ATMOSPHERIC DYNAMICS
METEOROLOGICAL AND AIR QUALITY MODELING

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April 18, 2010

Ms. Shirley Rivera
EPA Region 9
75 Hawthorne St.
Air Permits Office (AIR-3)
San Francisco, CA. 94105

Re: Blythe Energy Project Phase II Permit Application Addendum

Dear Shirley:

Caithness Blythe II, LLC had previously submitted a Prevention of Significant Deterioration (PSD) Permit application to modify the existing Blythe Phase II Project. The modification to the existing project will be able to generate a nominal 520 MW of electric power and will be located within the City of Blythe. The project is also located adjacent to the existing Blythe Energy Project (BEP I). BEP I is currently owned and operated by FPL Energy. The application was submitted in November, 2009.

As per our discussions with you and your staff, please find the enclosed permit addendums covering the following areas:

- Top-down BACT
- Cooling technology BACT
- CO ppm revision to 2 ppm
- AQ modeling - 1-hr NO_2 and PM2.5

As you know, the Mojave Desert Air Quality Management District (MDAQMD) has recently issued the Preliminary Determination of Compliance (PDOC). We are seeking a completeness determination from Region 9 for this project and believe that providing this additional data will satisfy this requirement.

Thank you for your attention in this matter. If you have any questions with regards to the application, please contact Gregory Darvin at (805) 569-6555 or Richard Booth at (530) 474-1893.

Sincerely,
Atmospheric Dynamics, Inc.

Gregory S. Darvin

BLYTHE II PSD PERMIT ADDENDUM

CAITHNESS BLYTHE II –BLYTHE ENERGY PROJECT PHASE II GENERATING STATION-AUXILIARY BOILER, COMBINED CYCLE COMBUSTION TURBINE, AND COOLING TOWER BACT ANALYSIS

April 2010

Section 1 - BACT Analysis Methods and Assumptions

Background

In general, California New Source Review Regulations require a control technology that has been achieved in practice for a class or category of source be required as BACT/LAER for sources in that class or category without considering case-by-case economic impact. (Note: In some cases, economic considerations may be taken into account in establishing a class or category of source.) Additionally, many air districts require other more effective technologies that have not been achieved in practice for a class or category of source if the control is shown to be technologically and economically feasible.

Unlike federal BACT/LAER that only apply to major sources, California requirements apply to a great variety of small and large sources. Therefore, clear identification of the sources that are included in a given class or category for which a BACT/LAER determination is being or has been made is critical to reasonable implementation of BACT/LAER requirements in California. Additionally, it is vitally important to ascertain the availability, reliability, and effectiveness of a control technology before deeming it as having been achieved in practice for a class or category of sources.

Top-Down BACT Assessment

EPA recommends using a "top-down" approach for determining BACT and LAER. This approach essentially ranks potential control technologies in order of effectiveness and ensures that the best technically and economically feasible option is chosen. As described in EPA's *New Source Review Workshop Manual*, draft, October 1990, the general methodology of this approach is as follows:

1. Identify potential control technologies, including combinations of control technologies, for each pollutant subject to NSR-PSD review. The control technologies identified should include; inherently lower-emitting processes/practices, add-on controls, or a combination of the two.
2. Evaluate each control technology for technical feasibility; eliminate those determined to be technically infeasible.
3. Rank the remaining technically feasible control technologies in order of control effectiveness.
4. Assume the highest-ranking technically feasible control represents BACT/LAER, unless it can be shown to result in adverse environmental, energy, or economic impacts. LAER determinations do not typically include an economic impact evaluation. (Economic impacts, i.e., total cost effectiveness or incremental cost effectiveness, are only required for the technically feasible control technologies.) However, an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. If the applicant accepts, or selects, the top alternatives in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts inother media would justify selection of an alternative control option. If no such issues are identifed, the analysis is ended and the results are proposed as BACT.
5. Select BACT/LAER.

EPA and State maintained RACT/BACT/LAER Clearinghouses (RBLCs) are considered as principal references for identifying potential control technologies and emission rates used in past permitting of similar sources. These databases were queried for entries since January 2000 involving combustion turbines, auxiliary boilers, and evaproative condensers. The emission rates proposed are consistent with the entries in the various State and EPA databases for past (post-2000) BACT/LAER evaluations, especially those for sources with similar MMBtu/hr and MW ratings.

Additionally, CARB guidance recommends that the following criteria should be used in determining whether an emissions unit belongs to a class or category of source for which a control technology has been achieved in practice:

A. Source Size (e.g., rating or capacity): The degree of needed similarity may vary based on the equipment type and size. In general, size thresholds that signify a change in emission producing characteristics of the equipment provide for a reasonable delineation based on size. Generally accepted size designations (e.g., small, medium, and large) for a piece of equipment may also be used in defining a class or category of source. It should be noted that EPA does not consider size in defining a class or category of source.

B. Capacity Factor: Limited use, standby, or seasonal equipment are not usually lumped together with full time equipment in a single class or category.

C. Unique Operational/Technological Issues: Certain operational needs and characteristics can impact the effectiveness of a control technology or process.

Operational or technological needs with demonstrable impact on effectiveness or reliability of basic equipment, operation, process, or control technology that are essential to successful operation of an emission unit and cannot be overcome by other reasonable measures can be used in defining a class or category of source. Also, in certain situations, available pre-existing resources at a facility play a key role in rendering certain control technologies feasible. Requiring similar controls at facilities that do not have the same existing resources may not be advisable.

It should be noted that different BACT/LAER control levels may be established within the same class and category of source for varying operational modes. For instance, for gas turbines BACT/LAER levels during startup/shutdown conditions may differ from BACT/LAER levels under full load conditions.

Achieved in Practice Determinations

For an emission or performance level to be achieved in practice for a class or category of source, it should be commercially available, have demonstrated reliability of operation, and have a documented effectiveness verified by acceptable forms of emission or performance measurement.

A. Commercial Availability: At least one vendor should offer the control technology or equipment able to reach an achieved-in-practice emission limit or performance requirement for regular or full-scale operation within the United States. (On the federal level, determinations made outside of the US should also be considered. These considerations, in some instances, can be very difficult to include due to the lack of an organized clearinghouse for compilation of data.)

B. Reliability in Operation: The control technology or equipment should have operated for a reasonable time period in a manner that would provide an expectation of continued reliability. It is not necessary that the equipment operation be continuous, but that the equipment operate reliably in a manner typical of the class or category of source.

C. Effectiveness: The control technology or equipment should be verified to perform effectively over the range of operation expected for the class or category of source. If the control technology or equipment will be allowed to operate at lesser effectiveness during certain modes of operation, then those modes of operation must be identified. The verification should be based on a performance test or tests, when possible, or other performance data.

Any control technology listed in a permitting agency's BACT/LAER Clearinghouse must be considered in establishing BACT/LAER requirements for that class or category of source. However, prior to accepting another agency's BACT/LAER determination as having been achieved in practice for a class and category, the permitting agency should verify that the technology has been achieved in practice in accordance with the above guidelines. Existing information should be used to the extent needed to prove that the technology has been achieved in practice.

Technology Transfer

Control technologies previously achieved in practice for a class and category of sources and/or other technologically feasible controls should be considered for transfer to other class or category of sources. Potentially transferable control technologies may be either add-on exhaust stream controls, or process controls and modifications. For the first type, technology transfer should be considered between sources that produce similar exhaust streams. For the second type, technology transfer should be considered between sources with similar processes.

The “top-down” procedure is generally followed for the BACT/LAER analyses for the pollutants evaluated in this analysis, with a focus on identifying emission limitations or control technologies that are achieved in practice and technically feasible. The following sections present the BACT/LAER analyses and proposed NO_x, CO, PM_{10}, VOC, and SO_2 limits and controls.

Section 2 - BACT Analysis for the Auxiliary Boiler

The proposed auxiliary boiler at the BEPII facility is described as follows:

Boiler Parameter	**Parameter Rating**
Fuel	Natural Gas
Heat Rating	60 mmbtu/hr
Maximum daily hours of operation	24
Maximum annual hours of operation	2500
Proposed NOx Controls	Low NOx Burners, 9 ppmvd
Proposed CO Controls	GCP, 50 ppmvd
Proposed VOC (POC) Controls	GCP, 5 ppmvd
Proposed $PM_{10/2.5}$ and SOx Controls	Natural Gas/Clean Fuel
$PM_{10/2.5}$ Emission Rate	0.0045 lbs/mmbtu (HHV)

The proposed auxiliary boiler emissions as presently quantified are as follows (based on the above ratings and operations data):

Pollutant	**Lbs/hr**	**Lbs/day**	**Tons/yr**
NOx	0.55	13.2	0.688
CO	1.85	44.4	2.32
VOC	0.11	2.64	0.138
SOx	0.14	3.37	0.176
$PM_{10/2.5}$	0.27	6.48	0.337

The table below presents the BACT proposal for the auxiliary boiler based upon the data presented in this analysis.

BACT Pollutant	**BACT Limit**	**Proposed BACT System**
NOx	9 ppmvd	Low NOx Burners
CO	50 ppmvd	Good Combustion Practices (GCP)
VOC	5 ppmvd	GCP, Sole use of PUC Grade Natural Gas
SOx	0.00233 lb/mmbtu	Sole use of PUC Grade Natural Gas
$PM_{10/2.5}$	0.0045 lb/mmbtu	Sole use of PUC Grade Natural Gas

A summary of BACT determinations or BACT requirements for similar sized boilers as derived from several of California’s air districts and the EPA RBLC database are presented below.

Agency	Size Range, mmbtu/hr	NOx BACT	CO BACT	VOC BACT	SOx BACT	PM10/2.5 BACT	Comments
BAAQMD	33.5 - 50	9 – 25 ppm	100 ppm	GCP	Nat Gas	Nat Gas	NOx 9 ppm TFCE NOx 25 ppm AiP
	>50	7 – 9 ppm	10 – 50 ppm	GCP	Nat Gas	Nat Gas	NOx 7 ppm TFCE NOx 9 ppm AiP
SDAPCD	<50	12 ppm	ND	Nat Gas	Nat Gas	Nat Gas	PM 0.10 gr/dscf
	50 - 250	5-9 ppm	ND	Nat Gas	Nat Gas	Nat Gas	PM 0.10 gr/dscf
SCAQMD	<50	7 – 9 ppm	50 – 100 ppm	3 ppm	Nat Gas	Nat Gas	
	50 - 100	9 ppm	100-400 ppm	Nat Gas	Nat Gas	Nat Gas	
SJVUAPCD	<100	9 – 30 ppm	<400 ppm	.003 lb/mmbtu	Nat Gas	Nat Gas	
	100-200	9 – 15 ppm	ND	Nat Gas	Nat Gas	Nat Gas	
EPA RBLC*	20 - 100	9 – 300 ppm	10 – 400 ppm	0.02 – 0.002 lb/mmbtu	Nat Gas	Nat Gas	9 ppm NOx TFCE 9 ppm NOx AiP

ppm = values at at 3% O2 (dry) unless otherwise stated
TFCE = technologically feasible/cost effective
AiP = achived in practice
GCP = good combustion practices
ND = not determined or no data
*RBLC search criteria (boilers only, firing natural gas, 20-100 mmbtu hr, Process code 13.310, variable use rates). File supplied in HTM format.

Analysis of Control Requirements for Nitrogen Oxides

Identify Potential Control Technologies

The baseline NO_x emission rate for this analysis is considered to be 0.10 lb/MMBtu for the boiler, based on the applicable New Source Performance Standards (40 CFR Part 60, Subpart Db). It should be noted that the proposed aux boiler is actually a Subpart Dc unit, but Subpart Dc does not specify NOx (or other pollutant) emission rates for natural gas fired units. The Subpart Db emission rate provides a comparison for the evaluation of control effectiveness and feasibility. The maximum degree of control, which results in the lowest NO_x emission rate, is a combination of low-NO_x burners (LNB) in conjunction with selective catalytic reduction (SCR). Note that as an auxiliary boiler, the operation of the boiler will be limited to 2500 hours/year.

As with other combustion sources, NO_x emissions from boilers can be reduced by combustion controls and post-combustion flue gas treatment. Combustion controls include low-NO_x burners and other combustion modifications, which act to reduce the formation of NO_x during the combustion process. Post-combustion controls remove NO_x from the exhaust stream after it is generated. Potential NO_x control technologies for the boiler include the following:

- Low-NO_x burners (LNB)
- Flue gas recirculation (FGR)
- LNB and FGR
- SCONO$_x$
- Selective catalytic reduction (SCR)
- Selective non-catalytic reduction (SNCR)

Evaluate Control Technologies for Technical Feasibility

The performance and technical feasibility of the NO_x controls listed above are discussed separately. Combustion controls are discussed first, and a discussion of the post-combustion controls SCR and SNCR follows. The proposed boiler will be fired with only natural gas and be well-maintained and operated with good combustion practices, thus these control options are not discussed separately below.

- **Low-NO_x Burners (including Ultra Low-NOx Burners)**

Low-NO_x burners (LNB) and ULNBs have been developed over the last few decades by applying combustion modifications to "conventional" burners. Low-NO_x burners are very common and there are many variations available from numerous manufacturers. A LNB is a packaged assembly that uses staged combustion techniques to reduce the formation of thermal NO_x. The purposes of LNB are to reduce the amount of oxygen in critical NO_x formation zones, to modify the introduction of air and fuel so that the rate of mixing is slowed, and to reduce the amount of fuel burned at the peak flame temperature. There are two basic types of LNB, air-stage and fuel-staged. Both types of LNB achieve the above objectives, thus, emissions are reduced when compared with conventional burners.

- **Flue Gas Recirculation**

As the name implies, with FGR a portion of the flue gas is recirculated and mixed with the combustion air supply. For new boiler installations, this is usually accomplished with a larger forced draft fan, as compared to that required without FGR. The objective of FGR is to lower the amount of oxygen available to react with nitrogen and reduce the flame temperature, both of which reduce the formation of NO_x. One drawback to FGR is that efficiency is somewhat reduced due to the additional power requirements of the larger fan. The addition of FGR to a LNB assembly can result in further reductions in thermal NO_x formation.

- **$SCONO_x$ for Boilers**

$SCONO_x$ for boilers, as with $SCONO_x$ for turbines, involves a catalyst system initially produced and marketed by Goal Line Environmental Technologies. Other suppliers and marketers are now supposedly offering the technology. In early 2000, the South Coast AQMD BACT database listed an entry in its BACT determinations for "other technologies" (i.e., those that do not qualify as LAER) from April 2000 for $SCONO_x$ applied to a 4.2 MMBtu/hr boiler at a facility within the SCAQMD. No such listing could be found in the SCAQMD BACT database during this analysis, and the applicant could not find any listings for a SCONOx application on any small auxiliary type boilers.

