San Joaquin Valley
Unified Air Pollution Control District

Best Performance Standard (BPS) x.x.xx

Class	Gaseous Fuel-Fired Boilers
Category	**Gaseous Fuel-Fired Boilers with Rated Steam Pressure 75 psig and Greater**
Best Performance Standard	1. The boiler shall have a minimum thermal efficiency of 95% at the maximum firing rate or, alternatively, shall be 1) equipped with an economizer designed at maximum firing rate which will either reduce the temperature of the economizer flue gas outlet to a value no greater than 20 ^{o}F above the temperature of the inlet water to the economizer or will heat the water to a temperature which is 30 ^{o}F less than the steam temperature at the steam drum , or 2) shall be equipped with other economizer and/or heat recovery options which will collectively provide an equivalent energy recovery from the boiler, and
	2. For boilers with a rated firing duty of 20 MMBtu/hr or greater, when the boiler feedwater is to be deaerated or otherwise preheated with steam and the temperature of the water supply to the deaerator or steam heater is equal to or less than 160 ^{o}F (combined makeup and recovered condensate), the boiler shall include a 2nd stage economizer to heat the feedwater flowing to the deaerator/heater or shall incorporate other economizer/heat recovery options which will collectively provide an equivalent energy recovery from the boiler. The second stage economizer design shall be based on reducing the temperature of the 2nd stage economizer flue gas outlet to a value no greater than 20 ^{o}F above the temperature of the inlet water to the 2nd stage economizer when the boiler is operating at the maximum firing rate, and
	3. Electric motors driving combustion air fans, induced draft fans and boiler feedwater pumps shall have an efficiency meeting the standards of the National Electrical Manufacturer's Association (NEMA) for "premium efficiency" motors and shall each be operated with a variable frequency speed control or equivalent for control of flow through the fan or pump, and
	4. For boilers with rated fired duty in excess of 20 MMBtu/hr and a rated steam pressure of 125 psig or greater, the boiler shall be 1) equipped with an O_2 trim system which will control oxygen content of the stack gases to a maximum of 2 volume % dry basis at maximum firing and 2) shall limit the recirculation of flue gas to a value not exceeding 10 percent of total flue gas volume.
Percentage Achieved GHG Emission Reduction Relative to Baseline Emissions	7.0%

District Project Number	C-1100388
Evaluating Engineer	Dennis Roberts, P.E.
Lead Engineer	Martin Keast
Initial Public Notice Date	April 8, 2010
Final Public Notice Date	April 30, 2010
Determination Effective Date	TBD

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I. Best Performance Standard (BPS) Determination Introduction

A. Purpose

To assist permit applicants, project proponents, and interested parties in assessing and reducing the impacts of project specific greenhouse gas emissions (GHG) on global climate change from stationary source projects, the San Joaquin Valley Air Pollution Control District (District) has adopted the policy*: District Policy – Addressing GHG Emission Impacts for Stationary Source Projects Under CEQA When Serving as the Lead Agency.* This policy applies to projects for which the District has discretionary approval authority over the project and the District serves as the lead agency for CEQA purposes. Nonetheless, land use agencies can refer to it as guidance for projects that include stationary sources of emissions. The policy relies on the use of performance based standards, otherwise known as Best Performance Standards (BPS) to assess significance of project specific greenhouse gas emissions on global climate change during the environmental review process, as required by CEQA. Use of BPS is a method of streamlining the CEQA process of determining significance and is not a required emission reduction measure. Projects implementing BPS would be determined to have a less than cumulatively significant impact. Otherwise, demonstration of a 29 percent reduction in GHG emissions, from business-as-usual, is required to determine that a project would have a less than cumulatively significant impact.

B. Definitions

Best Performance Standard for Stationary Source Projects is – a specific Class and Category, the most effective, District approved, Achieved-In-Practice means of reducing or limiting GHG emissions from a GHG emissions source, that is also economically feasible per the definition of achieved-in-practice. BPS includes equipment type, equipment design, and operational and maintenance practices for the identified service, operation, or emissions unit class and category.

Business-as-Usual is - the emissions for a type of equipment or operation within an identified class and category projected for the year 2020, assuming no change in GHG emissions per unit of activity as established for the baseline period, 2002-2004. To relate BAU to an emissions generating activity, the District proposes to establish emission factors per unit of activity, for each class and category, using the 2002-2004 baseline period as the reference.

Category is - a District approved subdivision within a “class” as identified by unique operational or technical aspects.

Class is - the broadest District approved division of stationary GHG sources based on fundamental type of equipment or industrial classification of the source operation.

C. Determining Project Significance Using BPS

Use of BPS is a method of determining significance of project specific GHG emission impacts using established specifications. BPS is not a required mitigation of project related impacts. Use of BPS would streamline the significance determination process by pre-quantifying the emission reductions that would be achieved by a specific GHG emission reduction measure and pre-approving the use of such a measure to reduce project-related GHG emissions.

GHG emissions can be directly emitted from stationary sources of air pollution requiring operating permits from the District, or they may be emitted indirectly, as a result of increased electrical power usage, for instance. For traditional stationary source projects, BPS includes equipment type, equipment design, and operational and maintenance practices for the identified service, operation, or emissions unit class and category.

II. Summary of BPS Determination Phases

The District has established *Gaseous Fuel-Fired Boilers with Rated Steam Pressure 75 psig and Greater* as a separate class and category which requires implementation of a Best Performance Standard (BPS) pursuant to the District's Climate Change Action Plan (CCAP). The District's determination of the BPS for this class and category has been made using the phased BPS development process established in the District's Final Staff Report, Addressing Greenhouse Gas Emissions under the California Environmental Quality Act. A summary of the specific implementation of the phased BPS development process for this specific determination is as follows:

BPS Development Process Phases for *Gaseous Fuel-Fired Boilers with Rated Steam Pressure 75 psig and Greater*			
Phase	**Description**	**Date**	**Comments**
1	Initial Public Process	02/10/10	The District's intent notice sent by email to interested parties registered on the District's GHG web site for this class and category is attached as Appendix 1.
2	BPS Development	N/A	See Section III of this evaluation document.
3	Public Review	04/08/10	The District's BPS determination notice sent by email to interested parties registered on the District's GHG web site for this class and category and a list of individuals receiving notification are attached as Appendix 2.
4	Public Comments	05/06/10	Public Comments received during the Public Review will be addresses before finalizing the BPS determination.

