San Joaquin Valley
Unified Air Pollution Control District

Best Performance Standard (BPS) x.x.xx

<table>
<tr><td>Class</td><td>Gaseous Fuel-Fired Boilers</td></tr>
<tr><td>Category</td><td>New Boilers with Operating Steam Pressure 75 psig and Greater, Fired Exclusively on Natural Gas or LPG</td></tr>
<tr><td rowspan="2">Best Performance Standard</td><td>Applicability Note: Boilers with operating steam pressure greater than 75 psig but fired with gaseous fuels other than natural gas or LPG (either exclusively or mixed with natural gas or LPG) and which meet the following standards shall be considered to meet BPS for their respective category.</td></tr>
<tr><td>Boilers meeting this Best Performance Standard must comply with all four elements of this BPS (items 1, 2, 3 and 4 listed below) where applicable.

1. The boiler shall be either equipped with an economizer system meeting the following design criteria or shall be equipped with an approved alternate heat recovery system which will collectively provide heat recovery from the boiler flue gas which is equivalent:

A. Except for boilers subject to the requirements of items B or C below, the economizer system shall consist of, as a minimum, a single stage economizer section which will recover energy from the boiler flue gas by heat exchange with the boiler feed water. The economizer system shall be designed at maximum boiler firing rate to either 1) reduce the temperature of the economizer flue gas outlet to a value no greater than 20°F above the temperature of the boiler feed water at maximum firing rate, or 2) heat the boiler feed water to a temperature which is no less than 30°F below the steam temperature at the steam drum, or 3) reduce the final temperature of the boiler's flue gas to a temperature no greater than 200°F.

Note: For purposes of this BPS, feedwater temperature is defined as the temperature of the water stream delivered to the boiler from the deaerator or feedwater tank.

B. For boilers with a feedwater temperature greater than or equal to T_s - 50, where T_s is the saturation temperature of steam at the steam separator pressure in °F, the steam generator may be designed, in lieu of the requirements of item A above, to achieve a flue gas temperature no greater than the steam saturation temperature (°F at the steam drum operating pressure) plus 100°F.

C. For boilers with rated capacity in excess of 20 MMBtu/hr which have a average water supply temperature which is equal to or less than 150°F, the boiler shall equipped with an economizer designed to reduce the temperature of the flue gas outlet to a value no greater than 50°F above the water supply temperature when the boiler is operating at maximum firing rate.

Note: For purposes of this BPS, water supply temperature is defined as the weighted average temperature of the combined makeup water and the recovered condensate delivered to the boiler upstream of any deaerator or other feedwater preheater but after benefit of any other heat recovery operations which recover waste heat from the boiler by transfer to the boiler water supply (such as boiler blowdown heat recovery).</td></tr>
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<tr><td>Best Performance Standard (continued)</td><td colspan="2">

2. Electric motors driving combustion air fans or induced draft fans 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 speed control or equivalent for control of flow through the fan.

3. For boilers with rated fired duty in excess of 20 MMBtu/hr and an operating steam pressure of 125 psig or greater, the boiler shall be 1) equipped with an O_2 trim system and be designed to control oxygen content of the stack gases to a maximum of 3 volume % dry basis except during any period where the rate of fuel consumption by the boiler is less than 20% of maximum rated firing and 2) shall be designed to limit the recirculation of flue gas to a value not exceeding 10 percent of total flue gas volume while meeting the applicable requirements for control of NOx emissions from the boiler.

4. For boilers with rated fired duty in excess of 20 MMBtu/hr and a boiler blowdown rate exceeding 8 % of steam production, the boiler shall be equipped with: 1) an automatic boiler blowdown control system which will minimize boiler blowdown while controlling dissolved solids in the boiler water at an optimum level and 2) a flash steam recovery system which will recover flash steam from the blowdown pressure reduction and utilize it for feedwater heating in the deaerator or feedwater heater.
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<tr><td colspan="2">Percentage Achieved GHG Emission Reduction Relative to Baseline Emissions</td><td>6.9%</td></tr>
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District Project Number	C-1100388
Evaluating Engineer	Dennis Roberts, P.E.
Lead Engineer	Martin Keast
Public Notice of Intent Date	April 8, 2010
Public Notice #1 Date (Draft #1)	April 30, 2010
Public Notice #2 Date (Draft #2)	August 30, 2010
Public Notice #2 Closing Date	September 27, 2010
Determination Effective Date	January 19, 2011

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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 polic*y: 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.

