215	
3.												
4.												
5.												
6.	Total	258,000	0.00	11,156,962.00	0.00		15,212	446	1,746	316	1,461,642	7,636.34
7.	Average BTU		0.00	994.32			Station Service (MWh)				30,313.00	
8.	Total BTU (10^9)		0.00	11,091,433.00		11,091,433.00	Net Generation (MWh)				1,428,325.00	7,761.66
9.	Total Del. Cost ($)		0.00	0.00	0.00		Station Service % Of Gross				2.48	

SECTION B. LABOR REPORT

NO.	ITEM	VALUE	NO.	ITEM	VALUE
1.	No. Employees Full Time (Include. Superintendent)	1	5.	Maintenance Plant Payroll ($)	0
2.	No. Employees Part Time	0	6.	Other Accounts Plant Payroll ($)	0
3.	Total Employee Hours Worked	0	7.	Total Plant Payroll ($)	148232
4.	Operating Plant Payroll ($)	148232			

SECTION C. FACTORS & MAXIMUM DEMAND

NO.	ITEM	VALUE
1.	Load Factor (%)	64.40%
2.	Plant Factor (%)	64.67%
3.	Running Plant Capacity Factor (%)	74.46%
4.	15 Min. Gross Max. Demand (kW)	
5.	Indicated Gross Max. Demand (kW)	259,083

SECTION D. COST OF NET ENERGY GENERATED

NO.	PRODUCTION EXPENSE	ACCOUNT NUMBER	AMOUNT ($) (a)	MILLS/NET kWh (b)	$/10^9 BTU (c)
1.	Operation, Supervision and Engineering	500	223,009		
2.	Fuel, Oil	547.1	0		
3.	Fuel, Gas	547.2	49,610,121		4.47
4.	Fuel, Other	547.3	0		
5.	Energy for Compressed Air	547.4	0	0.00	
6.	Fuel SubTotal (2 thru 5)	547	49,610,121	34.80	4.47
7.	Generation Expenses	548	169,016		
8.	Miscellaneous Other Power Generation Expenses	549	1,313,249		
9.	Rents	507	0		
10.	Steam Expenses	502	526,271		
11.	Electric Expenses	505	0		
12.	Miscellaneous Steam Power Expenses	506	2,510,669		
13.	Allowances	509	0		
14.	Non-Fuel SubTotal (1 + 7 thru 13)		4,750,205	3.33	
15.	Operating Expense (6 + 14)		54,360,326	38.13	
16.	Maintenance, Supervision and Engineering	551,510	0		
17.	Maintenance of Structures	552,511	6,358		
18.	Maintenance of Generating and Electric Plant	553,513	6,126,060		
19.	Maintenance of Miscellaneous Other Power Generating Plant	554,514	70,111		
20.	Maintenance Expense (16 thru 19)		6,200,529	4.35	
21.	Total Production Expense (15 + 20)		60,560,855	42.48	
22.	Depreciation	403.4, 403.1, 411.10	6,505,989		
23.	Interest	427	14,000,732		
24.	Total Fixed Cost (22 + 23)		20,506,321	14.38	
25.	Power Cost (21 + 24)		81,067,176	56.87	