Data compiled by the Energy Solutions Center (DG Consortium, 2004) indicates the following; "the SCONOX system is a new catalytic reduction technology that has been developed and is currently being made available for natural gas-fired turbines. It is based on a unique integration of catalytic oxidation and absorption technology. CO and NO are catalytically oxidized to CO2 and NO2. The NO2 molecules are subsequently absorbed on the treated surface of the SCONOX catalyst. The system manufacturer, EmerChem, guarantees CO emissions of 1 ppm and NOx emissions of 2 ppm. The SCONOX system does not require the use of ammonia, eliminating the potential of ammonia slip conditions evident in existing SCR systems. Only limited emissions data were available for a gas turbine equipped with a SCONOX system. This data reflected HAP emissions and was not sufficient to verify the manufacturer's claims."

EmeraChem, which is a supplier and licenser of the EMx (SCONOX) technology claims on its website that "EMx is a multi-pollutant technology that significantly reduces NOx, SOx, CO, VOC, and PM for gas-fired turbines to ultra low levels (< 1 ppm for all criteria pollutants). The next generation of SCONOx is a multi-pollutant technology in a single system that significantly reduces NOx, SOx, CO, VOC, and PM for air emission requirements. The U.S. EPA declared this technology "the Lowest Achievable Emission Rate" (LAER) for NOx abatement, establishing the standard against which all future emission reduction means will be measured. EMx is the most effective Ammonia Free Reduction (AFR) technology available today for gas turbine (GT), reciprocating engines (IC), and industrial/utility boilers (IB)." To date, the applicant does not believe that any of these claims have been substantiated. The EmeraChem website is replete with such statements, but lacks any actual technology application data, results, operational histories, etc. In addition, the EmeraChem website clearly states that the application of EMx (SCONOx) on commercial/industrial boilers is a <u>future application</u>. Furthermore, they state that a "pilot" unit showed emissions reductions on the order of 95%. Based upon our understanding of the current BACT guidelines, a pilot unit does not establish "achieved in practice".

In the above sections of this analysis a discussion was presented of the criteria used for determining whether a control is achieved in practice. Commercial availability for boiler applications requires that a commercial guarantee is available from the vendor. Given that this technology <u>may</u> have only been applied to one source (which cannot at this time be confirmed), the availability of a commercial guarantee for a much larger boiler is seriously in question. Also, the reliability of $SCONO_x$ on a larger boiler has not been demonstrated. Thus, sufficient data to evaluate the reliability of $SCONO_x$ has not been generated. Also, the effectiveness of $SCONO_x$ on a large boiler has not been demonstrated. As a result of these factors, this control is not considered technically feasible for the proposed boiler.

- **Selective Catalytic Reduction**

Selective catalytic reduction is a post-combustion flue gas treatment in which NO_x is reduced to nitrogen and water by injecting ammonia in the presence of a catalyst. The ammonia can be used in either the anhydrous or aqueous form. An ammonia injection grid is located upstream of the catalyst body and is designed to disperse ammonia uniformly throughout the exhaust flow before is enters the catalyst unit.

The SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation, if the catalyst is exposed to excessive temperatures over a prolonged period of time, or from chemical poisoning.

SCR has been used extensively on combustion turbines and to a somewhat lesser extent with boilers. The desired level of NO_x control is a function of the catalyst volume and ammonia-to-NO_x (NH_3/NO_x) ratio. For a given catalyst volume, higher NH_3/NO_x ratios can be used to achieve higher NO_x emission reductions, but can result in undesirable increased levels of unreacted ammonia, called ammonia slip.

- **Selective Non-catalytic Reduction**

SNCR is another post-combustion technology where NO_x is reduced by injecting ammonia or urea into a high-temperature region in the boiler exhaust gas path, without the influence of a catalyst. The SNCR technology requires gas temperatures in the range of 1600° to 2100°F. SNCR has been used extensively on boiler applications where consist fuel quality and firing rates can be maintained. For the proposed aux boiler, it is highly unlikely that consistent temperatures in the range of 1600° to 2100°F will be required. In addition, the ammonia or reagent injection grid would have to be positioned inside the package boiler unit to take advantage of the optimum injection temperature and still allow the required residence time to complete the reduction reaction, also highly unlikely in a small package boiler system. For these reasons, SNCR was not considered as a feasible BACT alternative for the auxiliary boiler.

Based on the information in this section, the following NO_x control technologies are considered technologically feasible for the proposed boiler:

- Low-NO_x burners (LNB)
- Flue gas recirculation (FGR)
- LNB with FGR
- Selective Catalytic Reduction (SCR).

Rank Technically Feasible Control Technologies by Control Effectiveness

The technically feasible control technologies listed above are ranked by NO_x control effectiveness in the traditional "top-down" format in the table below.

NO_x Control Technologies Ranked by Effectiveness

NO_x Control Alternative	**Available?**	**Technically Feasible?**	**NO_x Emission Reduction (%)**
SCR	Yes	Yes	90
SCONOx	Yes	No	90
LNB with FGR	Yes	Yes	70-90
LNB	Yes	Yes	40-85
FGR	Yes	Yes	40-70

Evaluate Most Effective Controls for BACT

For boilers such as the one proposed, low-NO_x burners have become standard. In addition, from Table 1 the highest level of emission control is provided by SCR. The proposed auxiliary boiler will only operate 2,500 hours/year. The applicant is proposing to use low-NO_x burners. The applicant has chosen a technology and an emissions limit which meets BACT for an auxiliary boiler anticipated to be fired less than or equal to 2,500 hours per year.

Select BACT

The applicant has chosen to apply low-NO_x burners and good combustion practices for the proposed auxiliary boiler. From the "top-down" analysis, this represents an equivalent level to the highest level of control for NO_x. This level of control is consistent with the control technologies listed in the RBLC, and in some cases exceeds the level of control for some recently permitted boilers. The proposed emission rate of 9 ppmvd @ 3% O_2 is also consistent with the lowest rates given in the RBLC.

Notwithstanding the above, the Applicant considered the application of SCR in addition to the BACT technologies proposed above. Data from the EPA RBLC as well as data from the South Coast AQMD BACT database were examined and noted the following:

- SCR applications on similar sized boilers resulted in NOx levels ranging from 3 to 7 ppmv at 3% O_2. With average NOx levels on the order of 3+ ppmv at 3% O_2.
- Several BACT cost analyses* were reviewed which showed that SCR capital costs ranged from as low as $3900/mmbtu-hr to as high as $10,000/mmbtu-hr (based on the heat rate of the unit in terms of mmbtu/hr).
- Data presented in the BACT analysis prepared for the Duke Energy Cliffside Unit 6/7 auxiliary boiler was used to represent the average capital cost for SCR on small auxiliary boilers. Using the data from this analysis and incorporating a slight cost increase to account for the period difference, i.e., 9/06 to 3/10, resulted in an approximate SCR capital cost for the BEPII aux boiler of $269,000.00.
- The anticipated reduction in NOx emissions was estimated to be from 9 to 3 ppmv.
- The annual incremental reduction in NOx emissions with the addition of SCR is approximately 0.46 tons per year.
- The annual average cost control effectiveness is ~$300,000 per ton reduced. This cost is extremely high and well above any of the know cost effectiveness values used by any regulatory air agency. (The cost analysis spreadsheet is attached - Attachment 1.)

Based on the above, SCR is not an incrementally cost effective add-on control for the proposed small aux boiler already proposed with LNBs.

**NCDAQ, Duke Cliffside Unit 6/7 Aux Boiler Top-Down BACT Analysis, ENSR, 9/06.*
**ETEC, Cutting SCR Cost for NOx Control, www.etecinc.net.*

Analysis of Control Requirements for Carbon Monoxide

Identify Potential Control Technologies

Carbon monoxide (CO) is a product of incomplete combustion. CO formation in a boiler is limited by ensuring complete and efficient combustion of the fuel. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions. Measures taken to minimize the formation of NO_X during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions. However, improved air/fuel mixing inherent in newer burner designs and control systems limits the impact of fuel staging on CO emissions.

The applicable NSPS does not contain requirements for CO, thus, there is no real baseline emission rate. Based on a review of the information provided in the RBLC database and knowledge related to the control of CO emissions from combustion sources, the following CO control approaches were identified:

- CO oxidation catalyst
- $SCONO_X$
- Good combustion control

Evaluate Control Technologies for Technical Feasibility

Oxidation catalysts have previously been applied to natural gas-fired boilers located in CO nonattainment areas, although not to the same extent as turbines. The catalyst lowers the activation energy for the oxidation of CO to CO_2 so that CO in the exhaust gas is converted to CO_2. There are numerous suppliers of oxidation catalyst systems, and as such this technology has been applied to natural gas-fired boilers of all sizes and is considered a demonstrated technology. CO oxidation catalysts, on average, cost approximately 50% of an SCR catalyst system for the unit under evaluation (*Ref: Industrial Boilers and Heat Recovery Steam Generators: Design, Applications.., Chapter 4-Emissions Controls, V. Ganapathy, 2003)*, which would result in a CO catalyst capital cost for the proposed aux boiler of approximately \$150,000. Annual operations costs for the CO catalyst on the aux boiler would be approximately \$45,000 based upon the assumption that the annual operations costs are 30% of the captial costs. The proposed package boiler would have to be cut in two in order to install a CO catalsyt, assuming of course that the package boiler design allowed for such a separation, and assuming the boiler design would allow the cut at the correct position in the boiler to achieve the correct exhaust gas temperature for the catalyst operation. For these reasons the use of a CO catalyst on a small package boiler is not considered feasible.

The $SCONO_X$ process for boilers was previously discussed as part of the NO_X BACT analysis; it is used to control both NO_x and CO. This control technology has not been achieved in practice and is not considered technically feasible for the proposed small aux boiler.

Good combustion control, as the name infers, is based upon maintaining good mixing, a proper fuel/air ratio, and adequate time at the required combustion temperature. This technology is technically feasible and is the most commonly used technology to control CO emissions. In fact, combustion control/design coupled with a CO catalyst, is the most stringent control technology listed in the RBLC for boilers.

Rank Technically Feasible Control Technologies by Control Effectiveness

The two technically feasible control technologies for CO are an oxidation catalyst and good combustion controls. Good combustion control is generally considered the baseline control technology for CO emissions. Thus, an oxidation catalyst, which is an add-on control technology, is considered the most stringent level of control for CO.

Evaluate Most Effective Controls for BACT

For boilers such as the one proposed, good combustion practices/design are considered standard. Thus, an oxidation catalyst provides the highest level of emission control. The proposed auxiliary boiler will operate less than or equal to 2,500 hours/year, and installation of a CO catalyst in the small package boiler is not considered feasible at this time. For these reasons the applicant is not proposing a CO catalyst. As a result, the applicant has chosen a control technology and emissions limit which meets BACT.

Select BACT

The applicant has chosen to apply good combustion practices for the proposed auxiliary boiler. From the "top-down" analysis, this represents a high level of control for CO for low use boilers. This level of control equals or exceeds the level of control technologies listed in the RBLC for boilers. The proposed emission rate of 50 ppmvd @ 3% O_2 is also consistent with the lowest rates given in the RBLC (considering the low use rate of the proposed boiler).

Analysis of Control Requirements for PM_{10}

PM_{10} is a Clean Air Act regulated pollutant defined as particulate matter equal to or less than a nominal aerodynamic particle diameter of 10 microns. Particulate matter is typically described as filterable and condensable PM. As presented in the turbine section, the amount of both filterable and condensable PM_{10} emissions from natural gas-fired combustion sources should be very small relative to the total exhaust flow. In addition, PM emissions from add-on control devices are typically higher than from uncontrolled natural gas-fired combustion units. Therefore, add-on PM_{10} controls such as fabric filters (baghouses), ESPs, wet scrubbers, venturi scrubbers, and coarse PM separation technologies such as cyclones and multi-clones, do not make practical sense and are not considered feasible or cost effective for utility natural gas-fired aux boilers.

Permit data from EPA's RBLC database beginning with January 1990 were searched for PM and PM_{10} BACT decisions and corresponding limit. In particular, data listed for similarly sized natural gas-fired boilers were reviewed in detail. Review of the RBLC database indicates PM/PM_{10} limits in the range of 0.001 – 5.0 lb/MMBtu. The PM_{10} emission rate for the proposed boiler is at the lower end of the range, at approximately 0.0045 lb/MMBtu. As noted before, it is difficult to make a direct comparison to the results in the RBLC because it is unclear as to whether the emission rate contained in the database includes both condensable and filterable PM.

In conclusion, because the proposed boiler will fire clean burning natural gas, and its combustion controls will be state-of-the-art, add-on controls are not considered feasible. Particulate emissions from the proposed unit will be controlled via proper design, operation, and maintenance. With respect to combustion controls, there are no significant toxic emissions, economic, energy, or environmental impacts.

Analysis of Control Requirements for VOC

This section presents the BACT analysis for VOC for the proposed natural gas-fired aux boiler. The VOC emissions from natural gas-fired combustion sources are the result of two possible formation pathways: incomplete combustion, and recombination of the products of incomplete combustion. The proposed boiler incorporates state-of-the-art combustion technology and is designed to achieve high combustion efficiencies. Additionally, the recombination of products of incomplete combustion is unlikely in well-controlled boilers because the conditions required for recombination are not present. As a result, the proposed boiler has a very low expected VOC emission rate.

Based on a review of the information provided in the RBLC database and knowledge related to the control of VOC emissions from combustion sources, and taking into account technology transfer from other combustion sources, the following VOC control approaches were identified:

- Thermal oxidation,
- Catalytic oxidation, and

- Good combustion practices (GCP), design, and operation.

Thermal oxidizers are used for combustion systems where VOC rates are high, such as waste incinerators. The thermal oxidizers for these types of sources are in the form of secondary combustion chambers and afterburners and are inherent to the combustion system's design. The VOC emissions from these types of sources are much higher because they combust fuels that are heterogeneous in nature and as a result it is difficult, if not impossible, to maintain the uniform time, temperature, and turbulence needed to ensure complete combustion. Thermal oxidation systems work by raising the VOC containing stream to the combustion temperature to allow the combustion process sufficient time to reach completion. The controlled VOC rates from these systems are still higher than those being proposed for this project without VOC control. Also, because thermal oxidizers combust fuel, a significant amount of NO_x emission can be generated. As such, thermal oxidizers are not considered further in this anlaysis.

Oxidation catalysts have traditionally been applied to the control of CO emissions from clean fuel fired combustion sources located in CO nonattainment areas. As discussed previously, this technology uses precious metal based catalysts to promote the oxidation of CO and unburned hydocarbon (of which a portion is VOC) to CO_2. The amount of VOC conversion is compound specific and a function of the available oxygen and operating temperature. See the CO catalyst discussion in the CO BACT section above for more data on the technical feasibility of this control option on small package boilers.

Good combustion design and operation is the primary approach used to control VOC emissions from combustion sources. The VOC controls, inherent in the design and operation of a unit, include the use of clean fuels such as natural gas, and advanced process controls to ensure complete combustion and the best fuel efficiency. The proposed boiler will be 100% natural gas-fired and is designed with state-of-the-art combustion controls to maximize conversion of the natural gas to CO_2, and minimize the production of VOC and CO.