III. Class and Category

Gaseous Fuel-Fired Boilers is recognized as a distinct class based on the following:

- Boilers represent a distinct operation (indirect heat transfer from combustion to heat or boil water) when compared to all other permit units currently regulated by the District.

- The District already considers this a distinct class with respect to Best Available Control Technology (BACT) for criteria pollutant emissions.

- This is a distinct class with respect to the District's prohibitory rules for criteria pollutant emissions (Rules 4306 - 4308 and 4320).

- The District's current prohibitory rules currently only allow gaseous fuel firing (with liquid fuel allowed as a backup only for PUC natural gas during curtailment periods) or solid fuel-fired boilers (Rule 4352). Gaseous fuel fired units differ substantially from solid fuel units with respect to design requirements and thus are considered to be a separate class.

Gaseous Fuel-Fired Boilers with Rated Steam Pressure 75 psig and Greater is recognized as a distinct category of boilers based on the following:

- Boilers which produce steam at 75 psig and greater must theoretically have a stack temperature exceeding 320 ^{o}F due to the saturation temperature of the steam. To control corrosion in the boiler, feedwater to a boiler is typically deaerated which necessitate that it be heated to 225+ ^{o}F prior to delivery to the boiler. Given a stack temperature exceeding 320 ^{o}F and a feedwater temperature of 225 ^{o}F, the District's analysis indicates that a boiler operating with these parameters can accommodate installation of an economizer designed for a 20 ^{o}F approach without resulting in steaming operation at the economizer whereas boilers with lower steam pressures as well as hot water boilers may not be able to accommodate such a design without encountering steaming problems due to their lower stack temperature(see discussion under Step 2.A of this evaluation).

IV. BPS Development

STEP 1. Establish Baseline Emissions Factor for Class and Category

The Baseline Emission Factor (BEF) is defined as the three-year average (2002-2004) of GHG emissions for a particular class and category of equipment in the San Joaquin Valley (SJV), expressed as annual GHG emissions per unit of activity. The Baseline Emission Factor is calculated by first defining an operation which is representative of the average population of units of this type in the SJV during the Baseline Period and then determining the specific emissions per unit throughput for the representative unit.

A. Representative Baseline Operation

For *Gaseous Fuel-Fired Boilers with Rated Steam Pressure 75 psig and Greater*, the representative baseline operation has been determined to be a steam boiler with the following attributes:

Natural gas-fired forced draft steam boiler with a rated operating pressure of 125 psig and a thermal efficiency of 82% and with the following features:

- *Ultra Low NOx burner operating with 30% flue gas recirculation (FGR)*
- *Oxygen content of 4.5 volume % dry basis in the stack gas*
- *Conventional efficiency (87%) electric motor drivers, not equipped with speed control, for the combustion air fan and the boiler feed water pump*

This determination was based on:

Discussions with boiler manufacturer representatives indicate that historical demand for boilers in the range of 50 to 100 psig operating pressure has been very small. For boilers rated 125 psig and above, the most typical unit supplied has been in the range of 125 to 150 psig with an average closer to 125 psig. Therefore, a 125 psig boiler was selected to represent the average operating unit during the Baseline Period for this class and category.

To establish the thermal efficiency of the representative boiler the following considerations were made:

o Boiler manufacturer's representatives, familiar with the fleet of operating boilers in the San Joaquin Valley, have estimated that the fleet average during the Baseline Period for boilers in this class and category was approximately 82%.

- A study[1] of boiler efficiency projects prepared for the California Climate Action Registry indicates an average boiler efficiency of 83% for all types of boilers in the western United States for the years 1990 to 2003.

Based on the above, an efficiency of 82% was selected since this value was estimated specifically for the San Joaquin Valley plus the consideration that the study value of 83% would be less applicable to this class and category since it included lower pressure boilers with inherently lower stack temperatures which would be expected to have somewhat higher efficiency than the average for this class and category.

An operating stack oxygen content of 4.5% and an FGR rate of 30% were selected for the baseline period based on estimates by boiler manufacturer representatives which were in turn based on typical excess air and FGR requirements for operation of with an ultra low NOx burner at a 9 ppmv NOx emission level (consistent with the District's prohibitory rule for boilers during the Baseline Period).

Conventional, single speed electric motors were assumed for all mechanical equipment drivers based on the observation that, although premium efficiency motors with variable speed drives have been a relatively common specification for new facilities and retrofits in the last decade, commercial and industrial boilers have a useful life span of 20 to 30 years and therefore it is expected that the boiler fleet in place during the Baseline Period would not have included a significant population of boilers equipped with high efficiency mechanical drives.

B. Basis and Assumptions

- All direct GHG emissions are produced due to combustion of natural gas in this unit.
- Thermal efficiency of the unit is 82%. The stack temperature has been estimated at approximately 460 ^{o}F based on 4.5 % O2 in the stack gas and an assumed convection/radiation loss from the boiler amounting to 0.5% of firing.
- At the stated conditions, combustion of 1 MMBtu of natural gas produces 12,590 scf of flue gas including moisture and sufficient excess air to result in an oxygen concentration of 4.5% based on District's thermal/combustion analysis.
- The enthalpy of 125 psig steam is 1193.8 Btu/lb (per steam tables).
- The temperature of the combined feed water to the boiler plant (combined flow of returned condensate and makeup water to the boiler upstream of any steam pre-heaters) is assumed to be 140 ^{o}F.