Remarks

	Jack 1 STG Weighted Avg. Gas (MMBtu)	Value Without Transportation	Average Monthly Cost	Heat Rate	Value With Transportation	Johnson STG Weighted Avg. Gas (MMBtu)	Value Without Transportation	Value With Transportation
Jan-09	958,361	$ 4,573,320.31	$ 34.39	7.19	$ 4,677,563.71	324,379	$ 1,551,181.78	$ 1,586,539.13
Feb-09	843,819	$ 2,892,612.77	$ 24.46	7.13	$ 3,019,185.57	234,291	$ 803,149.47	$ 838,293.12
Mar-09	912,676	$ 2,757,192.93	$ 21.60	7.15	$ 2,888,618.21	-	$ -	$ -
Apr-09	220,030	$ 733,578.69	$ 22.63	6.79	$ 785,725.70	-	$ -	$ -
May-09	801,279	$ 2,403,034.28	$ 21.95	7.32	$ 2,513,610.72	199,381	$ 697,882.50	$ 625,394.26
Jun-09	1,047,398	$ 3,280,925.77	$ 22.66	7.21	$ 3,416,613.58	395,940	$ 1,244,042.86	$ 1,291,555.64
Jul-09	1,175,097	$ 4,044,682.36	$ 24.92	7.24	$ 4,184,518.85	436,267	$ 1,501,629.80	$ 1,553,545.53
Aug-09	1,170,960	$ 3,807,962.31	$ 23.86	7.28	$ 3,944,964.64	398,942	$ 1,297,359.56	$ 1,344,035.78
Sep-09	955,927	$ 2,470,115.73	$ 18.94	7.33	$ 2,586,738.84	356,756	$ 921,857.94	$ 965,382.19
Oct-09	645,815	$ 2,330,745.61	$ 25.63	7.10	$ 2,420,513.87	327,944	$ 1,183,190.13	$ 1,228,780.49
Nov-09	395,283	$ 1,557,810.30	$ 29.89	7.58	$ 1,623,822.56	302,661	$ 1,192,786.42	$ 1,243,330.78
Dec-09	935,970	$ 4,272,703.69	$ 33.11	7.25	$ 4,586,763.98	287,754	$ 1,313,641.07	$ 1,349,323.76
Jan-10	890,560	$ 5,183,057.86	$ 41.51	7.13	$ 5,299,721.19	330,752	$ 1,924,977.40	$ 1,968,305.93
Feb-10	791,756	$ 4,259,645.13	$ 38.16	7.09	$ 4,364,156.87	312,599	$ 1,681,783.75	$ 1,723,046.84
Mar-10	224,813	$ 1,002,888.83	$ 33.31	7.47	$ 1,051,448.34	302,377	$ 1,348,902.23	$ 1,414,215.58
Apr-10	742,624	$ 2,823,456.37	$ 27.76	7.30	$ 2,935,592.59	84,561	$ 321,501.36	$ 334,270.06
May-10	750,748	$ 3,030,769.95	$ 29.64	7.34	$ 3,139,628.42	183,830	$ 742,123.18	$ 768,778.58
Jun-10	1,084,434	$ 4,477,628.48	$ 30.15	7.30	$ 4,618,604.92	400,855	$ 1,655,132.00	$ 1,707,245.20
Jul-10	1,063,612	$ 4,856,453.31	$ 37.33	8.18	$ 4,977,705.10	433,624	$ 1,979,925.29	$ 2,029,358.38
Aug-10	1,217,747	$ 5,148,533.47	$ 30.46	7.20	$ 5,299,634.07	495,894	$ 2,096,541.60	$ 2,158,132.50
Sep-10	968,276	$ 3,479,015.60	$ 26.74	7.44	$ 3,595,208.71	416,970	$ 1,498,174.88	$ 1,548,211.34
Oct-10	284,801	$ 1,041,354.38	$ 26.65	7.26	$ 1,095,713.08	374,872	$ 1,371,658.02	$ 1,443,258.64
Nov-10	702,850	$ 2,274,423.51	$ 22.60	7.05	$ 2,367,902.69	314,649	$ 1,018,205.60	$ 1,060,053.97
Dec-10	716,364	$ 2,938,527.10	$ 29.27	7.14	$ 3,030,221.75	320,868	$ 1,316,202.38	$ 1,357,273.55
Jan-11	786,032	$ 3,171,827.43	$ 29.00	7.21	$ 3,272,695.48	311,764	$ 1,254,851.06	$ 1,294,756.88
Feb-11	799,836	$ 3,528,076.60	$ 31.71	7.19	$ 3,641,653.31	300,991	$ 1,327,670.33	$ 1,370,411.02
Mar-11	304,272	$ 1,143,151.52	$ 29.28	7.79	$ 1,217,089.72	312,348	$ 1,173,493.21	$ 1,249,393.89
Apr-11	841,645	$ 3,514,709.13	$ 30.22	7.24	$ 3,609,815.00	103,956	$ 434,120.34	$ 445,867.37
May-11	930,809	$ 3,937,320.32	$ 31.38	7.42	$ 4,044,363.31	267,952	$ 1,133,436.75	$ 1,164,251.22
Jun-11	1,102,253	$ 4,757,322.74	$ 34.52	8.00	$ 4,910,535.86	317,458	$ 1,370,149.07	$ 1,414,275.75
Jul-11	1,119,881	$ 4,808,769.07	$ 30.32	7.06	$ 4,985,710.27	336,406	$ 1,444,529.08	$ 1,497,681.29
Aug-11	916,276	$ 3,848,359.69	$ 30.60	7.29	$ 3,983,965.56	446,780	$ 1,876,476.25	$ 1,942,599.70
Sep-11	910,576	$ 3,554,888.86	$ 28.28	7.24	$ 3,707,865.63	298,117	$ 1,166,039.01	$ 1,205,786.59
Oct-11	161,561	$ 583,756.80	$ 26.26	7.27	$ 623,202.01	290,800	$ 1,050,077.36	$ 1,121,032.46
Nov-11	770,091	$ 2,552,081.67	$ 23.95	7.23	$ 2,703,019.51	305,564	$ 1,012,638.53	$ 1,072,528.04
Dec-11	797,476	$ 2,804,556.47	$ 23.51	7.20	$ 2,743,317.29	106,068	$ 346,416.52	$ 364,872.27
	28,941,806				$ 117,669,414	10,632,261		$ 43,681,767
					4.07			4.11