Use of clean fuels (natural gas), and good combustion practices, are being proposed to control CO emissions, and such systems can also achieve VOC reductions. The proposed VOC emission rate is 5 ppmvd @ 3% O_2, which is consistent with low end values from the RBLC for similar-sized boilers and represents BACT for VOC.

Analysis of Control Requirements for SO_2

The new boiler will be designed and operated to minimize emissions and will be fired solely with natural gas, which is inherently low in sulfur. Sulfur dioxide is formed during combustion due to the oxidation of the sulfur in the fuel. Add-on control devices (e.g., wet or dry scrubbers, flue gas desulfurization) are typically used to control emissions from combustion sources firing higher sulfur fuels, such as coal. Flue gas desulfurization is not appropriate for use with low sulfur fuel, and is not considered for this project, because the achievable emission reduction is far too small for this option to be cost-effective. Also, the proposed emission rate of ~0.00233 lb/MMbtu is consistent with the lowest emission rates listed in the RBLC.

Cost Effectiveness and Other Impacts

Pursuant to the NSR/PSD Workshop Manual (10/99, Chapter B, page B.8) the applicant has chosen BACT limits which are equivalent to the top control alternatives for low use rate boilers, and as such it is not necessary to provide cost and other detailed information in regard to other control options. Based on the options chosen, the applicant is not aware of any additional toxics, energy, or other environmental media impacts that would result from the chosen BACT options.

Section 3 - BACT Analysis for the Combustion Turbines

Analysis of Control Requirements for Nitrogen Oxides

The proposed turbines/HRSGs at the BEPII station are rated as follows:

Turbine/HRSG Parameter	**Parameter Rating**
Fuel	Natural Gas
Heat Rating (GT w/DBs)	2241.2 mmbtu/hr (each)
K lbs steam/hr	643
Maximum daily hours of operation	24
Maximum annual hours of operation	8510
Proposed NOx Controls	DLN with SCR
Proposed CO Controls	CO Oxidation Catalsyt
Proposed VOC (POC) Controls	CO Oxidation Catalyst/Natural Gas
Proposed $PM_{10/2.5}$ and SOx Controls	Natural Gas/Clean Fuel

The proposed turbine/HRSG emissions as presently quantified are as follows (based on the above ratings and operations data): (per turbine/HRSG basis, steady state operation, with duct firing).

Pollutant	**Lbs/hr**	**Lbs/day**	**Tons/yr**
NOx	17.9	439.6	84.3
CO	10.9	261.6	54.2
VOC	6.3	158.4	25.9
SOx	3.6	84.6	5.8
$PM_{10/2.5}$	7.5	180.0	27.4

The table below presents the BACT proposal for the turbines/HRSGs based upon the data presented in this analysis.

BACT Pollutant	**BACT Limit**	**Proposed-Revised BACT**
NOx	2.0 ppmvd	Dry LNBs with SCR
CO	2.0 ppmvd	CO Catalyst
VOC	1-2 ppmvd*	CO Catalyst and Sole use of PUC Grade Natural Gas
SOx	0.2 gr S/100 scf	Sole use of PUC Grade Natural Gas (annual average S content)
$PM_{10/2.5}$	0.00661	Sole use of PUC Grade Natural Gas

*limit will vary depending upon the use or non-use of duct firing.

Identify Potential Control Technologies

The baseline NO_x emission rates for this analysis use the turbine supplier guarantee of 25 ppmvd @ 15 percent O_2 for the combustion turbines, i.e., turbines with DLN combustors. These emission rates provide a comparison for the evaluation of control effectiveness and feasibility. The maximum degree of control, which results in the lowest NO_x emission rate, is a combination of dry low-NO_x combustors (DLN) with either selective catalytic reduction (SCR) or SCONOx for the turbines.

The formation of NO_x from the combustion of fossil fuels can be attributed to two basic mechanisms – fuel NO_x and thermal NO_x. Fuel NO_x results from the oxidation of organically bound nitrogen in the fuel during the combustion process, and generally increases with increasing nitrogen content of the fuel. Because natural gas contains only small amounts of nitrogen, little fuel NO_x is formed during combustion.

The vast majority of the NO_x produced during the combustion of natural gas is from thermal NO_x, which results from a high-temperature reaction between nitrogen and oxygen in the combustion air. The generation of thermal NO_x is a function of combustion chamber design and the turbine operating parameters, including flame temperature, residence time (i.e., the amount of time the hot gas mixture is exposed to a given flame temperature), combustion pressure, and fuel/air ratios at the primary combustion zone. The rate of thermal NO_x formation is an exponential function of the flame temperature.

The reduction of NO_x emissions can be achieved by combustion controls and post-combustion flue gas treatment. Combustion modifications for turbines include both wet and dry combustion controls. Wet and dry combustion controls act to reduce the formation of NO_x during the combustion process, while post-combustion controls remove NO_x from the exhaust stream after it is generated. Thus, potential NO_x BACT for the combustion turbines and (with or without duct burners) include the following:

- Dry low-NO_x combustor design
- Catalytic combustors (e.g., XONON)
- Selective catalytic reduction (SCR)
- SCONOx

Evaluate Control Technologies for Technical Feasibility

The performance and technical feasibility of each “category” of NO_x controls listed above are discussed separately. A detailed discussion of post-combustion controls, which can control emissions from both the combustion turbines and duct burners, follows.

Dry Combustion Controls and Dry Low-NOx Combustors

Dry combustion controls reduce NO_x emissions without wet injection systems. Combustion modifications to reduce NO_x formation include lean combustion, reduced combustor residence time, lean premixed combustion, and two-stage rich/lean combustion. Lean combustion uses additional excess air (greater than stoichiometric air-to-fuel ratio) to cool the flame and thus reduce thermal NO_x formation. Reduced combustor residence times are achieved by introducing dilution air between the combustor and the turbine hot section. The rate of thermal NO_x formation is reduced because the combustion gases are at higher temperatures for a shorter time. The principle behind lean premixed combustion is to premix the fuel and air prior to combustion in order to provide a homogeneous air/fuel mixture, which acts to reduce the combustion temperatures, and thus thermal NO_x. Rich/lean combustion uses a fuel-rich primary stage, quenching, and then a fuel-lean secondary stage to reduce NO_x formation, however, this type of control is currently not very common.

Currently, the most widely used combustion controls are dry low-NO_x (DLN) combustors, which use lean premixed combustion to reduce the formation of thermal NO_x. Prior to the development of premix based dry-low NO_X combustors, fuel and air were injected separately into the turbine's combustor section where oxygen in the combustion air needed to support the combustion process diffused to the flame front located at the combustor's fuel burner. Simply put, the combustion occurred in a diffusion flame similar to that of a Bunsen burner. The result of this approach was a range of fuel-to-air ratios over which combustion occurred and a corresponding range of flame temperatures. The dry-low NO_X combustion process works to reduce the amount of thermal NO_X that is formed by lowering the overall flame temperature within the turbine combustor by premixing the fuel and air at controlled stoichiometric ratios prior to combustion. DLN combustion is effective in achieving NO_x emission levels comparable to the levels achieved using wet injection without the need for large volumes of purified water or steam. An increase in CO emissions can result from lower NO_x emission rates (in the range of 9 ppmv). However, negligible increases in CO are associated with controlled NO_x emission rates around 25 ppmv (the level for the proposed turbines before subsequent control). Thus, the increases in CO and VOC emissions that result from wet injection technology (not considered BACT) are not a factor with such DLN systems. Several turbine vendors have developed DLN systems for their turbines, therefore this technology is considered technically feasible.

Catalytic combustors use a catalytic reactor bed mounted within the combustor to burn a very lean fuel-air mixture. This technology has been commercially demonstrated under the trade name XONON in a 1.5 MW natural gas-fired turbine in Santa Clara, California. Commercial availability of the technology for a 200 MW GE Frame 7 natural gas-fired turbine was recently announced. The technology has also been announced as commercially available for some models of small turbines (around 10 MW or lower). The combustor used in the Santa Clara demonstration engine is generally comparable in size to that used in GE Frame 7F engines. The technology has not been announced commercially for the engines proposed for this project, thus a commercial quotation for the use of XONON is not available from the supplier, Catalytica Corporation. No turbine vendor, other than General Electric, has indicated the commercial availability of catalytic combustion systems at the present time. Furthermore, in 2001, GE indicated to the developers of the Pastoria Energy Project in California, that XONON technology for large combustion turbines such as the 7FA, would not be available for another 5 to 7 years. In the fourth quarter of 2002, Catalytica Corporation announced its first commercial operation of a catalytic combustion system on a 1.4 MW Kawasaki turbine. We conclude, that scale up of the system for turbines such as those proposed for BEPII, may still be several years into the future. Consequently, catalytic combustion controls are not considered commercially available for this project's turbines and are not discussed further.

Post-Combustion Controls

SCR—The SCR process is a post-combustion control technology in which injected ammonia reacts with NO_X in the presence of a catalyst to form water and nitrogen. The catalyst's active surface is usually a noble metal, base metal (titanium or vanadium) oxide, or a zeolite-based material. The geometric configuration of the catalyst body is designed for maximum surface area and minimum back-pressure on the turbine. An ammonia injection grid is located upstream of the catalyst body and is designed to disperse ammonia uniformly throughout the exhaust flow before it enters the catalyst unit. The desired level of NO_X emission reduction is a function of the catalyst volume, ammonia-to-NO_X (NH_3/NO_X) ratio, and temperature (450 F to 850 F typical range dependent upon type of catalyst). For a given catalyst volume, higher NH_3/NO_X ratios can be used to achieve higher NO_X emission reductions, but can result in undesired increased levels of unreacted NH_3 (called ammonia slip).

The SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include compounds of arsenic, sulfur, potassium, sodium, and calcium. In applications where natural gas is fired, a catalyst life of 5 to 7 years has been demonstrated.

SCR has been demonstrated effective at numerous installations throughout the United States. Typically, SCR is used in conjunction with other wet or dry NO_x combustion controls (e.g., DLN). Because SCR is a post-combustion control, emissions from both turbines and duct burners can be controlled (duct burners are proposed for BEPII). SCR requires the consumption of a reagent (ammonia or urea) and requires periodic catalyst replacement. Estimated levels of NO_x control in excess of 90 percent can be achieved.

SNCR—SNCR is another post-combustion technology where NO_x is reduced by injecting ammonia or urea into a high-temperature region, without the influence of a catalyst. The SNCR technology requires gas temperatures in the range of 1200° to 2000°F. The exhaust temperature for the proposed turbines ranges from 1030° to 1135°F, which is below the minimum SNCR operating temperature. Thus, some method of exhaust gas reheat, such as additional fuel combustion, would be required to achieve exhaust temperatures compatible with SNCR operations. SNCR is most commonly used with boilers, and there are no entries in the RBLC indicating the use of SNCR for turbines. SNCR is considered technologically infeasible for this project due to the temperature considerations. However, even if SNCR were technically feasible, it would not be able to achieve NO_x reductions comparable to SCR.

NSCR—NSCR uses a catalyst without injected reagents to reduce NO_x emissions in an exhaust gas stream. Typically, NSCR is used in automobile exhaust and rich-burn stationary IC engines, and employs a platinum/rhodium catalyst. NSCR is effective only in a stoichiometric or fuel-rich environment where the combustion gas is nearly depleted of oxygen, and this condition does not occur in turbine exhaust where the oxygen concentrations are typically between 14 and 16 percent. Consequently, NSCR is not technologically feasible for this project.

SCONOx—The SCONOx system uses a proprietary potassium carbonate coated oxidation catalyst to remove both NO_X and CO. SCONOx is a relatively new system originally produced and marketed by Goal Line Environmental Technologies that began commercial operation in California at the Federal Plant owned by the Sunlaw Cogeneration Partners in December 1996. According to an old press release dated December 1999, for gas turbine installations larger than 100 MW, ABB Alstom Power is Goal Line’s exclusive licensee for SCONOx. Other supplier/licensers, such as EmeraChem (EMx technology) are now offering the SCONOx technology.

The combustion turbine at the Federal facility was a GE LM-2500 that is approximately 23 MW in size, roughly one-eighth the size of each of the two combustion turbines proposed for this project (190 MW each). The application of the SCONOx system at the Federal Plant is the second-generation of the technology. The first generation was a pilot unit application that operated for ten months at another nearly identical GE LM-2500 based facility, the Growers facility, also owned by Sunlaw Cogeneration Partners. The SCONOx catalyst used at the pilot facility was transported to the Federal facility when the pilot unit was taken out of service.

Two power plant projects in California proposed by PG&E Generating Company have recently proposed the use of SCONOx for NO_x control, although both projects included switching to SCR as a contingency in their permit applications. The La Paloma Generating Project is a merchant plant that originally proposed using SCONOx on one out of its four turbines, although recently the decision was made to apply SCR to all four turbines.

The SCONOx system does not use a reagent such as ammonia but instead utilizes natural gas as the basis for a proprietary catalyst regeneration process. The NO present in the flue gas is reduced in a two-step process. First, NO is oxidized to NO_2 and adsorbed onto the catalyst. For the second step, a regenerative gas is passed across the catalyst periodically. This gas desorbs the NO_2 from the catalyst in a reducing atmosphere of hydrogen (H_2) which results in the formation of N_2 and water (H_2O) as the desorption products. For the regeneration/desorption step to occur there must be no oxygen (O_2) present during this step. The CO present in the flue gas is oxidized to CO_2 as part of the SCONOx process.

In order for the SCONOx technology to work properly, inlet/outlet dampers must continuously isolate one quarter of the catalyst blocks for regeneration. The SCONOx potassium carbonate layer has a limited adsorption capability and requires regeneration about once every 15 minutes in normal service. Each regeneration cycle requires approximately 3 to 5 minutes. The regenerative gas is passed through the isolated portion of the catalyst while the remaining catalyst is left open to the flue gas flow. After the isolated portion is regenerated, the next set of dampers must close and isolate the next section of catalyst for regeneration. This cycle is continuously repeated. Assuming a four section catalyst, and regeneration times of 15 minutes per section, results in approximately 35,000 regeneration cycles per year per power train.

At the Federal Plant the regenerative gas was produced from natural gas by processing it through a separate skid mounted processing unit. The resulting regenerative gas is approximately 3 percent nitrogen, 1.5 percent CO_2, and 4 percent H_2, with steam making up the balance. Steam is used to: (1) dilute the regenerative gas hydrogen concentration below the lower explosive level; (2) act as a carrier gas; (3) promote the purging of the catalyst bed of the oxygen containing flue gas; and (4) promote even distribution of the regeneration gas throughout the catalyst bed.

Goal Line tested several methods for producing regeneration gas, including a one step method where steam, natural gas, and air are reacted at 900°F using an auto thermal process. This process failed to produce consistent results and was abandoned. Goal Line stated that in future applications, the regeneration gas will be generated in the HRSG at a temperature of approximately 600 °F. This modified system to produce regeneration gas, and to our knowledge, has not been tested on any commercial applications and as such may not yet be demonstrated in practice.