[1] Development of Issues Papers for GHG Reduction Project Types: Boiler Efficiency Projects, Science Applications International Corporation, page 32, January 7, 2009.

- The enthalpy of 140 ^{o}F water is 107.0 Btu/lb (per steam tables).
- GHG emissions are stated as "CO_2 equivalents" ($CO_{2(e)}$) which includes the global warming potential of methane and nitrous oxide emissions associated with gaseous fuel combustion.
- The GHG emission factor for natural gas combustion is 117 lb-$CO_{2(e)}$/MMBtu per CCAR document[2].
- Indirect emissions are produced due to operation of the combustion air fan and the boiler feed water pump.
- Static efficiency of the combustion air fan is assumed to be 60%.
- Flue gas side pressure drop for the boiler is assumed to be 20 inches water column when operating without FGR plus an allowance for additional dynamic loss due to FGR which is assumed to be proportional to the square of the mass flow. For an FGR rate of 30 %, pressure drop is Base Pressure Drop x $(1 + \%_{FGR})^2 = 20 \times 1.3^2 = 33.8$ inches W.C..
- Differential operating pressure for the boiler feed water pump (constant speed) is assumed as follows:

	psi
Steam Drum Pressure	125
Allowance for Relief Valve	50
Control Valve	25
Dynamic Losses (economizer & other)	10
Less Deaerator Pressure	-5
Total	200

- The boiler feedwater pump has a capacity requirement of 5% over the net steam rate to allow for blowdown and deaerator steam. The pump therefore delivers 1050 lb water at a density of 8 lb/gallon (131 gallons) per 1000 gallons of steam produced.
- Hydraulic efficiency of the feed water pump is assumed to be 60%.
- Electric motor efficiency is estimated at 87% for a conventional electric motor.
- Indirect emissions from electric power consumption are calculated based on the current PG&E electric power generation factor of 0.524 lb-CO2(e) per kWh

C. Unit of Activity

To relate Business-as-Usual to an emissions generating activity, it is necessary to establish an emission factor per unit of activity, for the established class and category, using the 2002-2004 baseline period as the reference.

[2] California Climate Change Action Registry (CCAR), Version 3.1, January, 2009 (Appendix C, Tables C.7 and C.8)

The resulting emissions factor is the combination of:

GHG emission reductions achieved through technology, and

GHG emission reductions achieved through changes in activity efficiencies

A unit of activity for this class and category will be taken as 1000 lbs of steam production.

For purposes of this BPS determination, it will be assumed that GHG emissions reductions achieved through changes in activity efficiencies are not significant. This assumption has been made based on:

- This class and category of equipment is used at a wide range of facilities, diverse in operation and size, making it difficult to characterize specific efficiency improvements.

- A search of available literature did not yield any data which would support an estimate of GHG emission from boilers in this class and category since the baseline period based on changes in activity efficiencies.

D. Calculations

The Baseline Emission Factor (BEF) is the sum of the direct (GHG_D) and indirect (GHG_I) emissions (on a per unit of activity basis), stated as lb-CO2 equivalent:

$BEF = GHG_D + GHG_I$

<u>Direct Emissions:</u>

$GHG_D = E_f \times SFC$

E_f = 117 lb- $CO_{2(e)}$/MMBtu of natural gas

$$SFC = \text{Specific Fuel Consumption} = \frac{\text{Energy Absorbed to Produce 1000 lb Steam}}{\text{Thermal Efficiency}}$$

The energy absorbed to produce 1000 lb steam is the difference between the specific enthalpies of steam and water times 1000 lb, or

1000 x (1193.8 – 107.0) = 1000 x 1086.8 = 1,086,800 Btu

Therefore, SFC = 1,086,800/82% = 1.325 MMBtu/1000 lb steam

Direct emissions are then calculated as:

GHG_D = 117 lb-$CO_{2(e)}$/MMBtu x 1.325 MMBtu/1000 lb steam
= 155.0 lb/1000 lb steam

<u>Indirect Emissions</u>

Indirect emissions produced from operation of electric motors are determined by the following:

GHG (electric motor) = Electric Utility GHG Emission Factor x kWh consumed

To determine kWh consumption per 1000 lb steam produced it is necessary to first determine the Bhp requirement for the gas compression operation by the combustion air blower. Specific brake horsepower requirement by the combustion air fan is calculated from the following equation for adiabatic compression of an ideal gas[3]:

Bhp-hr/1000 lb steam = (T/520) x (0.001072M/n*E*) x $[(p_2/p_1)^n-1]$

Gas temperature is based on the mix temperature of fresh combustion air (at 68 K) plus 30 % FGR (at 460 F):

T = (1 x 68 + 0.3 x 460)/1.3 = 158 ^{o}F or 618 ^{o}R

M = scf flue gas per 1000 lb steam
= 12,590 scf flue gas/MMbtu x 1.325 MMBtu/1000 lb steam
= 16,682 scf flue gas/1000 lb steam

n = 0.2857 (typical for diatomic gases)
E = efficiency = 60%
p_1 = atmospheric pressure = 407 “WC
p_2 = atmospheric pressure + pressure drop
= 407.0 + 33.8 = 440.8 “WC

Substituting the given values into the equation:

Bhp-hr/1000 lb steam = 2.85

Specific brake horsepower requirement for the boiler feedwater pump is calculated by the following equation (see reference 3, page 342):
Bhp/1000 lb steam = (G x P)/(102,780 x *E*)

G = gallons pumped per 1000 lb steam = 131 gallons

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[3] See: Clarke, Loyal and Robert Davidson, Manual for Process Engineering Calculations, 2nd Edition, McGraw-Hill, New York, 1975, p.360.