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 *New Boilers with Operating Steam Pressure 75 psig and Greater, Fired Exclusively on Natural Gas or LPG* 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, <u>Addressing Greenhouse Gas Emissions under the California Environmental Quality Act</u>. A summary of the specific implementation of the phased BPS development process for this specific determination is as follows:

Table 1
BPS Development Process Phases for *New Boilers with Operating Steam Pressure 75 psig and Greater, Fired Exclusively on Natural Gas or LPG*

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 C. Comment received during the initial public process with District's responses are attached a Appendix D.
2	BPS Development	N/A	See Section III of this evaluation document.
3a	1st Public Review	04/08/10	The District's draft BPS determination was posted on the date indicated.
4a	1st Public Comments	05/06/10	Public Comments received during the 1st Public Review with District's responses are attached as Appendix E.
3b	2nd Public Review	8/30/10	The District's 2nd draft BPS determination was posted on the date indicated..
4b	2nd Public Comments	9/27/10	Public Comments received during the 2nd Public Review with District's responses are attached as Appendix F.

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.

  New Boilers with Operating Steam Pressure 75 psig and Greater, Fired Exclusively on Natural Gas or LPG 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°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+ °F prior to delivery to the boiler. Given a stack temperature exceeding 320°F and a feedwater temperature of 225°F, the District's analysis indicates that a boiler operating with these parameters can accommodate installation of an economizer designed for a 20°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 Public Notice of Intent

Prior to developing the development of BPS for this class and category, the District published a Notice of Intent. Public notification of the District's intent to develop BPS for this class and category was sent on April 1, 2010 to individuals registered with the CCAP list server. The District's notification is attached as Appendix C.

Comments received during the initial public outreach are presented in Appendix D. These comments have been used in the development of this BPS as presented below.

V. 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 *New Boilers with Operating Steam Pressure 75 psig and Greater, Fired Exclusively on Natural Gas or LPG*, 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 driver, not equipped with speed control, for the combustion air fan*
- *Boiler blowdown rate = 8% of steam rate, operating with a flash steam recovery system*

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:

- 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 30 ppmv NOx emission level (consistent with the District's prohibitory rule for boilers during the Baseline Period).

A conventional, single speed electric motor driver was assumed for the combustion air fan 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.

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

A boiler blowdown rate of 8% of the steam rate was assumed based on current typical boiler operation in the range of 5-8%[2]. A flash steam recovery system, which serves to recover flash steam from the blowbown operation for use in the deaerator) was assumed to be included in the baseline facility since this is has long been a commonplace operation in steam plants.

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% (boiler absorbed duty ÷ boiler fired duty)
- Convection/radiation loss from the boiler is assumed to be 0.5% of fuel firing.
- Vent loss from the deaerator is assumed to be 5% of total DA steam.
- It is assumed that 50% recovery of condensate is achieved at a temperature of 200 ^oF. The balance of the boiler water is makeup at 60 ^oF. This results in an average 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) of 130 ^oF.
- 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.
- Based upon a boiler heat and mass balance for the given conditions, the following quantities are applicable:
  - Net steam production is 736 lb/MMBtu fired or a Specific Fuel Consumption (SFC) of 1,000,000/736 = 1,358 Btu/lb steam
  - Flue gas rate is 12,586 scf/MMbtu fired
  - Combustion air rate is 12,164 scf/MMBtu fired
- The GHG emission factor for natural gas combustion is 117 lb-CO_2(e)/MMBtu per CCAR document[3].
- Indirect emissions produced due to operation of the combustion air fan will be considered. Indirect emissions from other electric motors associated with the boiler are not considered significant. .
- Static efficiency of the combustion air fan is assumed to be 60%.
- Flue gas side pressure drop for the burner + boiler is assumed to be 20 inches water column when operating without FGR with a flue gas rate of 12,586 scf/MMBtu (12 "WC for burner, 8 "WC for boiler).
- An allowance for additional dynamic loss in the boiler due to FGR will be added which is assumed to be proportional to the square of the mass flow. For an FGR rate of 30 %, flow through the boiler is estimated as: 12,586 x 1.3 = 16,362 scf/MMBtu fired

[2] U.S. Department of Energy, Energy Efficiency and Renewable Energy, Steam Tip Sheet #9, January, 2006.
[3] California Climate Change Action Registry (CCAR), Version 3.1, January, 2009 (Appendix C, Tables C.7 and C.8)

Pressure drop through the system is then calculated as:

Burner		12.0 " WC
Boiler	8" WC x $(16,362/12,586)^2$ =	13.5
Total		25.5

- 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.