Because the active regenerant gas is hydrogen, the regeneration process must be performed in an atmosphere of low oxygen to prevent dilution of the hydrogen. In practice, the oxygen present in the exhaust gas of combustion turbines is excluded from the catalyst bed by dividing the catalyst bed into a number of individual cells or compartments that are equipped with front and rear dampers that are closed at the beginning of each regeneration cycle. Obtaining a good seal with the dampers is key to: (1) preventing oxygen in the flue gas from disrupting the regeneration process, and (2) evenly distributing the regeneration gases across the catalyst.

Complete regeneration of the SCONOx catalyst system is dependent upon the proper functioning and sealing of these sets of dampers approximately four times each hour. Incomplete regeneration of the catalyst results in decreased system performance which in-turn results in increased NO_X emissions. Based on an article by Goal Line (Campbell et al, February 1997), probably the most important cause of reduced performance in the pilot unit was poor distribution of regeneration gas over the catalyst. As a result, several design changes were incorporated into the system located at the Federal Plant.

The SCONOx catalyst is very susceptible to fouling by very small amounts of sulfur in the flue gas. Sulfur causes the catalyst to lose activity. The impact of sulfur is minimized by a sulfur absorption catalyst, called SCOSOx, located upstream of the SCONOx catalyst. First, the SO_2 is oxidized and absorbed on to the catalyst. The SO_3 is then desorbed from the catalyst as part of the SCONOx regeneration process. The resulting byproduct of the regeneration is either H_2S (for systems located in the

HRSG where the flue gas temperature is below 450 °F at the catalyst) or SO_2 (for systems located in the HRSG where the flue gas temperature is above 450 °F).

In the case where H_2S is formed, it is converted back to SO_2 using an additional subsystem and directed into the exhaust downstream of the catalyst. In the case where SO_2 is the byproduct, it is directed into the turbine exhaust downstream of the catalyst. For a new construction project, the system would be placed in the HRSG at a point where SO_2 would be the primary product of the SCOSOx system.

According to present suppliers, the catalyst requires periodic washing at least annually. The "washing" consists of removing the catalyst modules from the unit and submerging each module in a vessel containing potassium carbonate. Thus, the adsorbent portion of the SCONOx process must be revitalized or replaced on a periodic basis (typically annually, but this period may be slightly longer for the newer generation design). For units the size of the proposed turbines, total required "wash" time could be on the order of seven days per turbine per wash cycle (including the time to allow safe entry to the HRSG). There are three options available for carrying out this washing:

1. To shut down the unit for approximately one week to clean the catalyst. Shut down includes a two-day cooling period prior to personnel entering the HRSG. Unbuttoning and entry into the HRSG. Dismantling of the catalyst support structure to allow the catalyst to be removed. Removal and dipping of the catalyst and then placement back into the HRSG. The actual logistics and design requirements of accomplishing this task on a unit the sizes of the proposed units are not yet known. In addition, this approach has the disadvantage of eliminating the ability to produce power during the outage.

2. Removal of the unit while on-line and replacement with clean catalyst while the other catalyst is washed. This approach is impractical in light of the need to assure that all damper seals maintain 100 percent integrity during the removal. The logistics associated with performing this operation on an application with units the size of the proposed units is also several fold more complicated because of the need to maintain tight damper seals where one side is at operating temperature and the other is at ambient in order to allow worker access. Several safety issues would also have to be overcome. This approach also requires that a spare catalyst set be purchased and stored. Thus, additional storage facilities would also be required.

3. Bring the catalyst off-line only long enough to permit removal of the used catalyst and replacement with a spare catalyst set. The removed catalyst is then washed and prepared for placement back in service at the next wash outage.

Any of the above operations will require several days to shutdown and cool the HRSG and SCOSOx/SCONOx sections to the point that the catalyst can be handled safely. Then each catalyst section will have to be removed, washed, dried, and put back in the HRSG before the units can startup again.

Past commercially quoted NO_x emission rates for the SCONOx system range from 2.0 ppm on a 3-hour average basis, representing a 90 percent reduction, to 1.0 ppm with no averaging period specified (96 percent reduction). System quotes from ABB Alstom Power for a GT26 turbine (rated at 274 MW) indicated a control efficiency of ~90 percent, i.e., NO_x ppm reductions from 20-25 ppm to 2.0-2.5 ppm. Because it has only been applied at relatively small combustion turbine facilities, there are several long-term operational concerns that exist with the SCONOx system. More recent data, for several facilities noted in the cost section which follows, indicates that SCONOx system quotes are on par with SCR systems quotes, i.e., NOx control rates of 90+%, with resulting NOx concentrations on the order of 2.0 to 2.5 ppmv.

Data obtained recently from the City of Redding (Electric Utility Dept.) for their Alstom GTX 100 unit (41-43 MW), indicates that the system was permitted at a NOx level of 2.0 ppmvd (Unit 5, Permit #03-TV-02, Condition C.7). Data obtained on this unit for a three (3) year demonstration program indicated the following:

- Numerous maintenance and repairs were required during the demonstration period including such items as damper seal gasket redesign and replacement, new steam reactor replacement, steam heater modifications, need to redesign and replace the regeneration distribution plate, install a larger sulfur filter on the steam reformer, implementation of a revised regeneration purge cycle, and addition of a 2nd layer of SOx catalyst.
- Upgrading of the SCONOx regeneration gas valves to Class 6 type.
- Washing of the SCONOx catalyst 11 times (in excess of the supplier stated wash cycle).
- Operations data on this unit shows that it rarely operated above the 60% load level, but yet had numerous periods when it exceeded NOx levels of both 2.0 and 2.5 ppmvd.
- According to Shasta County AQMD staff, the SCONOx system has to be pushed very hard to achieve NOx levels below 2.0 ppmvd.

Although technical concerns exist, the SCONOx system will be considered technologically feasible for the purposes of this analysis. Thus, based on the information in this section, the following NO_x control technologies are technologically feasible for the proposed project:

- Dry combustion controls/Dry low-NO_x combustors
- SCR (with a CO catalyst system)
- SCONOx

Rank Technically Feasible Control Technologies by Control Effectiveness

The technically feasible control technologies listed above are ranked by NO_x control effectiveness in the traditional "top-down" format in the table below.

NO_x Control Technologies Ranked by Effectiveness

NO_x Control Alternative	Available?	Technically Feasible?	NO_x Emissions (@ 15 percent O_2)	Environmental Impact	Energy Impacts
Selective Catalytic Reduction[a]	Yes	Yes	90 percent reduction 2.0 ppm	Ammonia slip	Decreased Efficiency
SCONOx	Yes[b]	Yes[c]	90 percent reduction 2.0 ppm	Reduced CO; potential reduction in VOC	Decreased Efficiency
Dry Low-NO_x Combustors	Yes	Yes	9-25 ppm	Reduced CO/VOC	Increased Efficiency

[a] Used in conjunction with wet or dry combustion controls and a CO Catalyst system.
[b] The availability of commercial guarantees for utility-scale projects is undetermined.
[c] This technology has been used on small (5 MW and 41 MW) gas turbines; it has not been, to our knowledge, demonstrated on large utility-scale gas turbines.

Evaluate Most Effective Controls for BACT

For large gas turbines such as those proposed, water and steam injection have been largely superseded by dry low-NO_x combustors, due to the superior emission control performance and increased efficiency. The proposed project plans to use dry low-NO_x combustors for the combustion turbines, thus no further discussion of water injection, steam injection, or dry low-NO_x combustors is necessary. The duct burners will be equipped with low-NO_x burners, which also represent a high level of emission control performance.

The level of NO_x control for SCR and SCONOx is essentially equivalent. However, the SCONOx process is much more complex both chemically as well as mechanically than the SCR technology. The principal differences between the two technologies are associated with whether the low emission levels proposed have been achieved in practice, the cost-effectiveness in achieving these levels, and secondary environmental impacts.

The following table compares the two processes. The SCR catalyst needs to be located in the appropriate section of the HRSG and maintained at the proper temperature. An SCR system also requires ammonia to be injected upstream of the catalyst with good mixing and even distribution. By comparison, the SCONOx process is much more complex in that the catalyst requires continuous regeneration, not just the presence of a reducing agent in the flue gas. Unlike SCR, the regeneration process for SCONOx requires a separate process to generate the regeneration gas and the catalyst must be separated from the flow of hot flue gas, during operation of the unit, for the regeneration process to occur. Thus, the need for the isolation louvers and the ability to frequently remove the SCONOx catalyst for washing.

Comparison of SCR and SCONOx Removal Technologies

	SCR	**SCONOx**	**SCONOx**
Process Parameters	NO_X Reduction	CO Reduction	NO_X Reduction
Catalyst	Yes	Yes	Yes
Reducing agent and equipment	Yes	No	Yes
Mechanical seals, positioners, and valves	No	Yes	Yes
Catalyst replacement	3-7 years	5 years	1st Row 7-10 years 2nd – 3rd Rows 30 years
Catalyst regeneration	NA	NA	At least annually
By products/ wastes	NH_3 slip	None	Potassium solution

Each SCONOx catalyst block also has inlet and outlet piping for the regeneration gas. In order to control flow of the regeneration gases, each inlet and outlet pipe has a set of electronically actuated valves. As such, each catalyst section has several actuators and valves that need to properly function and be maintained. In contrast, the SCR ammonia distribution system requires one automatic ammonia flow control valve and a set of manually adjusted valves used as part of the initial tuning of the ammonia injection grid. As a result, relative to the well-demonstrated application of SCR to natural gas-fired sources, the SCONOx processes may have a lower availability and higher operating and maintenance costs for the following reasons:

- The mechanically complex nature of the isolation louvers and positioners;
- The mechanically complex regeneration gas valving system; and,
- The added catalyst regeneration/replacement step (potassium carbonate solution washing).

Evaluation of Achieved in Practice

Commercial Availability: At least one vendor must offer this equipment for regular or full-scale operation in the United States. A performance warranty or guaranty must be available with the purchase of the control technology, as well as parts and service.

Reliability: All control technologies must have been installed and operated reliably for at least six months. If the operator did not require the basic equipment to operate daily, then the equipment must have at least 183 cumulative days of operation. During this period, the basic equipment must have operated (1) at a minimum of 50 percent design capacity; or (2) in a manner that is typical of the equipment in order to provide an expectation of continued reliability of the control technology.

Effectiveness: The control technology must be verified to perform effectively over the range of operation expected for that type of equipment. If the control technology will be allowed to operate at lesser effectiveness during certain modes of operation, then those modes of operation must be identified. The verification shall be based on a performance test or tests, when possible, or other performance data.

Technology Transfer: BACT is based on what is AIP for a category or class of source. However, EPA guidelines require that technology that is determined to be AIP for one category of source be considered for transfer to other source categories. There are two types of potentially transferable control technologies: (1) exhaust (backend) controls and (2) process controls and modifications. For the first type, technology transfer must be considered between source categories that produce similar exhaust streams. For the second type, technology transfer must be considered between source categories with similar processes.

Achieved in Practice Criteria Evaluation for SCR

SCR has been achieved in practice at a multitude of gas turbine installations throughout the world (including many sites in California and the US). This technology has also been demonstrated on large gas turbines through stack testing and continuous emissions monitoring systems (CEMS) at numerous facilities. SCR technology has been making continued advances over the past few years, although there are not that many facilities in operation designed to meet low NO_x permit limits of 2.0 ppm. There are numerous facilities operating at higher NO_x concentrations and experience from these facilities has allowed manufacturers to gain a better understanding of operations to optimize NO_x reduction, sizing of catalyst systems, reagent distribution, and process and control systems.

The following is an evaluation of the proposed AIP criteria as applied to the achievement of extremely low NO_x levels using SCR technology to control both turbine and duct burner emissions (although no duct burners are proposed for BEPII).

Commercial Availability: There are numerous manufacturers of SCR catalyst systems and standard commercial guarantees are available. Guaranteed NO_x levels of 2 ppm for turbines are commonly available.

Reliability: There are numerous similar installations operating with SCR control systems throughout the United States. This technology has been available for years and has demonstrated the ability to meet low NO_x emission rates. There has not been evidence of adverse effects on overall plant operations and reliability from SCR system operating at these levels.

Effectiveness: SCR technology has been demonstrated to achieve NO_x levels as low as 2 ppm. Due to system design (SCR inlet NO_x levels in excess of those for which the SCR system was designed that caused tripping from pre-mix to diffusion mode), short-term excursions have resulted in NO_x concentrations above 2 ppm. However, these excursions have not been associated with diminished effectiveness of the SCR system. Consequently, as with most control systems designed to reduce emissions to very low levels, the application of SCR should reflect the potential for infrequent NO_x excursions under specified conditions.

Technology Transfer: SCR has been demonstrated on numerous similar installations, and is therefore not a situation of technology transfer.

From the above discussion, SCR technology is considered to be achieved in practice. The technology is capable of achieving NO_x levels of 2 ppm and lower (in some specific instances). The current BACT guidelines used by EPA Region IX indicate that NO_x levels of 2.0 ppm on a 1 or 3-hour average basis are considered BACT for utility-scale gas turbines (with or without supplemental firing). The achievement of NO_x concentrations at these levels, on either a short term or long-term basis, have been demonstrated in practice at numerous sites. Thus, the proposed NO_x emission rate for the combustion turbines and duct burners of 2.0 ppm on a 1 or 3-hour average basis with the application of DLN combustors, DLN burners (HRSG duct burners) and SCR meets BACT.

Achieved in Practice Criteria Evaluation for SCONOx

The SCONOx system has only been applied at relatively small combustion turbine facilities (5 MW to 43 MW). As a result, there are several long-term operational concerns that exist with the SCONOx system. The SCONOx isolation louvers are moving parts in the flue gas stream that will require more frequent maintenance than any SCR components. In fact, no other combustion turbine systems or boilers have damper systems that require frequent operation from a fully open to a fully closed position.

Louver and damper systems are subject to mechanical and thermal stresses and strains that result from changes in temperatures associated with startup and shutdown as well as normal fluctuations in operating temperatures during load changes or changes in steam demand. These thermal/mechanical stresses result in operating and maintenance problems that are magnified with increases in scale. It should be noted that the change in placement/position of the SCONOx from the Federal facility location where the operating temperature is 320 °F to the supplier stated preferred, undemonstrated, location where the operating temperature will be 550 to 650 °F will increase the challenges associated with maintaining good seals during regeneration.

Another issue of concern is long-term catalyst availability and pricing. The SCONOx catalyst is a proprietary catalyst produced and available through only a very limited number of supplier/licensers, unlike SCR catalysts that are available through multiple suppliers that guarantee competitive pricing and availability. While supplier/licensers guarantee a catalyst life of three years, this catalyst life has not yet been commercially demonstrated over multiple applications, since only a few small units have been operated over that length of time. It is important to note that although SCR catalysts are now well demonstrated, during the first three years of operation on the initial five combustion turbine applications in the U.S. there were numerous catalyst change outs. Also, vendor guarantees are only good for replacement of the catalyst. The guarantee does not:

- Pay for lost revenues associated with downtime;
- Pay for the cost of any penalties resulting from any exceedence of a permit limit;
- Pay for the cost of removing SCOSOx/SCONOx and replacing it with an SCR system; and,
- Ensure that the catalyst will be replaced until the system works. Subsequent catalyst replacements are at the vendor’s discretion and it is left to the vendor discretion to abandon a particular application at any time.