P = pump differential pressure in psi = 200 psi
E = 60%

Bhp/1000 lb steam = (131 x 200)/(102,780 x 0.6) = 0.42 bhp-hr/1000 lb

Combined energy for compression and pumping is therefore:

2.85 (compression) + 0.42 (pumping) = 3.27 bhp-hr/1000 lb steam

Converting to kWh based on an 87% efficient electric motors and a conversion factor of 0.7457 kWh/bhp:

= (3.27 x 0.7457)/87% = 2.8 kWh/1000 lb steam

GHG_I = GHG (electric motors)
= 0.524 lb-$CO_{2(e)}$/kWh x 2.80 kWh/1000 lb steam
= 1.47 lb $CO_{2(e)}$ per 1000 lb steam production

The Baseline Emission Factor is the sum of the direct and the indirect emissions:

BEF = *155.0 + 1.5 = 156.5 lb-* $CO_{2(e)}$*/ton*

STEP 2. Technologically Feasible GHG Emission Control Measures

A. Analysis of Potential Control Measures

The following findings and/or considerations are applicable to this class and category:

<u>Use of Economizers on Boilers</u>

Boilers without economizers are limited to operating with a stack temperature which must exceed the saturated steam temperature for the given pressure level of the boiler, significantly limiting potential thermal efficiency. The margin between flue gas temperature and the steam temperature may vary from 50-100 ^oF for firetube boilers and up to 250 ^oF for watertube boilers resulting in stack temperatures ranging from approximately 375 ^oF for a 75 psig firetube boiler up to 550 ^oF for a 125 psig watertube boiler with approximate efficiencies of 82% and 77% respectively.
An economizer is essentially additional heat transfer surface which serves to recover heat from the boiler exhaust by transferring it to the boiler feedwater or to other low temperature heat utilization in the facility. The use of economizers for recovery of thermal energy from boiler flue gases is a

common practice in both commercial and industrial boiler installations, including the use of two-stage economizers which serve to not only heat the deaerated water flowing directly to the boiler but to also pre-heat returned condensate and fresh makeup water upstream of the deaerator. Economizer designs based on an approach of 20 ^{o}F or less (temperature differential between flue gas leaving the economizer section and the water entering the section) are also achieved-in-practice for high-performance economizer design, however, in practice, economizer approach temperatures less than 20 ^{o}F are rare due to the rapidly decreasing incremental heat recovery for each added increment of heat exchange surface as required to further reduce the approach temperature.

Assuming no other heat sinks are available in a particular facility, the potential thermal efficiency of a particular boiler equipped with an economizer is largely a function of the temperature of the boiler water supply temperature (the combined temperature of returned condensate and makeup water). This water temperature effectively limits the extent to which heat may be recovered from the stack gases using an economizer. When a boiler operates with cold return water temperatures (such as a once-through boiler with 60 ^{o}F return water), condensing economizer operation becomes possible wherein the stack temperature is lowered below the dew point of the flue gas. In this case, significant additional heat recovery becomes possible due to the recovery of the latent heat of vaporization associated with the condensed water and the boiler thermal efficiency can exceed 95% for boilers designed with current state of the art economizers. This level of performance is considered to be achieved-in-practice but can only be achieved in special cases and represents the limiting maximum efficiency for a performance standard.

Likewise, when return water temperatures are significantly higher (such as when a facility recovers a large portion of hot condensate and returns it to the boiler), potential boiler thermal efficiency is significantly reduced unless other low temperature heat uses are available in the facility. For example, a boiler equipped with a state-of-the-art economizer system may only be capable of achieving 85-86% thermal efficiency when return water temperatures exceed 200 ^{o}F. However, it is important to recognize that the collection and return of hot condensate is an energy saving measure in itself which can offset the reduction in thermal efficiency for the boiler.

Based on the above discussion, it is apparent that specification of a BPS control measure based on a single required thermal efficiency to be achieved with an economizer is problematic since the theoretical potential thermal efficiency may vary significantly depending upon the return water temperature to the boiler. To address this issue, the District proposes to establish an economizer design-based control measure by specifying a required temperature approach of the economizer. A standard based on approach temperature can be applied to a wide range of boilers which exhibit a wide variation in return water temperature and, when established at a maximum value of 20 ^oF, the standard will ensure achieved state-of-the-art thermal performance for the class and category.

The District's analysis of this control measure has included the assumption that a boiler operation in this class and category normally includes a deaerator operating at approximately 5 psig for removal of dissolved oxygen from the boiler feedwater prior to entering the boiler (for purposes of corrosion control in the boiler). The deaerator is essentially a feedwater heater using steam to heat the boiler return temperature to a saturated condition at the deaerator pressure. This results in a boiler feedwater temperature from the deaerator to the boiler of approximately 227 ^oF (note that the assumption of a deaerator is a conservative assumption since the absence of a deaerator would imply a colder water temperature, allowing additional opportunity for heat recovery). The District's analysis indicates that at boiler pressures of 75 psig and above, operation of an economizer which heats the 227 ^oF deaerated feedwater to the maximum extent possible based on a 20 ^oF economizer approach, will yield substantial improvement in boiler thermal efficiency (in the range of 4-10 percentage points for overall boiler efficiency depending upon the specifics of the application).

The specified economizer operation with a 20 ^oF approach may problematic in a small number of boilers which exhibit higher temperature margins between flue gas temperature and steam saturation temperature, resulting in excessive heating of the boiler feedwater in the economizer and "steaming" at the economizer outlet (general practice is to maintain water temperature at the economizer outlet at least 30 ^oF below drum saturation temperature to avoid mechanical problems). To address this potential issue, the District's proposed BPS determination has included an allowance for relaxation of the 20 ^oF approach specification to the extent that is required to maintain a 30 ^oF difference between the drum temperature and the economizer outlet temperature.