Johnson County, Steam Output Revenue/Cost Stream

	Period Energy	Period Revenue	Revenue 36 month avg	Expense	mmBTU/mwh	Avg $/mmBTU	Expense 36 month avg
Jan 2009 - Dec 2011	1,349,799	$ 60,034,499	$ 44.48	$ 42,141,847	7.88	$ 3.96	$ 31.22

Jack County 1, Steam Output Revenue/Cost Stream

	Period Energy	Period Revenue	Revenue 36 month avg	Expense	mmBTU/mwh	Avg $/mmBTU	Expense 36 month avg
Jan 2009 - Dec 2011	3,968,191	$ 166,363,269	$ 41.92	$ 113,655,359	7.29	$ 3.93	$ 28.64

Notes:
[1] Steam Energy based on monthly EIA Reports
[2] Revenue calculations based on SCADA extracts reconciled to EIA Reports
[3] Cost stream calculations based on EIA information w/ allocation of MMBTU based on ratio of steam energy output to total plant output

Bryan W. Shaw, Ph.D., P.E., *Chairman*
Toby Baker, *Commissioner*
Zak Covar, *Commissioner*
Richard A. Hyde, P.E., *Executive Director*

JUN 13 2014

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

June 5, 2014

Mr. J. M. Harris
Agent
H & H Associates
406 FM 3016
Grapeland, Texas 75844

Re: Notice of Negative Use Determination
Brazos Electric Power Cooperative, Inc.
Johnson County Generation Facility
Cleburne (Johnson County)
Regulated Entity Number: RN100221985
Customer Reference Number: CN600128821
Application Number: 13544

Dear Mr. Harris:

This letter responds to Brazos Electric Power Cooperative, Inc.'s Application for Use Determination for Johnson County Generation Facility, originally submitted on April 27, 2009 and remanded to the executive director (ED) on December 5, 2012 by the Texas Commission on Environmental Quality (TCEQ) commissioners. Your Tier IV partial use determination application seeks a use determination for one Heat Recovery Steam Generator (HRSG) and dedicated ancillary systems.

The ED has completed the review for application #13544 and the associated notice of deficiency (NOD) responses and has issued a Negative Use Determination for the property in accordance with Title 30 Texas Administrative Code (TAC) Chapter 17. The Negative Use Determination is issued because the methods for determining the use determination percentage were not reasonable.