All of these risks and their associated costs would be borne by the proposed project.

In a past application submitted for a Calpine facility, which is in EPA Region IX, an analysis of available CEMS data for the SCONOx system at the Federal facility was conducted. For the period covering July through December 1997, review of the available SCONOx data indicated that up to 12 exceedences per year could be expected for a 3.0 ppm, 3-hour average limit, even when exceedences related to startups and shutdowns were excluded. According to the analysis, for a combined cycle gas turbine with a limit of 2.0 ppm on a 3-hour average basis (the BACT/LAER levels recommended by several agencies), the 1997 SCONOx data from the Federal site indicate that this limit would be exceeded 44 times per year (excluding exceedences associated with startups and shutdowns).

Data was also obtained (for the analysis above) for the Federal facility from the period of April 1 through December 31, 1999. The more recent data are also consistent with the earlier data. According to the analysis, there were approximately 2,500 valid 1-hour average periods in the data set, excluding startups, shutdowns, and CEMS maintenance. For a 3.0 ppm limit based on a 3-hour averaging period, there were 20 exceedences (for the period April - December).

The analyses conducted show that the SCONOx system at the Federal facility is not capable of maintaining low NO_x levels of 3.0 ppm or less on a continuous basis. Moreover, the more recent data do not indicate improved performance over time.

In addition to performance-related concerns about the SCONOx system, there are several specific concerns regarding applying the SCONOx system to this project. Applying the system on a unit that is approximately 4-5 times larger than current known applications would require a major redesign of the dampers. The dampers at the Federal Plant were ~10 feet wide. The HRSG for this project would be approximately 40-45 feet wide.

A width that is 4+ times greater than that previously demonstrated results in concerns about designing dampers that provide an adequate seal when fully opened and closed during the numerous regeneration cycles required (i.e., as many as 35,000 times per year). This concern is heightened for an application at temperatures greater than those at the Federal Plant. In addition, potential interference between damper actuators and the regeneration gas injection system would need to be resolved, as well as issues on attaining and maintaining cross flow distribution of regeneration gas across a 40-45 foot catalyst section.

In an independent evaluation of SCONOx conducted by Stone & Webster, *Independent Technical Review – SCONOx Technology and Design Review*, from February 2000, it is reported that the initial operation of the SCONOx system at the second installation – the Genetics Institute turbine facility in Massachusetts – resulted in a rapid loss of performance due to poor operation of the regeneration system. The problem was traced to mechanical deficiencies, such as seal and gasket leakage, and numerous corrective actions were necessary. Further changes to the overall system included adding an external reformer and adding a sulfur filter to remove sulfur from the gas that feeds the external reformer. Moreover, Stone & Webster reports that a number of damper/seal design changes have been proposed by the suppliers/licensers based on results from testing of the system. This has been confirmed at the Redding Electric Utility Unit 5 facility (see comments above).

The following is an evaluation of the proposed AIP criteria as applied to the achievement of extremely low NO_x levels using SCONOx technology.

Commercial availability: SCONOx is available through only limited vendors and has been applied to a very limited number of small sized projects. In a press release, Goal Line/ABB indicated that commercial performance guarantees will be provided for SCONOx upon request. Due to the lack of information in the public domain, there are still questions regarding whether SCONOx technology is presently available with standard commercial guarantees for NO_x levels as low as 2.0 ppm. Another concern is whether the guarantee will be passed on by the HRSG vendors. Also, it is questionable that the system will be able to achieve 2.0 ppm controlling both the turbine and duct burner emissions, especially on a system with a large number of duct burners

Thus, numerous questions exist regarding the availability of a commercial guarantee for SCONOx. There are also numerous questions regarding scale-up of a SCONOx system to units of the size proposed for this project, consequently, problems associated with installation and operation have to be anticipated. As previously mentioned, even if a commercial guarantee is available, it does not cover the loss of revenue associated with downtime and the potential need to replace the SCONOx system with a SCR system if the required emission level cannot be achieved.

Reliability: Due to the fact that the SCONOx system has not been installed and operated for an extended period of time on a large utility-scale turbine, serious questions exist regarding the reliability of the system on such an installation. As the CEMS data from the Federal facility indicate, there has not been a demonstration of the SCONOx system's ability to meet NO_x levels lower than 3 ppm over an extended period of time without numerous exceedences. There have also been numerous design changes since the original SCONOx installation at the Federal plant. As witnessed in the Stone & Webster report, there have been problems at the Genetics Institute facility that have also required redesign. Consequently, the system that would be applied to a utility-scale application would also likely require design changes, thus, the reliability of the $SCONO_x$ system is substantially unknown.

Effectiveness: The analysis contained in Calpine's Metcalf Energy Center application demonstrates that the effectiveness of the SCONOx system to meet a 2.0 ppm limit on a consistent basis without exceedences is in question. Also, there have been numerous design changes associated with the SCONOx system and as such it is uncertain as to whether the actual system that would be installed on a larger, utility-scale turbine has been subjected to performance testing. From the available data, if SCONOx technology were to be used to achieve extremely low NO_x levels, it would be necessary to include permit conditions that would allow for the potentially frequent NO_x excursions under certain conditions. (See Redding Electric Utility comments above.)

Technology Transfer: SCONOx technology has been marketed as being capable of achieving low NO_x levels by SCAQMD and EPA (although the data from the Federal facility does not support this conclusion for an extended period of time, without numerous exceedences). The SCONOx system has not been installed on a large utility-scale turbine, and serious technical concerns have been enumerated in this application regarding such a scale-up of the technology. While it is not fair to regard this as technology transfer, it is fair to say that SCR has been installed on a large operating fleet of similar installations and is a more demonstrated technology.

In summary, the evaluation concludes that the SCONOx process is not commercially demonstrated on larger, utility-scale turbines and the economic risks to the project versus SCR are considerable. This is because the moderate temperature SCONOx process (post-HRSG location) has not been commercially demonstrated on units the size of the proposed project, and the high temperature SCONOx process (mid-HRSG location) proposed by the developers for large turbines has not been commercially demonstrated on any size unit. The significant technical/economic risks are a result of the following:

- No commercial demonstration of the SCONOx catalyst operation/regeneration at the mid-HRSG location proposed by the developers for large combustion turbine units like the proposed units;

- No commercial demonstration of the regeneration gas system proposed by the developers for large combustion turbine units like the proposed units;
- No commercial demonstration of a much larger more complex damper system needed to apply the SCONOx technology to very large CT/HRSG systems (concerns here are related to size, complexity, and placement of a damper system into a higher temperature position of the HRSG (i.e., 650 °F versus 350 °F)); and,
- The additional complexity of the SCONOx technology when compared to SCR. This additional complexity will result in lower project availability and could impact revenue generation.

The cost analysis presented herein was derived from the cost analysis data contained in the following BACT analyses:

- JEA-Greenland Energy Center, Black and Veatch, #149588, September 2008.
- FPL-West County Energy Center, August 2005.
- Satsop Combustion Turbine Project, Phase II, SCA Amendment #4, November 2001.

Each of the above noted BACT analyses were prepared for GE 7FA units, similar in size and rating to the proposed SGT6-5000F units for the BEPII project. In addition, the JEA and Satsop analyses compared the total costs of the proposed SCR/CO Catalyst systems to those of the SCONOx system. The table which follows presents a summary of the cost data from each of the above noted analyses on a per turbine basis.

Parameter	**JEA-Greenland**	**FPL-West County***	**Satsop CT**
SCR/CO Catalyst Capital Cost	$5,243,000	$2,737,771	$3,146,296
SCR/CO Catalyst Annual Ops Cost	$1,952,000	$1,221,691	$1,727,962
SCONOx Capital Cost	$27,912,000	$26,572,482	$14,297,500
SCONOx Annual Ops Cost	$6,693,000	$5,259,691	$4,757,834

*SCR costs only.

The table below presents a comparison of the average SCR/CO Catalyst versus average SCONOx estimated system capital and annual operating costs.

Summary of Combined NO_x/CO BACT Evaluation Results

Control System	**Capital Cost***	**Annualized Cost***
SCR/CO Catalyst	$4,200,000	$1,800,000
SCONOx	$22,900,000	$5,500,000

* All costs are presented on a per gas turbine/HRSG basis (rounded).

The Applicant believes the average costs above represent valid system costs applicable to the Siemens SGT6-5000F units proposed for the BEPII.

Select BACT

Based on the analysis presented, either SCR or SCONOx is generally considered capable of achieving NO_x levels of 2.0 ppm for combustion turbines. However, technical concerns are associated with the use of SCONOx. BACT for NO_x is considered to be the use of either SCR or SCONOx systems in conjunction with dry low-NO_x combustors to achieve NO_x levels for the combustion turbines of 2.0 ppm on a 1 or 3-hour average basis. The proposed project will have duct burners in the HRSG, and the proposed BACT rate needs to take this supplemental firing into account. Consequently, a NO_x level of 2.0 ppm on a 1 or 3-hour average basis is proposed, which is consistent with the lowest emission rates contained in the RBLCs, and found in other recent permitting approvals for similar sized power plants. Due to the technical concerns related to the use of SCONOx and the increased cost, the project proposes the use of SCR technology to meet this emission rate. Thus, the proposal is consistent with the BACT requirements for NO_x.

The applicant proposes to use SCR technology to meet a NO_x level of 2.0 ppm on a 1 or 3-hour average basis for the combustion turbines and duct burners with an ammonia slip level of 5 ppm. This proposal is consistent with BACT/LAER requirements and with emission rates found in numerous RBLC databases, as well recent permitting actions for similar sized power plants.

Analysis of Control Requirements for Carbon Monoxide

Identify Potential Control Technologies

CO is a product of incomplete combustion. CO formation is limited by ensuring complete and efficient combustion of the fuel in the combustion turbine. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO emissions. Measures taken to minimize the formation of NO_X during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions. However, improved air/fuel mixing inherent in newer combustor designs and control systems minimizes the impact of fuel staging on CO emissions.

The applicable NSPS does not contain requirements for CO, thus, there is no real baseline emission rate. For purposes of this analysis, an uncontrolled baseline value for CO was assumed to be 6 ppmv 15% O_2 per the turbine manufacturers data. Based on a review of the information provided in the RBLC database and knowledge related to the control of CO emissions from combustion sources, the following CO control approaches were identified:

- CO oxidation catalyst
- SCONOx
- Good combustion control

Evaluate Control Technologies for Technical Feasibility

Oxidation catalysts have previously been applied to natural gas-fired combustion turbines located in CO nonattainment areas, and there are numerous suppliers of oxidation catalyst systems. The catalyst lowers the activation energy for the oxidation of CO to CO_2 so that CO in the exhaust gas is converted to CO_2. For units that include duct firing, the placement of the catalyst is defined by the need to protect it from temperatures in excess of 1100 degrees F. Because the removal efficiency of CO is fairly constant above approximately 550 degrees F, there is only minimal impact to the catalyst's performance associated with placing it further back in the HRSG.

This technology has been applied to natural gas-fired combustion turbines of all sizes, and as such, is considered a demonstrated technology. CO removal efficiencies can vary, and can range from 60-90 percent. The oxidation catalyst is typically a precious metal catalyst, such as platinum. As the basis of control used to evaluate BACT for this application, a uncontrolled emissions rate of 6 ppmv at 15% O_2 was used, with a controlled rate of 2 ppm representing BACT levels (except for SCONOx as noted below).

The SCONOx process previously discussed as part of the NO_X BACT analysis is used to control both NO_x and CO. The SCONOx system provides for control of CO emissions to levels comparable to that of a conventional oxidizing catalyst. As part of the NO_x BACT discussion, it was noted that SCONOx is currently being applied to a limited number of small turbines (5-43 MW). Based on available literature describing the Federal Plant's operation, a 90 percent removal efficiency is evaluated. Technical concerns were identified in association with application of the technology on a larger combustion turbine, however, this technology will be considered technically feasible for this analysis.

Good combustion practices (GCP), as the name infers, is based upon maintaining good mixing, a proper fuel/air ratio, and adequate time at the required combustion temperature. This technology is technically feasible and is the most commonly used technology to control CO emissions. Good combustion control is considered the baseline control technology for CO emissions. Thus, an evaluation is provided for the two most stringent technically feasible control technologies, an oxidation catalyst and SCONOx.

<u>Rank Technically Feasible Control Technologies by Control Effectiveness</u>
Both an oxidation catalyst and SCONOx are considered in this analysis. Control efficiencies for both controls can vary widely. Consequently, the following analysis compares both control systems for potential CO control application.

<u>Evaluate Most Effective Controls for BACT</u>

The addition of a CO oxidation catalyst to reduce outlet emissions to 3 ppmv (excluding duct burner firing) was evaluated. This emissions level is achievable in practice and can be guaranteed. Note the following: <u>For SCONOx, a CO control level of 4 ppmvd was evaluated as potential BACT.</u> <u>The applicant could not find any data that would indicate that SCONOx could achieve-in-practice levels below 4.0 ppm and an accompanying VOC level of 1.0-2.0 ppmvd as proposed by the applicant.</u> If data cannot be acquired that indicates that SCONOx can achieve-in-practice a CO level of 3.0 ppmvd and a concurrent VOC level of 1.0-2.0 ppmvd, then SCONOx would have to be eliminated from the CO BACT analysis. The BACT evaluation that follows considered the energy, environmental, and economic impacts of the potential differing BACT levels noted above.

<u>Energy Impacts</u>: There is a pressure drop associated with each of the add-on controls that were evaluated. This pressure drop results in a backpressure on the combustion turbine, which in turn increases the heat rate (i.e., decreases the turbine's efficiency). The end result is an energy impact in the form of additional fuel to make the same amount of electricity as well as loss of generating capacity. Based on vendor information the increased backpressure on the turbine associated with oxidation catalyst systems is 1-1.5 inch w.c. The backpressure for a SCONOx system is typically greater. A backpressure of 5 inch w.c. is used for this analysis for SCONOx (vendor quotes range from 4" to 6.3" w.c.). Each inch w.c. of backpressure on the turbine results in a 0.15 percent increase in the heat rate (i.e., Btu/kwh). As a result, there is an increased fuel requirement to generate the same amount of power output. This penalty is included as an annual cost. It should also be noted that the additional fuel firing also results in additional emissions of some pollutants such as NO_x, PM_{10}, and SO_x.