When a deaerator or other feedwater heater is used and the temperature of the combined boiler water supply (going to the feedwater heater in this case) is low enough, the use of a 2nd stage economizer is a common practice to further enhance the energy recovery. See Appendix 1 for illustration of a typical two-stage economizer system (note that the District is not endorsing the specific manufacturer presented in Appendix 4 (the document is presented only as a typical example of the proposed control measure and other manufacturers are invited to submit designs). This practice addresses potential energy recovery that is available when cold boiler water is heated with steam in the feedwater heater prior to entering the traditional boiler economizer downstream of the heater. The District's analysis of this case indicates that when the combined boiler water supply is 160 ^{o}F or less, an additional improvement of at least approximately 2 percentage points in boiler thermal efficiency can be achieved with a 2nd stage economizer. Establishing a 160 ^{o}F threshold for requirement of a 2nd stage economizer provides flexibility for a facility to either achieve additional efficiencies in recovery of hot condensate on the facility side, avoiding installation of the 2nd stage of the economizer, or to elect to install the 2nd stage unit where hot condensate recovery is not possible or is cost prohibitive. The District proposes to restrict the application of this standard to boilers rated 20 MMBtu per hour and larger since two stage systems are not typically installed on small boilers and they are expected to be cost prohibitive in small systems. In addition, units rated less than 20 MMBtu/hr represent less than 20 % of all units permitted by the District.

The District's analysis for the use of economizers has been based on a conservative approach which ignores other potential heat recovery schemes which may be feasible (and more cost effective) depending upon the site specific characteristics of the facility. Therefore, specification of an economizer design as BPS will necessarily include an allowance to use an alternate design which provides an equivalent thermal efficiency for the boiler operation.

<u>Air Pre-heaters</u>

Heating combustion air can raise boiler efficiency about 1% for every 40 ^{o}F increase in combustion air temperature. The most common way to preheat the air is with a heat exchanger on the flue exhaust. Such a unit produces a result similar to an economizer in that energy in the boiler exhaust is recovered and returned to the boiler to improve thermal efficiency. Regenerative and recuperative designs are available as well as designs employing boiler feedwater as an intermediary heat transfer medium to transfer heat between the flue gas and air streams. Air pre-heaters are common on large utility boilers (particularly solid fuel-fired boilers) but are rarely used on industrial boilers due to cost and complexity. When compared to economizers, they are generally more expensive per unit of energy recovery, require more space, and consume additional electrical energy to move the combustion air through the heat exchanger. In addition, use of heated combustion air is problematic due potential impacts on NO_x emission from the unit. In general, where other low temperature heat receptors are available such as the heating of boiler feedwater, the economizer is the more economical approach for increasing thermal efficiency of the unit while avoiding potential increases in NO_x emissions associated with air pre-heaters. Due to potential increases in NOx emissions, air pre-heaters are determined to not be technologically feasible for general designation as BPS.

Use of Oxygen Trim Systems

All combustion processes require the correct measure of oxygen; too much or too little can cause undesirable effects. However, in actual operations the error is almost always intentionally on the high-side (too much oxygen) because operating with too little air results in carbon monoxide formation, sooting and a potential for explosion if the accumulated soot and other non-combusted fuel suddenly get enough oxygen to rapidly burn. The primary effect when operating on the high side is only a reduction in efficiency.

When boiler burners are manually tuned on a periodic basis, they are typically adjusted to a conservatively high excess air value, almost always greater than 3% excess oxygen which is about 15% excess air (air in excess of that required for stoichiometric combustion of the fuel). Tuning to a conservatively high value ensures that the operation will remain stable and safe over the entire operating range of the boiler. From an efficiency standpoint, the excess O_2 means there is more air in the combustion stream than there needs to be. The amount of excess O_2 is approximately proportional to the efficiency lost; that is, 3% excess O_2 means approximately a 3% efficiency drop for the boiler. In addition, incremental electrical energy consumption is required by the combustion air blower to handle higher excess air, leading to additional indirect GHG emissions.

An oxygen trim system typically consists of an O_2 analyzer, boiler pressure or temperature sensor, a controller, and actuators on the combustion air damper and the fuel control valve. Such a system will be capable of implementing various control strategies which will maintain optimum excess air levels over the complete boiler operating range, ensuring that only the necessary amount of excess air is used. For natural gas combustion at full firing rate, operating with an oxygen concentration of 2% O_2 with an O_2 trim system is considered to be an achievable value which will provide significant energy savings when compared to a periodic manual adjustment of excess air.

It is important to note that operation with high excess air is a feature of some ultra-low NOx burners which utilize high excess air to control peak combustion temperature. It may not be feasible to limit excess air in lower pressure boilers that are subject to the District's current NOx regulations since the lower stack temperatures on these units will rule out the use of selective catalytic reduction as an alternative to ultra low NOx burners operating with high excess air. In addition, use of SCR on boilers rated less than 20 MMBtu/hour is not considered to be achieved in practice due to potential technical and safety issues with storage and handling of ammonia (particularly for facilities such as commercial buildings and schools) as well as practicality with respect to cost of installation and operation of SCR relative to boiler size.

Limiting Flue Gas Recirculation (FGR)

FGR is utilized to control combustion temperature at the burner with recirculation rates up to 40% in some ultra low NOx applications. This recirculation has a negative impact on boiler performance similar to that of excess air and requires substantial fan horsepower to operate. Limiting FGR rates will provide substantial energy savings, however, limited FGR can be considered to be achieved in practice only for boilers above 125 psig operating pressure and 20 MMBtu/hr rated firing capacity per the rationale presented above.

Use of Premium Efficiency Motors with Speed Control

An electric motor efficiency standard is published by the National Electrical Manufacturers Association (NEMA) which is identified as the “NEMA Premium Efficiency Electric Motors Program”. For large motors, the NEMA premium efficiency motor provides a gain of approximately 5-8 percentage points in motor efficiency when compared to a standard efficiency motor. The NEMA specification covers motors up to 500 horsepower and motors meeting this specification are in common use and are available from most major electric motor manufacturers.