The Tier IV application process, in place in commission rules between February 2008 and December 2010, allowed an applicant to propose a method for calculating a partial use determination. The commission rules allow for determinations that distinguish the proportion of property that is used to control, monitor, prevent, or reduce pollution from the proportion of property that is used to produce goods or services. If the property is not used wholly for the control of air, water, or land pollution, the applicant must present information in the application for the determination of the proportion of the property that is pollution control. It is the responsibility of the applicant to propose a reasonable method for determining the use determination percentage. It is the responsibility of the ED to review the proposed method and make the final determination.

After careful review of the five methods for calculating a partial positive use determination included in the applicant's submittals, the ED has determined that all but one of the methods are unacceptable. The four methods proposed by the applicant do not reasonably distinguish the proportion of the HRSG and dedicated ancillary systems that provides a purported pollution control benefit from the proportion of the HRSG and dedicated ancillary systems that produces steam that is used in a process or to produce electricity for use or sale. The one method that the ED does find acceptable, the Cost Analysis Procedure (CAP) adopted by the commission, produces a negative number. Therefore, the property is not eligible for a positive use determination.

The following is an explanation of the ED's review of the methodologies presented in your application:

- Executive Director's December 3, 2008 Brief (61%): Subsequent to filing the brief where this methodology is presented, the ED determined that the proposed calculation did not accurately calculate an appropriate use determination because the less efficient the equipment, the higher the positive use determination percentage it yielded. This produces an unreasonable result and should not provide the basis for a final determination.

- Avoided Emissions Approach (40%): This approach is not reasonable because it does not distinguish the proportion of property used to control or prevent pollution from the proportion used to produce a product. Furthermore, the avoided emission approach does not attribute any value to production. By attributing the entire avoided emissions to the HRSG and dedicated ancillary systems, this approach ignores nitrogen oxides (NOx) reductions related to other property for which a positive use determination has been issued.

- Modified CAP Calculation (64%): Capital Cost New (CCN) includes dedicated ancillary systems. Allowing Capital Cost Old (CCO) to be equal a pipe or spool piece ignores that HRSGs are alternative production equipment. CCO is the cost of comparable equipment without the pollution control. If the HRSGs produce steam, then comparable equipment that produces steam without pollution control is a boiler. The ED does not find it reasonable to equate CCO to a spool piece.

- Modified CAP Calculation (100%): Capital Cost New (CCN) includes dedicated ancillary systems. Allowing Capital Cost Old (CCO) to be $0 ignores that HRSGs are alternative production equipment. CCO is the cost of comparable equipment without the pollution control. If the HRSGs produce steam, then comparable equipment that produces steam without pollution control is a boiler. The ED does not find it reasonable to attribute $0 cost to CCO in the CAP.

- CAP as proposed by the executive director (-83%): The CAP formula was adopted by the commission to provide a methodology for determinations that distinguishes the proportion of property that is used to control, monitor, prevent, or reduce pollution from the proportion of property that is used to produce goods

or services. The fact that the CAP calculated results in a negative number shows that the HRSGs' and dedicated ancillary equipment's pollution prevention benefit is negated by its ability to produce a product.

Please be advised that a Negative Use Determination may be appealed. The appeal must be filed with the TCEQ Chief Clerk within 20 days after the receipt of this letter in accordance with 30 TAC §17.25.

If you have questions regarding this letter or need further assistance, please contact Ronald Hatlett of the Tax Relief for Pollution Control Property Program by telephone at (512) 239-6348, by e-mail at ronald.hatlett@tceq.texas.gov, or write to the Texas Commission on Environmental Quality, Tax Relief for Pollution Control Property Program, MC-110, P.O. Box 13087, Austin, Texas 78711-3087.

Sincerely,

David Brymer, Director
Air Quality Division

DB/rh

cc: Chief Appraiser, Johnson County Appraisal District, 109 N. Main St., Cleburne, Texas, 76033-4941