<u>Environmental Impacts</u>: The spent oxidation catalyst is comprised of precious metals that are not considered toxic. This allows the catalyst to be handled and disposed of following normal waste procedures. Because of its precious metal content, the catalyst is often recycled by the manufacturer to recover the metals. The SCONOx system providers also take back the catalyst for reconditioning. The effective power reduction due to the pressure drop across the two add-on control technologies increases the emission rate of other criteria pollutants, such as NO_X, on a per unit of power output. The use of natural gas in the catalyst regeneration process for SCONOx will result in release of some natural gas

(methane) to the atmosphere due to leakage and venting. As noted above, the SCONOx catalyst also must be regenerated using a 4-step potassium carbonate bath and water rinses. Each module will generate approximately 1,500 gallons of wastewater per step. A SCONOx installation for the Project is expected to require the use of 40-60 modules. Even assuming the low end of only 40 modules, there would be approximately 500,000 gallons of wastewater produced each year for the two turbine/HRSGs. Production of the regeneration gas requires additional water to generate the steam needed for the process. Such an increase in water consumption and waste discharge associated with SCONOx is a considerable concern for the project (located in a desert environment with scarce water resources).

Another concern associated with SCONOx, as discussed in further detail in the NO_x BACT section, is that an installation of the system in the hot section of the HRSG has not been demonstrated to the satisfaction of the HRSG suppliers. HRSG suppliers are not yet willing to offer performance guarantees for their equipment if the $SCONO_x$ system is installed in the hot section of the HRSG.

Economic Impacts: A summary of the capital and annual costs associated with the installation of an SCR/CO oxidation catalyst and SCONOx are presented in the tables above (see NOx section). As shown, the per turbine/HRSG total installed capital cost for the SCR/CO oxidation catalyst system is $4.2 million. The total installed capital cost for the SCONOx system is $22.9 million.

The annual operating costs include catalyst replacement, energy impacts due to increased fuel usage, operating personnel, and maintenance. Throughout the life of the facility, the catalyst will require periodic replacement. Catalyst manufacturers are currently willing to guarantee a three-year catalyst life. Maintenance consists of the routine catalyst replacement costs. Labor for the operation and maintenance of the combustion control system is considered a part of the facilities normal operating expenses. The estimated annual operating cost associated with the SCR/ CO oxidation catalyst and SCONOx systems are $1.8 million and $5.5 million, respectively.

Select BACT

Based on the above discussion, both control technologies evaluated for CO control, an oxidation catalyst and SCONOx, are considered technically feasible and provide comparable reduction efficiencies. Even though the proposed project is located in a CO attainment area, and controls beyond combustion controls have not typically been required in attainment areas, the project is proposing the use of a CO oxidation catalyst to meet BACT requirements of 2 ppm (1 or 3 hour average). The use of an oxidation catalyst versus SCONOx is supported by the technical questions associated with SCONOx and the large difference in cost.

Analysis of Control Requirements for PM_{10}

PM_{10} is defined as particulate matter equal to or less than a nominal aerodynamic particle diameter of 10 microns. Particulate matter is typically described as filterable and condensable PM_{10}. The following discussion explains the formation of both for combustion sources.

For combustion sources, there are three potential sources of filterable PM_{10} emissions: mineral matter found in the fuel, solids or dust in the ambient air used for combustion, and unburned carbon or soot formed by incomplete combustion of the fuel. There is no source of mineral matter for natural gas-fired combustion sources, such as the proposed turbines and duct burners. In addition, as a precautionary measure to protect the high speed rotating equipment with a combustion turbine, the inlet combustion air is filtered prior to compression and use as combustion air. Also, the potential for soot formation in natural gas-fired turbines and duct burners is very low because of the excess air combustion conditions under which the fuel is burned. As a result, there is no real source of filterable PM_{10} originating from either the turbine or duct burners.

There are two sources of condensable PM_{10} for combustion sources: condensable organics that are the result of incomplete combustion and sulfuric acid mist that is found as sulfuric acid dihydrate ($H_2SO_4 \bullet 2H_2O$). For natural gas-fired sources, there should be no condensable organics originating from the source because the main components of natural gas (i.e., methane and ethane) are not condensable at the temperatures found in a Method 202 ice bath (the EPA reference method for measuring condensable PM). Thus, any condensed organics are from the ambient air. The most likely source of condensable PM_{10} from natural gas-fired combustion sources is sulfuric acid dihydrate, which results when sulfur in the fuel and in the ambient air is combusted and then cools.

Appendix M of 40 CFR Part 51 recommends that EPA Reference Methods 201or 201A be used to measure in-stack emissions of PM_{10}. As part of Appendix M, EPA also recognizes that condensible emissions not collected by an in-stack method are also PM_{10} and that these emissions contribute to ambient PM_{10} levels. As a result, to establish source specific contributions of PM_{10}, EPA suggests that PM_{10} measurements include both condensable particulate matter emissions and emissions measured by the in-stack methods. The use of EPA Reference Method 202 is recommended for determining the portion of condensable PM emissions that are PM_{10} from stationary sources.

The Method 201/201A and Method 202 portions of the sample are referred to as the filterable and condensable portions, because the PM_{10} emissions from a source represent the sum of these two measurements. Only the most recent NSR permits issued for turbines require the measurement of both the filterable and condensable portions. Most combustion turbine permits only require measurement of the filterable PM_{10}. Thus, comparison of the proposed PM_{10} emission rate to emission rates in the RBLC can be difficult, because the lower rates may represent only the filterable PM_{10} portion, and not be directly comparable.

Based upon the above discussion, the amount of both filterable and condensable PM_{10} emissions from the natural gas-fired combustion turbines and duct burners should be very small relative to the total exhaust flow. However, the vendor estimated base load PM_{10} emission rates are 7.5 lb/hr for each turbine and duct burner (HRSG). Vendor data on expected PM_{10} emission rates are designed to allow for the high level of test error inherent in sampling for an extremely small quantity of PM_{10} in a very large exhaust flow. In order to reduce the amount of variability/error, longer sampling times than are normally used by stack testers during compliance testing are required.

Permit data from various RBLC databases beginning with January 2000 were searched for PM and PM_{10} BACT decisions and corresponding limits. In particular, data listed for similarly sized natural gas-fired installations were reviewed in detail. Based on a review of the information provided in the RBLC databases, data gleaned from recent permitting decisions, and knowledge of combustion source PM and PM_{10} controls, and taking into account technology transfer from other combustion sources, the following PM_{10} control approaches were identified:

- Add-on control technologies including: electrostatic precipitators, baghouses or fabric collectors, and venturi or packed bed scrubbers;
- Combustion turbine lubrication oil exhaust vent mist eliminators;
- Combustion turbine inlet air filters and evaporative coolers;
- Use of clean (i.e., low ash) and low sulfur fuels such as distillate oil or natural gas; and
- Combustion controls and practices designed to minimize the production of soot.

Add-on controls are used to control particulate emissions from solid fuel (i.e., coal, coke, or waste) and residual oil-fired boilers because of the relatively high level of mineral matter (i.e., ash) in these fuels. There are no known applications of add-on controls for the purpose of controlling PM from distillate oil or natural gas-fired units, because these fuels have little to no ash that would contribute to the formation of PM or PM_{10}. Therefore, add-on PM_{10} controls do not make practical sense and are not considered feasible for natural gas-fired turbines and duct burners.

Review of the RBLC databases indicates PM/PM_{10} limits in the range of 0.0023 - 0.06 lb/MMBtu. The PM_{10} emission rate for the proposed combined cycle units is toward the lower end of the range, approximately 0.0033 lb/MMBtu. As noted before, it is difficult to make a direct comparison to the results in the RBLCs because it is unclear as to whether the emission rate contained in the database includes both condensable and filterable PM_{10}.

The proposed combustion turbines will include inlet air filters, which are required as part of the design to protect the rotating equipment. Inlet air coolers are included on units located in arid regions where high ambient temperatures combined with low relative humidity can sometimes preclude the ability to fire the turbine at full load. To overcome this, an inlet air cooler is placed downstream of the inlet air filters and upstream of the compressor air intake. Combustion air is drawn across a wetted surface (similar to a home humidifier screen) or fogging nozzles spray moisture directly into the inlet air. As a result of these processes, the inlet air is cooled and picks up moisture. These devices clean the ambient air upstream of the source, rather than controlling the emissions generated by the source. The combustion turbines will be equipped with lubrication oil exhaust vent mist eliminators. Therefore, these devices are not considered further in this analysis.

The proposed combustion turbines are natural gas fired. They are also equipped with state-of-the-art combustion controls to ensure maximum fuel efficiency. As a result, the conversion of fuel carbon to CO_2 will be maximized and the production of carbonaceous particulates minimized. With respect to combustion controls, there are no significant economic, energy, or environmental impacts.

In conclusion, because the combustion turbines will fire clean burning natural gas, and their combustion controls will be state-of-the-art, add-on PM controls are not considered feasible. Particulate emissions from the proposed combined cycle units will be controlled via proper combustor design, operation, and maintenance, coupled with sole use of natural gas fuel.

The proposed PM10/2.5 emission rate is 0.0033 lbs/mmbtu, which is consistent with values for natural gas fuel use, values from the RBLC and district databases, and represents BACT for PM10/2.5.

Analysis of Control Requirements for VOC

This section presents the BACT analysis for the proposed units having a potential to emit VOC (i.e., the combustion turbines and duct burners). The water circulated through the cooling tower will be noncontact cooling water and no water treatment chemicals containing VOC will be used. Consequently, the cooling tower does not have the potential to emit VOC and therefore has not been evaluated in this analysis.

The proposed combustion turbines are natural gas-fired combustion units. The VOC emissions from natural gas-fired combustion sources are the result of two possible formation pathways: incomplete combustion, and recombination of the products of incomplete combustion. Complete combustion is a function of three key variables: time, temperature, and turbulence. Once the combustion process begins, there must be enough time at the required combustion temperature to complete the process, and during combustion there must also be enough turbulence or mixing to ensure that the fuel gets enough oxygen from the combustion air.

Combustion systems with poor control of the fuel to air ratio, poor mixing, and/or insufficient time at combustion temperatures have higher VOC emissions than those with good controls. The proposed turbines incorporate state-of-the-art combustion technology, and are designed to achieve high combustion efficiencies. As a result, the proposed combustion equipment has very low expected VOC emission rates.

The two most prevalent components of natural gas, methane (~89.6 percent by vol.) and ethane (~5.8 percent by vol.), are not defined as VOCs. The remaining portions of natural gas are propane and trace quantities of higher molecular weight hydrocarbons, all of which are nearly 100 percent combusted. The high-energy efficiency of turbines and low fraction of VOCs in natural gas result in a very low VOC emissions rate for the proposed new units. Additionally, the recombination of products of incomplete combustion is unlikely in well controlled turbine systems because the conditions required for recombination are not present.

Based on a review of the information provided in the various RBLC databases, recent permitting decisions, and knowledge related to the control of VOC emissions from combustion sources, and taking into account technology transfer from other combustion sources, the following VOC control approaches were identified:

- Thermal oxidation,
- Catalytic oxidation, and
- Good combustion design and operation.

Thermal oxidizers are used for combustion systems where VOC rates are high, such as waste incinerators. The thermal oxidizers for these types of sources are in the form of secondary combustion chambers and afterburners and are inherent to the combustion system’s design. The VOC emissions from these types of sources are much higher because they combust fuels that are heterogeneous in nature and as a result it is difficult, if not impossible, to maintain the uniform time, temperature, and turbulence needed to ensure complete combustion. Thermal oxidation systems work by raising the VOC containing stream to the combustion temperature to allow the combustion process sufficient time to reach completion. The controlled VOC rates from these systems are still higher than those being proposed for this project without VOC control. Also, because thermal oxidizers combust fuel, a significant amount of NO_x emissions can be generated. As such, thermal oxidizers are not considered further in this analysis.

Oxidation catalysts have traditionally been applied to the control of CO emissions from clean fuel fired combustion sources located in CO nonattainment areas. As discussed previously, this technology uses precious metal based catalysts to promote the oxidation of CO and unburned hydrocarbon (of which a portion is VOC) to CO_2. The amount of VOC conversion is compound specific and a function of the available oxygen and operating temperature.

Good combustion design and operation is the primary approach used to control VOC emissions from combustion sources. The VOC controls, inherent in the design and operation of a unit, include the use of clean fuels such as natural gas, and advanced process controls to ensure complete combustion and the best fuel efficiency. The proposed turbines will be 100 percent natural gas-fired and each unit is designed with state-of-the-art combustion controls to maximize conversion of the natural gas to CO_2, and minimize the production of VOC and CO.

An oxidation catalyst is being proposed to control CO emissions, and such systems also achieve VOC reduction. Thus, the highest ranking, technically feasible control technology is being proposed for VOC control.

The proposed VOC emission rate is 1.0 ppmv without duct firing, and 2.0 ppmv with duct firing (1 or 3 hour average), which is consistent with natural gas fuel use, values from the RBLC and district databases, and represents BACT for VOC.

Analysis of Control Requirements for SO2

The new combustion turbines will be designed and operated to minimize emissions and will be fired solely with natural gas, which is inherently low in sulfur. Sulfur dioxide is formed during combustion due to the oxidation of the sulfur in the fuel. Add-on control devices (e.g., wet or dry scrubbers, flue gas desulfurization) are typically used to control emissions from combustion sources firing higher sulfur fuels, such as coal. Flue gas desulfurization is not appropriate for use with low sulfur fuel, and is not considered for this project, because the realizable emission reduction is far too small for this option to be cost-effective.

The use of natural gas is proposed as BACT for SO_2. Also, from the RBLC databases, and recent permitting decisions, there is no precedent for use of post-combustion control of SO_2 on combined cycle units firing natural gas.

The proposed annual average SOx emission rate is 1.52 lbs/hr (with duct firing, 0.2 gr S/100 scf), which is consistent with the use of natural gas fuel, values from the RBLC and district databases, and represents BACT for SOx.

Pursuant to the NSR/PSD Workshop Manual (10/99, Chapter B, page B.8) the applicant has chosen BACT limits which are equivalent to the top control alternatives, and as such is not required to provide cost and other detailed information in regard to other control options. Based on the options chosen, the applicant is not aware of any additional toxics, energy, or other environmental media impacts that would result from the chosen BACT options.

Section 4 – BACT Analysis for the Cooling Tower

Revised BACT and Economic Cost Analysis for Wet versus Dry Cooling

Background

Environmental Protection Agency staff at Region XI (EPA) have requested that a “top down” BACT analysis be prepared for the BEP II project with respect to the choice of cooling technologies for the proposed project. Caithness Blythe II (CBII) has proposed the use of wet cooling technology, while EPA staff believes that “dry cooling” technology may be a technological and economically feasible alternative. CBII believes that the incremental cost to implement a dry cooling system is significant and that the imposition of such a cooling alternative would jeopardize the project’s viability.

Technology

EPA staff believes that the use of dry cooling for BEP II as BACT for $PM_{10/2.5}$, is both technologically and economically feasible, and reasonable for the BEP II project. CBII staff disagree with this position, and our comments on the BACT and economic issues surrounding the imposition of “dry cooling” as BACT are presented herein.