Control of a fan or pump operation by use of a variable speed electric motor provide substantial energy savings when compared to a fan or pump which is operated at a fixed speed and controlled by throttling the discharge flow. The most common and economical variable speed drive is the variable frequency drive (VFD) which has become commonly available in the last decade and is typical for new boiler fan and pump applications. The VFD provides especially significant energy savings when a boiler is operated at substantial turndown rations which can result in throttling away more than half the rated energy output of the motor.

B. Listing of Technologically Feasible Control Measures

For the specific equipment or operation being proposed, all technologically feasible GHG emissions reduction measures are listed, including equipment selection, design elements and best management practices, that do not result in an increase in criteria pollutant emissions compared to the proposed equipment or operation.

Table 1
Technologically Feasible GHG Control Measures for *Gaseous Fuel-Fired Boilers with Rated Steam Pressure 75 psig and Greater*

Control Measure	Qualifications
1. The boiler shall have a minimum thermal efficiency of 95% at the maximum firing rate or, alternatively, shall be 1) equipped with an economizer designed at maximum firing rate which will either reduce the temperature of the economizer flue gas outlet to a value no greater than 20 ^{o}F above the temperature of the inlet water to the economizer or will heat the water to a temperature which is 30 ^{o}F less than the steam temperature at the steam drum , or 2) shall be equipped with other economizer and/or heat recovery options which will collectively provide an equivalent energy recovery from the boiler	*An economizer directly increases boiler efficiency by adding heat transfer surface to the unit for recovery of energy from the flue gas. This measure 1) is achieved in practice and 2) incorporates best practical performance for economizer design*
2. . For boilers with a rated firing duty of 20 MMBtu/hr or greater, when the boiler feedwater is to be deaerated or otherwise preheated with steam and the temperature of the water supply to the deaerator or steam heater is equal to or less than 160 ^{o}F (combined makeup and recovered condensate), the boiler shall include a 2nd stage economizer to heat the feedwater flowing to the deaerator/heater or shall incorporate other economizer/heat recovery options which will collectively provide an equivalent energy recovery from the boiler. The second stage economizer design shall be based on reducing the temperature of the 2nd stage economizer flue gas outlet to a value no greater than 20 ^{o}F above the temperature of the inlet water to the 2nd stage economizer when the boiler is operating at the maximum firing rate	*A 2nd stage economizer provides an additional direct increase in boiler efficiency by adding more heat transfer surface to the unit for recovery of energy from the flue gas. This measure 1) is achieved in practice, 2) provides best practical performance for economizer design, 3) establishes a temperature threshold for incorporation of the measure which minimizes steam pre-heating of boiler feedwater and incentivizes recovery of hot condensate (alternate energy efficiency improvement).*
3. Electric motors driving combustion air fans, induced draft fans and boiler feedwater pumps shall have an efficiency meeting the standards of the National Electrical Manufacturer's Association (NEMA) for "premium efficiency" motors and shall each be operated with a variable frequency speed control or equivalent for control of flow through the fan or pump	*Use of premium efficiency motors with variable speed drives significantly reduces electric power consumption by the boiler operation, particularly during periods of reduced-rate operation. This measure 1) is achieved in practice, 2) is currently a common specification for new boilers and boiler retrofits, 3) is best practical performance for minimizing indirect GHG emissions from electric motors associated with the boiler operation.*

4. For boilers with rated fired duty in excess of 20 MMBtu/hr and a rated steam pressure of 125 psig or greater, the boiler shall be 1) equipped with an O_2 trim system which will control oxygen content of the stack gases to a maximum of 2 volume % dry basis at maximum firing and 2) shall limit the recirculation of flue gas to a value not exceeding 10 percent of total flue gas volume.	*This measure increases boiler efficiency by minimizing efficiency losses associated with high excess air operation and/or operation with high flue gas recirculation rates. Boilers in this pressure and size classification are characterized by stack temperatures exceeding 400 ^oF and are subject to a 5 ppmv NOx limit per District Rule 4320. These units are commonly specified with selective catalytic reduction (SCR) for NOx control to 5 ppmv since the higher stack temperature is suitable for SCR catalyst operation. Current ultra low NOx burner operation as an alternative to SCR (if feasible) is expected to require FGR rates in excess of 40% as well as operation with high excess air rates due to stability issues. This operation would result in significantly higher GHG emissions when compared to an SCR system.*

All of the control measures identified above are equipped with control equipment for criteria pollutants which meets current regulatory requirements. None of the identified control measures would result in an increase in emissions of criteria pollutants.

STEP 3. Identify all Achieved-in-Practice GHG Emission Control Measures

For all technologically feasible GHG emission reduction measures, all GHG reduction measures determined to be Achieved-in-Practice are identified. Achieved-in-Practice is defined as any equipment, technology, practice or operation available in the United States that has been installed and operated or used at a commercial or stationary source site for a reasonable period of time sufficient to demonstrate that the equipment, the technology, the practice or the operation is reliable when operated in a manner that is typical for the process. In determining whether equipment, technology, practice or operation is Achieved-in-Practice, the District will consider the extent to which grants, incentives or other financial subsidies influence the economic feasibility of its use.

The following findings or considerations are applicable to this class and category:

The District reviewed actual project profiles for actual recent new boiler installations provided by boiler designers and manufacturers as well as current commercially available designs offered by boiler manufacturers. The review indicated the following with respect to this class and category:

- Fully condensing boilers exceeding 95% thermal efficiency, when operated as once-through boilers with cold makeup water, are achieved in practice and are readily available from a number of manufacturers.

- Economizer installations in general are commonplace for new boiler installations.

- Two-stage economizer designs with condensing 2nd stage are achieved in practice and are available as standard design packages. See Appendix 1 which presents a current 2-stage design package offered by a major boiler manufacturer (note that the District is not endorsing the specific manufacturer presented in Appendix 4; the document is presented only as a typical example of the proposed control measure and District invites other manufacturers to submit examples).

- Per statements by boiler and economizer manufacturers, a 20 ^{o}F approach design criteria represents the best practical performance for energy recovery with an economizer.

- Per statements by manufacturers, premium efficiency motors with variable frequency drives are essentially current standard practice for new boiler installations.

- Per project profiles for actual recent projects for boilers above 125 psig and above 20 MMBtu/hr, low excess air operation with zero FGR, combined with a high efficiency economizer system, are achieved in practice. See Appendix 5 for an example profile of a recent boiler project incorporating these concepts (Note that the District is not endorsing the manufacturer presented in Appendix 2; the document is presented only as an example of achieved in practice application of the proposed control measures. Other manufacturers of similar equipment exist and the District invites such manufacturers to submit similar application profiles).

As noted in Table 1 and as discussed above, all technologically feasible control measures listed in Table 1 are deemed to be Achieved in Practice. Since all four of the achieved-in-practice measures identified are independent of each other, concurrent implementation of all four measures results in a strictly additive benefit (none of the measures are mutually exclusive). Therefore, all identified control measures are considered to be single measure in effect. Since there are no other mutually exclusive measures identified, there is in effect a single achieved in practice control measure identified. and the District proposes to deem the concurrent implementation of all four identified achieved-in-practice control measures as BPS for this class and category.

STEP 4. Quantify the Potential GHG Emission and Percent Reduction for Each Identified Achieved-in-Practice GHG Emission Control Measure

For each Achieved-in-Practice GHG emission reduction measure identified:

a. Quantify the potential GHG emissions per unit of activity (G_a)
b. Express the potential GHG emission reduction as a percent (G_p) of Baseline GHG emissions factor per unit of activity (BEF)

As stated above, there is a single identified achieved in practice control measure for this class and category. Therefore, the GHG emission quantification will be presented as a single value based on the additive contribution of each individual measure incorporated into the overall control measure.

A. Basis and Assumptions:

As previously stated, historical demand for boilers in the range of 50 to 100 psig operating pressure has been very small and for boilers rated 125 psig and above, the most typical unit supplied has been in the range of 125 to 150 psig with an average closer to 125 psig. Therefore, consistent with the approach taken for quantification of the Baseline Emission Factor, a 125 psig boiler with a combined feedwater temperature of 140 ^{o}F has been selected to represent the average new unit to be proposed in this class and category. Additionally, since a review of the District's permit database indicates that the average boiler size currently under permit exceeds 30 MMBtu/hour and that boilers equal to or greater than 20 MMBtu/hr represent over 80% of the total fired duty of all units permitted by the District, the representative boiler will be assumed to have a rated firing capacity greater than 20 MMBtu/hr.

- All direct GHG emissions are produced due to combustion of natural gas in this unit.
- Application of the proposed BPS to this unit results in a requirement to install a 2-stage economizer with a stack temperature no greater than 20 ^{o}F above the average combined water temperature. Therefore, the stack temperature would be 160 ^{o}F at the design case which is assumed to be maximum firing rate. Since the unit exceeds 20 MMBtu/hr, stack O_2 concentration is limited to 2% and FGR is limited to 10%. Assuming convection/radiation losses from the boiler amounting to 0.5% of the firing rate, the District's thermal/combustion analysis indicates a thermal efficiency of approximately 87.7% for this unit.

- Combustion of 1 MMBtu of natural gas produces 11,277 scf of flue gas including moisture and sufficient excess air to result in an oxygen concentration of 2.0% per District's analysis.
- The enthalpy of 125 psig steam is 1193.8 Btu/lb (per steam tables).
- The temperature of the combined feed water to the boiler plant (combined flow of returned condensate and makeup water to the boiler upstream of any steam pre-heaters) is 140 ^{o}F.
- The enthalpy of 140 ^{o}F water is 107.0 Btu/lb (per steam tables).
- GHG emissions are stated as "CO_2 equivalents" ($CO_{2(e)}$) which includes the global warming potential of methane and nitrous oxide emissions associated with gaseous fuel combustion.
- The GHG emission factor for natural gas combustion is 117 lb-$CO_{2(e)}$/MMBtu per CCAR document[4].
- Indirect emissions are produced due to operation of the combustion air fan and the boiler feed water pump.
- Static efficiency of the combustion air fan is assumed to be 60%.
- Flue gas side pressure drop for the boiler is assumed to be 20 inches water column when operating without FGR plus an allowance for additional dynamic loss due to FGR which is assumed to be proportional to the square of the mass flow. For an FGR rate of 10 %, pressure drop is Base Pressure Drop x (1 + $\%_{FGR}$)^2 = 20 x 1.1^2 = 24.2 inches W.C..
- Differential operating pressure for the boiler feed water pump, operating with a VFD, is assumed as follows:

	psi
Steam Drum Pressure	125
Allowance for Relief Valve	0
Control Valve	0
Dynamic Losses (economizer & other)	10
Less Deaerator Pressure	-5
Total	130

- The boiler feedwater pump has a capacity requirement of 5% over the net steam rate to allow for blowdown and deaerator steam. The pump therefore delivers 1050 lb water at a density of 8 lb/gallon (131 gallons) per 1000 gallons of steam produced.
- Hydraulic efficiency of the feed water pump is assumed to be 60%.
- Electric motor efficiency is estimated at 95% for a premium efficiency electric motor.
- A 30% reduction in net specific electric power consumption is attributed to use of VFD during turndown periods.
- Indirect emissions from electric power consumption are calculated based on the current PG&E electric power generation factor of 0.524 lb-$CO_{2(e)}$ per kWh

[4] California Climate Change Action Registry (CCAR), Version 3.1, January, 2009 (Appendix C, Tables C.7 and C.8)

B. Calculation of Potential GHG Emissions per Unit of Activity (G_a):

G_a is the sum of the direct (GHG_D) and indirect (GHG_I) emissions (per unit of activity):

$G_a = GHG_D + GHG_I$

Direct Emissions:

$GHG_D = E_f \times SFC$

E_f = 117 lb-$CO_{2(e)}$ per MMBtu of natural gas

$$SFC = \text{Specific Fuel Consumption} = \frac{\text{Energy Absorbed to Produce 1000 lb Steam}}{\text{Thermal Efficiency}}$$

Energy absorbed to produce 1000 lb steam is the difference between the specific enthalpies of steam and water times 1000 lb, or

1000 x (1193.8 – 107.0) = 1000 x 1086.8 = 1,086,800 Btu

Therefore, SFC = 1,086,800/87.7% = 1.239 MMBtu/1000 lb steam

Direct emissions are then calculated as:

GHG_D = 117 lb-$CO_{2(e)}$/MMBtu x 1.239 MMBtu/1000 lb steam
= 145.0 lb-$CO_{2(e)}$/1000 lb steam

Indirect Emissions

Indirect emissions produced from operation of electric motors are determined by the following:

GHG (electric motor) = Electric Utility GHG Emission Factor x kWh consumed

To determine kWh consumption per 1000 lb steam produced it is necessary to first determine the Bhp requirement for the gas compression operation by the combustion air blower. Specific brake horsepower requirement by the combustion air fan is calculated from the following equation for adiabatic compression of an ideal gas[5]:

[5] See: Clarke, Loyal and Robert Davidson, Manual for Process Engineering Calculations, 2nd Edition, McGraw-Hill, New York, 1975, p.360.

$$\text{Bhp-hr/1000 lb steam} = (T/520) \times (0.001072M/nE) \times [(p_2/p_1)^n - 1]$$

Gas temperature is based on the mix temperature of fresh combustion air (at 68 K) plus 10 % FGR (at 460 F):

$T = (1 \times 68 + 0.1 \times 460)/1.1 = 104\ ^oF$ or $564\ ^oR$

M	=	scf flue gas per 1000 lb steam
	=	11,277 scf flue gas/MMbtu x 1.239 MMBtu/1000 lb steam
	=	13,972 scf flue gas/1000 lb steam
n	=	0.2857 (typical for diatomic gases)
E	=	efficiency = 60%
p_1	=	atmospheric pressure = 407 “WC (14.7 psia)
p_2	=	atmospheric pressure + pressure drop
	=	407.0 + 24.2 = 431.2 “WC

Substituting the given values into the equation yields a value of 1.58 Bhp-hr/1000 lb steam. Applying a 20% reduction to account for the use of a VFD:

Combustion air fan specific energy consumption = (1-20%) x 1.58

= 1.26 Bhp-hr/1000 lb steam

Specific brake horsepower requirement for the boiler feedwater pump is calculated by the following equation (see reference 3, page 342):

$$\text{Bhp/1000 lb steam} = (G \times P)/(102{,}780 \times E)$$

G = gallons pumped per 1000 lb steam = 131 gallons
P = pump differential pressure in psi = 130 psi
E = 60%

Substituting the given values into the equation yields a value of 0.28 Bhp-hr/1000 lb steam. Applying a 20% reduction to account for the use of a VFD:

Feedwater pump specific energy consumption = (1-20%) x 0.28

= 0.22 Bhp-hr/1000 lb steam

Combined energy for compression and pumping is therefore:

1.26 (compression) + 0.22 (pumping) = 1.48 bhp-hr/1000 lb steam

Converting to kWh based on an 95% efficient electric motors and a conversion factor of 0.7457 kWh/bhp:

= (1.48 x 0.7457)/95% = 1.16 kWh/1000 lb steam

GHG_I = GHG (electric motors)
=0.524 lb- $CO_{2(e)}$/kWh x 1.16 kWh/1000 lb steam
= 0.61 lb $CO_{2(e)}$ per 1000 lb steam production

GHG Emissions per Unit of Activity is then calculated as:

G_a = *145.0 + 0.6 = 145.6 lb-* $CO_{2(e)}$*/ton*

C. Calculation of Potential GHG Emission Reduction as a Percentage of the Baseline Emission Factor (G_p):

G_p = (BEF - G_a) / BEF = (156.5 – 145.6)/156.5 = 7.0%

STEP 5. Rank all Achieved-in-Practice GHG emission reduction measures by order of % GHG emissions reduction

Since only a single achieved in practice control measure is identified, no ranking is necessary.

STEP 6. Establish the Best Performance Standard (BPS) for this Class and Category

For Stationary Source Projects for which the District must issue permits, Best Performance Standard is – “For a specific Class and Category, the most effective, District approved, Achieved-In-Practice means of reducing or limiting GHG emissions from a GHG emissions source, that is also economically feasible per the definition of achieved-in-practice. BPS includes equipment type, equipment design, and operational and maintenance practices for the identified service, operation, or emissions unit class and category”.

Based on the definition above, Best Performance Standard (BPS) for this class and category is determined as:

Best Performance Standard for Gaseous Fuel-Fired Boilers with Rated Steam Pressure 75 psig and Greater

See BPS Specification on page 1

STEP 7. Eliminate All Other Achieved-in-Practice Options from Consideration as Best Performance Standard

The following Achieved-in-Practice GHG control measures, identified in Section II.4 and ranked in Table 3 of Section II.5 are specifically eliminated from consideration as Best Performance Standard since they have GHG control efficiencies which are less than that of the selected Best Performance Standard as stated in Section II.6:

No other Achieved-in-Practice options were identified.

V. Appendices

Appendix 1	Initial Public Process
Appendix 2	Public Review Process
Appendix 3	Reserved for Public Comments Received and District Responses
Appendix 4	Typical 2-stage condensing economizer
Appendix 5	Project Profile

Appendix 1
Initial Public Process

Appendix 2
Public Review Process

Appendix 3

Reserved for Public Comments Received and District Responses

Appendix 4
Typical 2-stage condensing economizer

Appendix 5
Project Profile