Wet Cooling System

CBII proposed that BEP II be provided with a wet cooling system. The major cooling system components consist of a steam surface condenser, a cooling tower, and circulating water and condensate extraction pumps. CBII may be provided with an inlet chilling system that uses chilled water to cool the combustion turbine inlet air. The inlet chilling system will use an evaporative condenser or cooling tower, depending on refrigerant selected, to transfer heat removed from the inlet air stream to atmosphere. Either the evaporative condenser or cooling tower would be considered a form of wet cooling. CBII has estimated that 3300 acre feet of water would be used for plant cooling and other uses. The largest consumption of water would be evaporation from the main cooling tower. The source for makeup water would be on-site groundwater wells. The proposed wet cooling system is designed to meet the present BACT drift rate (see Table below) of 0.0005%, with total $PM_{10/2.5}$ emissions estimated as follows:

- 1.363 lbs/hr
- 32.71 lbs/day
- 5.97 tons/year

BACT for cooling towers is the installation and operation of high efficiency drift eliminators rated at 0.0005%. The following table presents a partial summary of facility BACT determinations used to establish the current BACT limit and technology.

BACT Summary for Cooling Towers

Project*	PM10/2.5 BACT Level	BACT Technology
PICO-Von Raesfeld Power Plant	0.0005% drift	HEDE
Inland Empire Energy Center	0.0005% drift	HEDE
Tesla Energy Center	0.0005% drift	HEDE
Vineyard Energy Center-Utah	0.0005% drift	HEDE
Blythe Energy Center	0.0005% drift	HEDE
Delta Energy Center	0.0005% drift	HEDE
Rio Linda Power Plant	0.0005% drift	HEDE
Las Vegas Cogen	0.0005% drift	HEDE
East Altamont Energy Center	0.0005% drift	HEDE
Mission-Sun Valley	0.0005% drift	HEDE
Mission-Walnut	0.0005% drift	HEDE
Pastoria Energy Center	0.0005% drift	HEDE
Liberty Energy V, XX, and XXIII	0.0005% drift	HEDE

*California projects unless specifically noted.
HEDE = high efficiency drift eliminators.

Dry Cooling System

EPA staff has proposed dry cooling as an alternate means of providing cooling for the plant. The major cooling system components would include an air cooled condenser (in place of the surface condenser and cooling tower), a large steam duct connecting the steam turbine and air cooled condenser, and condensate extraction pumps. The inlet chilling system would use an independent air cooled condenser to transfer heat removed from the inlet air stream to atmosphere. A dry cooling system essentially has no $PM_{10/2.5}$

emissions. It is important to note that with a dry cooling system, the parasitic power costs and lost revenue due to decreased plant output must be accounted for in the cost analysis.

Dry cooling negatively impacts plant efficiency in two main areas; (1) decreased steam turbine output, and (2) increased parasitic losses (or auxiliary loads. With a dry cooling system, a reasonable design criterion for an air cooled condenser is to size the condenser for an initial dry bulb temperature difference (ITD) of about 45 ^{o}F. The ITD is the difference between the steam temperature and the ambient dry bulb temperature. Typical dry system designs result in an increase in the steam turbine exhaust pressure on the order of 2.5 times the pressure experienced with a wet cooling system. The potential loss of steam turbine output due to an increase in exhaust pressure will represent a significant operational impact. In addition, because dry cooling systems reject 100% of the heat by means of sensible heat transfer, the dry cooling alternative needs to move far more air than the proposed wet system. An example of this is the dry cooling alternative proposed for the Inland Empire Energy Center (IEEC, 2002), which proposed a wet cooling system of 14 cells, with each cell requiring a 250 hp fan motor, for a total load draw of approximately 4,750 bhp. An alternative dry system as designed for IEEC consisted of an 80 cell unit, with each cell utilizing a 150 hp motor, for a total load draw of 11,040 bhp. The difference in the two systems, on an hourly horsepower basis, amounts to 6290 hp, or 55.1 million hp-hrs/year (based on 8760 hours of operation).

The table which follows presents a summary comparison of the estimated BEP II plant losses for the wet versus dry cooling systems.

Decrease in Plant Output Due to Dry Cooling Plant Losses	
Operating Condition	**Net Loss in Power Generation Due to Dry Cooling**
Hot Day, base load, with duct firing	46 MW per hour
Hot day, base load, without duct firing	31 MW per hour
Average day, base load, with duct firing	10 MW per hour
Average day, base load, without duct firing	8 MW per hour

The $PM_{10/2.5}$ emissions from the wet cooling system, as proposed, would be eliminated if dry cooling is used, but under the MDAQMD NSR regulations, the $PM_{10/2.5}$ from the wet cooling system (along with other applicable $PM_{10/2.5}$ from the proposed facility) will be required to be offset to show a net air quality benefit. Therefore, regardless of whether the cooling system $PM_{10/2.5}$ is eliminated, or offset under the air agency NSR rules, the emissions will be mitigated to below a level of significance. Additionally, the project site, which lies well within the jurisdictional boundaries of the Mohave Desert AQMD, is currently classified as “unclassified” for both PM10 and PM2.5. As such, the Prevention of Significant Deterioration permitting program requirements apply to the site for both $PM_{10/2.5}$, which confirms that BACT is required. CBII staff believes that dry cooling technology, which results in virtually no emissions of $PM_{10/2.5}$, is essentially a LAER technology.

Economic Analyses

Attachment 1 presents the estimated costs for the proposed wet cooling system, while Attachment 2 presents the estimated costs for a proposed dry cooling system in the size range required for the BEP II project. The following table presents a summary of the data in Attachments 1 and 2.

Cost Summary for Cooling Options		
Cost Category	**Wet Cooling**	**Dry Cooling**
Total Direct Capital Costs	$22,203,450	$42,000,000
Total Indirect Capital Costs	$880,000	Included above
Total Capital Costs	$25,391,800	$46,200,000
Annual Direct Operating Costs	$1,370,000	$1,771,700
Annual Indirect Operating Costs	$2,400	$2,400
Total Annualized Costs	$4,434,600	$7,345,800

Per the table above, the difference in capital cost for a dry system versus a wet system is approximately $20 million. The difference in annual operating costs for a dry system versus a wet system is approximately $2.9 million.

Assuming a typical operations year which anticipates 5820 hours/year of turbine operation without duct firing (average day, base load,), and 2200 hours/year of turbine operation with duct firing (hot day, base load), results in an average power loss of 147,760 MW-hrs per year, or 4,432,800 MW-hrs over the 30 year lifetime of the facility. Data compiled by the California Energy Commission and the California PUC (May 2008) indicates that the average busbar cost of electricity generation for a combined cycle plant was $0.0938 per kwh, or $93.82 per MW-hr. "Busbar" cost is defined as the price of the electric power leaving the plant, and it includes all capital, fuel, and operating costs. Since the power purchase agreement for BEP II has not yet been finalized, we have based the monetary plant losses due to dry cooling on the $93.82 MW-hr value, as this value would represent the minimum average loss to the plant for producing a MW-hr that could not be sold due to dry cooling parasitic load. The annual average monetary loss would be approximately $13,862,843. This loss divided by the 5.97 tpy of $PM_{10/2.5}$ reduced results in a monetary loss cost of $2,322,084 per ton per year.

Adding these annual monetary loss costs to the annual operating costs as computed in Attachments 2 and 3 for the wet and dry cooling options, results in an average annual cost of $2,809,722 to reduce one (1) ton of $PM_{10/2.5}$ from the proposed wet cooling system (see last page of dry cooling cost analysis). CBII staff believes that these costs are excessively high in terms of $/ton for reducing $PM_{10/2.5}$ emissions.

Revised Blythe II Emissions Using CO at 2.0 PPM

Table 5.2-4
Combustion Turbine/HRSG Emissions for the Project
(Steady State Operation-Per Turbine/HRSG)

Pollutant	Emission Factor and Units	Max Hour Emissions without Duct Firing (lbs)	Max Hour Emissions with Duct Firing (lbs)	Max Daily Emissions (lbs)*
NO_x	2.0 ppmvd	16.2	17.9	439.6
CO	2.0 ppmvd	9.9	10.9	261.6
VOC	1 ppmvd (unfired) 2 ppmvd (w/duct firing)	2.9	6.3	158.4
SOx[1]	0.75 gr S/100scf	3.2	3.6	86.4
SOx[2]	0.2 gr S/100scf	1.52	1.52	-
PM10/2.5	<=0.00661 lbs/MMBtu	6.0	7.5	180.0
NH_3	10.0 ppmvd[3]	32.07	32.07	769.68

* Assumes 24-hours of full load with duct firing (no startup/shutdown)

[1] short term fuel sulfur limit

[2] long term fuel sulfur limit

[3] Once the slip exceeds 5 ppm, the catalyst will be scheduled for replacement

Table 5.2-5
Combustion Turbine Startup and Shutdown Emissions

Parameter/Mode	Cold Startup	Warm/Hot Startup	Shutdown
NO_x, lbs/event	120.9	81.9	29.7
CO, lbs/event	140.4	58.5	25.3
VOC, lbs/event	50.7	46.8	20.9
PM10/2.5, lbs/event	22.5	7.5	7.5
SO_x, lbs/event	10.8	1.8	1.8
Event Time, minutes (hours)	180 minutes (3 hours)	30 minutes (0.5 hour)	30 minutes (0.5 hours)
Number of Events/Year	10	300	310

Table 5.2-6
Combustion Turbine/HRSG Emissions for the Project (Including Base Load, Cold and Warm/Hot Startup and Shutdown, Whichever is Greater)

Pollutant	Emission Factor	Max Hour Emissions (pounds)	Max Daily Emissions (pounds)	Max Annual Emissions (tons)
NO_x	N/A	83.2	591.7	84.3

Table 5.2-6
Combustion Turbine/HRSG Emissions for the Project (Including Base Load, Cold and Warm/Hot Startup and Shutdown, Whichever is Greater)

Pollutant	Emission Factor	Max Hour Emissions (pounds)	Max Daily Emissions (pounds)	Max Annual Emissions (tons)
CO	N/A	137.8	450.02	54.2
VOCs	N/A	46.8	252.5	25.9
SOx	N/A	3.6	84.6	5.8
PM10/2.5	N/A	7.5	180.0	27.4

See Appendix 5.2A, for detailed emissions and operational data.

Table 5.2-7
Cooling Tower, Fire Pump Engine, and Aux Boiler Emissions for the Project

Cooling Tower				
Pollutant	**TDS, mg/L***	**Max Hour Emissions (pounds)**	**Max Daily Emissions (pounds)**	**Max Annual Emissions (tons)**
PM10/2.5	5050	1.37	32.8	5.98
Fire Pump Engine				
Pollutant	**g/hp-hr**	**Max Hour Emissions (pounds)**	**Max Daily Emissions (pounds)**	**Max Annual Emissions (tons)**
PM10/2.5	0.103	0.07	0.07	0.0018
NOx	2.61	1.74	1.74	0.045
SOx	15 ppmw	0.004	0.004	0.0001
CO	0.84	0.556	0.556	0.015
VOC	0.104	0.212	0.212	0.006
Auxiliary Boiler				
Pollutant	**Emissions Factor**	**Max Hour Emissions (pounds)**	**Max Daily Emissions (pounds)**	**Max Annual Emissions (tons)**
PM10/2.5	0.0045 lbs/MMBtu	0.27	6.5	0.338
NOx	9.0 ppmvd	0.55	13.2	0.688
SOx	0.00233 lbs/MMBtu	0.14	3.36	0.175
CO	50.0 ppmvd	1.85	44.4	2.31
VOC	5.0 ppmvd	0.11	2.6	0.138

Notes:
*The TDS presented in the Air Section is the maximum expected in the cooling tower circulating water.
Drift fraction = 0.0005 percent
Aux boiler emissions based on 24-hours per day during turbine off days

Table 5.2-8 presents a summary of the total proposed facility operational emissions.

Table 5.2-8
Summary of Facility Emissions for the Project

Pollutant	pounds/hour	pounds/day	tons/year
NO_x	103.39	1,183.30	168.44
CO	150.77	900.52	110.72
VOCs	57.32	505.11	51.90
SO_x	7.34	169.2	11.84
TSP/PM10/2.5	15.26	346.62	61.0
NH_3	64.4	1,545.60	272.91

Including startup and shutdown emissions, fire pump engine, aux boiler, and cooling tower PM10.

Table 5.2-9 compares the proposed potential to emit for the new Project to the inventoried actual emissions for the current site activities.

Table 5.2-9
Proposed Project Potential to Emit (Tons/Year)

Pollutant	Current Permitted Site Emissions	Project Increase, PTE*	Total PTE
NO_x	202.0	(-33.56)	168.44
CO	685.0	(-574.28)	110.72
VOCs	25.0	26.90	51.90
SO_x	23.0	(-11.16)	11.84
TSP/PM10	61.0	0	61.0
PM2.5	61.0	0	61.0

Notes:
*Calculated emissions based on increases and decreases.

Modeling Analysis for PM2.5 and 1-hour NO_2

The Blythe Energy Project, Phase II (BEP II) impact analyses were reviewed to determine compliance with recent USEPA guidance for 24-hour PM-2.5 modeling and the new 1-hour NO_2 National Ambient Air Quality Standard (NAAQS) of 100 ppb (about 188 ug/m3), based on the 3-year average of the 98th percentile annual daily 1-hour maxima.

24-Hour PM-2.5 Impact Analyses

The USEPA Model Clearinghouse recently issued a Feb 26, 2010 guidance document for PM-2.5 (*"Model Clearinghouse Review of Modeling Procedures for Demonstrating Compliance with PM2.5 NAAQS"* Memorandum from Tyler Fox to USEPA Region 6). In that memo, the USEPA recommends the use of the average of the 1st highest modeled 24-hour impacts over 5 years to be added to the 98th percentile monitored background concentration to be protective of the NAAQS. In other words, adding the 98th percentile modeled impact to the 98th percentile background concentration may not be conservative with respect to demonstrating compliance with the 24-hour PM-2.5 NAAQS.

In the BEP II impact analyses, the 24-hour PM-2.5 background concentration presented in Table 5.2-16 of 28 $\mu g/m^3$ is actually the maximum 24-hour value measured over any of the past three years of data available at the time the application was prepared (i.e., Victorville for 2006-2008). The appropriate 98th percentile 3-year average based on USEPA guidance would be 19.0 $\mu g/m^3$ (i.e., for 2005-2007 as the last three years of data meeting data sufficiency requirements based on the California Air Resource Board iADAM website). Thus, the representative 24-hour PM-2.5 background concentration selected for the modeling analyses was very conservative when compared to the USEPA recommended background value (i.e., 28 vs. 19.0 $\mu g/m^3$).

The modeled 24-hour PM-2.5 concentrations in the BEP II impact analyses were 2.85 and 1.65 $\mu g/m^3$ for the maximum and 5-year average 98th percentile concentrations, respectively, for the facility only impact analyses. The combined (modeled plus background) concentration based on USEPA guidance (conservatively using the maximum 24-hour impact rather than the 5-year average of the 1st highest concentrations) would be 21.85 $\mu g/m^3$ (2.85 plus 19.0 $\mu g/m^3$), far less than the combined impact of 30.9 $\mu g/m^3$ presented in Table 5.2-18. For the cumulative PM-2.5 impact analyses, the modeled impact presented in Table 5.2-26 was the 5-year average of the 98th percentile concentration. Remodeling this impact to find the maximum 24-hour impact (for all five years of meteorological data) gives 6.3 $\mu g/m^3$. Adding this to the USEPA-recommended background value gives 25.3 $\mu g/m^3$ (6.3 plus 19.0 $\mu g/m^3$), far less than the combined impact of 31.8 $\mu g/m^3$ presented in Table 5.2-26 in the PSD Permit Application.

Therefore, as shown above, the 24-hour PM-2.5 analyses presented in the permit application are very conservative when compared to recent USEPA modeling guidance.

1-Hour NO_2 NAAQS

In the February 9, 2010 Federal Register (75 FR 6474), USEPA promulgated a new primary NO_2 NAAQS of 100 ppb (about 188 $\mu g/m^3$), based on the 3-year average of the annual 98th percentile daily 1-hour maximum NO_2 concentrations. For modeling purposes, the 98th percentile daily maximum is the 8th highest daily maximum and, according the above PM-2.5 guidance memo, a 5-year average is used (rather than 3-years) when five years of meteorological data are modeled. Since AERMOD is NOT currently configured to calculate/present the average of the eighth highest daily 1-hour maximum concentrations (just the average of the annual eighth highest 24-hour impacts for PM-2.5), a post-processor was developed as suggested in the USEPA document *"Notice Regarding Modeling for New Hourly NO2 NAAQS"* updated 02/25/2010. For the modeling analysis, the Ozone Limiting Method (OLM) included within the AERMOD code was used to convert modeled NO_X concentrations to NO_2. Hourly ozone data from the nearby Blythe monitoring station was used by AERMOD in the OLM analysis, which was concurrent with the meteorological data modeled. As part of the OLM analysis, concurrent hourly background NO_2 concentrations were added to modeled NO_2-OLM impacts before determining the maximum 5-year average of the 8th highest (98th percentile) daily 1-hour maximum concentrations. This use of concurrent ozone and background NO2 concentrations in the OLM analysis is consistent with past guidance contained in the *"Guideline on Air Quality Models"* when OLM was discussed in any detail (i.e., 3rd Level Screening in Draft GAQM Revisions proposed November 1984 through GAQM Supplement B issued February 1995). Since NO_2 data are not measured at the Blythe monitoring station, the nearest representative NO_2 station used in the background monitoring determination in the application was used (i.e., Victorville). Results of the AERMOD OLM analysis with the post-processor to determine the maximum 5-year average of the 98th percentile (8th highest) daily maximum 1-hour NO_2 combined (modeled plus background) concentrations are shown below:

Facility Normal Operations	179 µg/m^3
Facility Startup/Shutdown Periods	138 µg/m^3
Facility Commissioning Activities	143 µg/m^3

All of these impacts are less than the new 1-hour NO_2 NAAQS.

Attachments

Table A – Aux Boiler SCR Cost Analysis

Table B – Wet Cooling Option Costs

Table C – Dry Cooling Option Costs

TABLE A

Blythe Energy Project-Phase II
Blythe, CA.
NOx SCR Control Costs/Aux Boiler
CAPITAL COST SUMMARY

DIRECT CAPITAL COSTS (2003 $)		Explanation of Cost Estimates
		per Unit basis
1. Purchased Equipment:		Base Cost
A) Equipment Cost, EC	$269,000	
B) Auxiliary Equipment, AE	$0	default (included in EC)
B) Instrumentation & Controls	$26,900	10% of EC+AE
C) Freight	$13,450	5% of EC+AE
D) Taxes	$19,503	7.25% of EC+AE (California avg sales tax value)
Total Purchased Equip. Costs (TEC):	$328,853	Sum 1A thru 1E
2. Installation Costs:		
A) Foundation & Supports	$39,462	12% of TEC
B) Erection and Handling	$49,328	15% of TEC
C) Electrical	$3,289	1% of TEC
D) Piping	$6,577	2% of TEC
E) Insulation	$3,289	1% of TEC
F) Painting	$3,289	1% of TEC
G) Site Preparation	$16,443	5% of TEC
Total Installation Costs (TIC):	$121,675	Sum 2A thru 2G
Total Direct Capital Costs (TDCC):	$450,528	TEC + TIC
INDIRECT CAPITAL COSTS		
1. Engineering & Supervision	$32,885	10% of TEC
2. Construction and Field Exp.	$32,885	10% of TEC
3. Contractor Fees	$0	0% of TEC
4. Start-up	$3,289	1 % of TEC
5. Performance Testing	$3,289	1% of TEC
Total Indirect Capital Costs (TICC):	$72,348	Sum 1 thru 5
Total Direct & Indirect Capital Costs (TDICC):	$522,875	TDCC + TICC
Contingency Costs = 5%	$26,144	5% TDICC
TOTAL CAPITAL COSTS (TCC):	$549,019	TDICC + Contingency

TABLE A
Blythe Energy Project-Phase II
Blythe, CA.
NOx SCR Control Costs/Aux Boiler
ANNUAL OPERATING COST SUMMARY

DIRECT OPERATING COSTS (2003 $)		Explanation of Cost Estimates
		per Unit basis
1. Operating Labor	$9,450	0.5hr/shift, $35 hr, 3 shifts/day, 180 days
2. Supervisory Labor	$1,418	15% of Operating Labor
3. Maintenance Labor	$9,450	.5 hr/shift, 3 shifts/day, $35/hr, 180 days
4. Maintenance Materials	$9,450	100% of Maintenance Labor
5. Electricity Expense	$2,595	10 Kw/hr, $0.06 kw/hr, 4324 hrs/yr
6. Catalyst Cost (replace/disposal)	$50,000	7 year lifespan and replacement
7. Ammonia Costs	$3,240	~5 lb/hr NH3, $300/ton NH3
8. Fuel Penalty	$0	unknown for small boilers
9. Annualized Catalyst Cost	$9,300	CRF, 7%, 7 yrs
Total Direct Operating Costs (TDOC):	$44,903	Sum 1 through 8
INDIRECT OPERATING COSTS		
1. Overhead	$26,942	60% of Ops and Maintenance
2. Property Tax	$5,490	1% of TCC (avg national value)
3. Insurance	$5,490	1% of TCC (avg national value)
4. General Administrative	$10,980	2% of TCC (avg national value)
5. Capital Recovery Cost (7%, 30 years)	$44,300	CRF x TCC (OMB interest rate, estimated equipment life)
Total Capital Charges Costs (TCCC):	$93,202	Sum 1 thru 5
TOTAL ANNUALIZED OPERATING COSTS:	$138,105	TDOC + TCCC

TABLE A
Blythe Energy Project-Phase II
Blythe, CA.
NOx SCR Control Costs/Aux Boiler
NOx Emission Summary

Base Concentration-Controlled	9.0	ppm (proposed BACT w/LNB)
Annual Emission Rate	0.69	tpy
SCR Incremental Controlled Emissions Case		
NOx Concentration	3.0	ppm (add SCR to LNB)
Annual Emission Rate:	0.23	tpy
NOx Reduction from Uncontrolled Case:	0.46	tpy
Control Cost Effectiveness:	**$301,539**	per ton NOx (incremental cost over base case)

References:

OAQPS - OAQPS Cost Control Manual, 6th ED., November 2001, EPA 452/B-02-001.

Air Compliance Advisor, Version 7.5, 8-15-2003, EPA-OAQPS.

Default escalation values derived from:

1. Wyoming DEQ/DAQ, BACT Cost Analysis Report, PR-Chapter 6, Section 2, O&G Production Facilities, 3/2010, per data supplied by J. W. Williams, Inc.
2. North Carolina DAQ, Duke Energy, Cliffside Aux Boiler BACT Analysis, 9-14-2006.

Table B

BEP II

Blythe, Ca.

Wet Cooling Tower Costs

CAPITAL COST SUMMARY

DIRECT CAPITAL COSTS (2003 $)		Explanation of Cost Estimates **per BEP II facility design**
1. Purchased Equipment:		Base Cost
A) Process/Control System	$18,900,000	Wet tower (with 11 cells), etc. (3)
B) Instrumentation & Controls(No CEMS)	$165,000	(2)
C) Freight & Taxes	$2,478,450	OAQPS 8% Taxes; 5% Freight; on 1A & 1B
Total Purchased Equip. Costs (TEC):	$21,543,450	Sum 1A,1B,1C
2. Installation Costs:		
A) Foundation & Supports	$0	Included in 1A above
B) Erection and Handling	$0	Included in 1A above
C) Electrical	$660,000	(2)
D) Piping	$0	Included in 1A above
E) Insulation	$0	Included in 1A above
F) Painting	$0	Included in 1A above
G) Site Preparation	$0	Included in 1A above
Total Installation Costs (TINC):	$660,000	Sum 2A,2B,2C,2D,2E,2F,2G
Total Direct Capital Costs (TDCC):	$22,203,450	Sum TEC,TINC
INDIRECT CAPITAL COSTS		
1. Engineering & Supervision	$440,000	(2)
2. Construction and Field Exp.	$440,000	(2)
3. Contractor Fees	$0	
4. Start-up	$0	
5. Performance Testing	$0	
Total Indirect Capital Costs (TICC):	$880,000	Sum 1,2,3,4,5,6
Total Direct & Indirect Capital Costs (TDICC):	$23,083,450	Sum TDCC,TICC
Contingency (@10%):	$2,308,300	10% TDICC (std engineering accuracy) (2)
TOTAL CAPITAL COSTS (TCC):	$25,391,800	Sum TDICC,Contingency

Table B
BEP II
Blythe, Ca.
Wet Cooling Tower Costs
ANNUAL OPERATING COST SUMMARY

DIRECT OPERATING COSTS (2003 $)		Explanation of Cost Estimates **per note 2**
1. Operating/Supervisory Labor	$4,000	0.1 man-years @ $40K/man-year
2. Maintenance Labor	$8,000	0.2 man-years @ $40K/man-year
3. Parts and Maintenance	$100,000	(3)
4. Chemical Costs	$350,000	(3)
5. Electricity Costs	$485,000	(3)
6. Water Costs	$154,000	(2)
7. Water Pumping Costs	$71,000	(3)
8. Other Misc Costs	$198,000	sludge disposal costs
Total Direct Operating Costs (TDOC):	$1,370,000	Sum 1 through 8
INDIRECT OPERATING COSTS		
1. Overhead	$2,400	OAQPS 60% Total Labor
Total Indirect Operating Costs (TIOC):	$2,400	Sum 1
CAPITAL CHARGES COSTS		
1. Property Tax	$253,900	OAQPS 1% TCC
2. Insurance	$253,900	OAQPS 1% TCC
3. General Administrative	$507,800	OAQPS 2% TCC
4. Capital Recovery Cost (8.06%, 30 years)	$2,046,600	8.06%, TCC
Total Capital Charges Costs (TCCC):	$3,062,200	Sum 1,2,3,4
TOTAL ANNUALIZED OPERATING COSTS:	$4,434,600	Sum TDOC,TIOC,TCCC

References:
(1) OAQPS - OAQPS Cost Control Manual, 5th ED., February 1996.
(2) Costs based on EAEC-AFC 19 cell tower costs scaled down to BEP II 11 cell tower.
(3) BEP II 2005 analysis report, Tables 2 and 3.

Table C
BEP II
Blythe, Ca.
Dry Cooling Tower Costs
CAPITAL COST SUMMARY

DIRECT CAPITAL COSTS (2003 $)		Explanation of Cost Estimates **per sources (2) and (3)**
1. Purchased Equipment:		Base Cost
A) Process/Control System	$42,000,000	Dry tower with support systems
B) Instrumentation & Controls(No CEMS)	$0	Included in 1A above
C) Freight & Taxes	$0	Included in 1A above
Total Purchased Equip. Costs (TEC):	$42,000,000	Sum 1A,1B,1C
2. Installation Costs:		
A) Foundation & Supports	$0	Included in 1A above
B) Erection and Handling	$0	Included in 1A above
C) Electrical	$0	Included in 1A above
D) Piping	$0	Included in 1A above
E) Insulation	$0	Included in 1A above
F) Painting	$0	Included in 1A above
G) Site Preparation	$0	Included in 1A above
Total Installation Costs (TINC):	$0	Sum 2A,2B,2C,2D,2E,2F,2G
Total Direct Capital Costs (TDCC):	$42,000,000	Sum TEC,TINC
INDIRECT CAPITAL COSTS		
1. Engineering & Supervision	$0	Included in 1A above
2. Construction and Field Exp.	$0	Included in 1A above
3. Contractor Fees	$0	Included in 1A above
4. Start-up	$0	Included in 1A above
5. Performance Testing	$0	Included in 1A above
Total Indirect Capital Costs (TICC):	$0	Sum 1,2,3,4,5,6
Total Direct & Indirect Capital Costs (TDICC):	$42,000,000	Sum TDCC,TICC
Contingency (@10%):	$4,200,000	10% TDICC (std engineering accuracy) (2)
TOTAL CAPITAL COSTS (TCC):	$46,200,000	Sum TDICC,Contingency

Table C
BEP II
Blythe, Ca.
Dry Cooling Tower Costs
ANNUAL OPERATING COST SUMMARY

DIRECT OPERATING COSTS (2003 $)		Explanation of Cost Estimates **per sources (2) and (3)**
1. Operating/Supervisory Labor	$4,000	0.1 man-years @ $40K/man-year
2. Maintenance Labor	$8,000	0.2 man-years @ $40K/man-year
3. Parts and Maintenance	$20,000	(3)
4. Chemical Costs	$20,000	(3)
5. Electricity Costs	$1,600,000	(3)
6. Water Costs	$1,700	(2)
7. Water Pumping Costs	$40,000	(3)
8. Other Misc Costs	$78,000	sludge disposal costs
9. Power sales penalty	$13,862,843	147,760 Mw-hrs @ $93.82 Mw-hr
Total Direct Operating Costs (TDOC):	$15,634,543	Sum 1 through 8
INDIRECT OPERATING COSTS		
1. Overhead	$2,400	OAQPS 60% Total Labor
Total Indirect Operating Costs (TIOC):	$2,400	Sum 1
CAPITAL CHARGES COSTS		
1. Property Tax	$462,000	OAQPS 1% TCC
2. Insurance	$462,000	OAQPS 1% TCC
3. General Administrative	$924,000	OAQPS 2% TCC
4. Capital Recovery Cost (8.06%, 30 years)	$3,723,700	8.06%, TCC
Total Capital Charges Costs (TCCC):	$5,571,700	Sum 1,2,3,4
TOTAL ANNUALIZED OPERATING COSTS:	$21,208,643	Sum TDOC,TIOC,TCCC
Wet Cooling Annual Costs	$4,434,600	from wet cooling calculations and assumptions
Difference	$16,774,043	cost difference for technologies
Cost per ton reduced	$2,809,722	PM10/2.5 cost per ton reduced

References:
(1) OAQPS - OAQPS Cost Control Manual, 5th ED., February 1996.
(2) Costs based on EAEC-AFC 19 cell tower costs scaled down to BEP II 11 cell tower.
(3) BEP II 2005 analysis report, Tables 2 and 3.