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-CO_2 equivalent:

$BEF = GHG_D + GHG_I$

<u>Direct Emissions:</u>

$GHG_D = E_f \times SFC$

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

SFC = Specific Fuel Consumption = 1,358 Btu/1000 lb steam

Direct emissions are then calculated as:

GHG_D = 117 lb-$CO_{2(e)}$/MMBtu x 1.358 MMBtu/1000 lb steam
= 158.9 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[4]:

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

T = gas temperature, °R. Assuming constant heat capacity, gas temperature is based on the mix temperature of fresh combustion air (at 68 F) plus 30 % FGR (at 503 F):

$$T = \frac{12{,}164 \text{ scf} \times 68^o + 12{,}586 \text{ scf} \times 30\% \times 503^o}{12{,}164 \text{ scf} + 12{,}586 \text{ scf} \times 30\%}$$

T = 171 °F or 631 °R

M = scf combustion air + flue gas x $\%_{FGR}$ (per 1000 lb steam)

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

M = (12,164 scf air/MMbtu + 12,586 scf flue gas/MMBtu x 30%) x 1.346 MMBtu/1000 lb steam = 21,455 scf 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 + 25.5 = 432.5 "WC

Substituting the given values into the equation:

Bhp-hr/1000 lb steam = 2.85

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

= (2.85 x 0.7457)/87% = 2.44 kWh/1000 lb steam

GHG_I = GHG (electric motors)
= 0.524 lb-$CO_{2(e)}$/kWh x 2.44 kWh/1000 lb steam
= 1.27 lb $CO_{2(e)}$ per 1000 lb steam production

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

BEF = *158.9 + 1.3 = 160.2 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:

Use of Economizers on Boilers

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 an achieved-in-practice approach for improving boiler thermal efficiency, 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. Economizers which reduce the flue gas temperature below 200^oF are considered to be “condensing” economizers since there is a potential for moisture to condense out of the flue gas at which point stainless steel construction is typically required for corrosion resistance. For flue gas temperatures above 200^oF (“standard” economizer), carbon steel construction is normally adequate. Economizer designs based on an approach of 20^oF or less (temperature differential between flue gas leaving the economizer section and the water entering the section) are achieved-in-practice for standard economizer designs while an approach of 50^oF is achieved in practice for condensing designs (see Appendix A).

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^oF return water), true condensing economizer operation becomes possible wherein the stack temperature may be lowered below the dew point of the flue gas (approximately 135^oF). 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 efficiencies above 90% are achievable.

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. A boiler equipped with a standard economizer system may only be capable of achieving 85-86% thermal efficiency when return water temperatures exceed 200^oF. 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 GHG reduction measure by specifying a required temperature approach of the economizer. A standard based on an approach temperature can be applied to all boilers even though they may exhibit a wide variation in return water temperature and, when established at a maximum values of a 20^{o}F approach for a standard economizer and 50^{o}F approach for a condensing economizer, the standard meets the definition of BPS for this class and category.

The District's analysis of this reduction 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^{o}F (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 a standard economizer which heats the 227^{o}F deaerated feedwater to the maximum extent possible based on a 20^{o}F economizer approach, will yield substantial improvement in boiler thermal efficiency (in the range of 5-6 percentage points for overall boiler efficiency depending upon the specifics of the application).

The specified economizer operation with a 20^{o}F approach may problematic in some boilers which exhibit higher temperature margins between flue gas temperature and steam saturation temperature or those employing a high pressure condensate recovery which may result in a relatively high temperature for the boiler feedwater, limiting the available heat sink for operation of an economizer. In these cases, meeting the 20^{o}F approach could result in either an 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^{o}F below drum saturation temperature to avoid mechanical problems) or, in the case of a unit which is already operating with relatively high temperature feedwater, installation of an economizer on a could result in a very limited improvement in energy efficiency. To address these issues, the District has added the following provisions to the BPS:

The economizer design criterion does not apply in any instance where the resulting feedwater temperature would exceed $T_s - 30$ where T_s is the saturation temperature of water at the steam drum operating pressure. In this case, the economizer criterion is a design water outlet temperature of $T_s - 30$.

When the feedwater supply temperature to the economizer would exceed $T_s - 50$, a stack temperature not exceeding $T_s + 100$ is required in lieu of the 20^{o}F approach criterion which represents the best achieved-in-practice criterion for boilers operating without an economizer. When the water temperature to the economizer is less than $T_s - 50$, the economizer operation is able to recover sufficient energy from the stack gas to heat the feedwater a minimum of 20^{o}F which will provide a gain in boiler efficiency of at least 1.5 to 2.0 percentage points.

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 may be used to further enhance the energy recovery. 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 150^{o}F or less, an minimum additional improvement of approximately 2 percentage points in boiler thermal efficiency can be achieved with a 2nd stage economizer. Establishing a 150^{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. This standard has been restricted to boilers rated 20 MMBtu per hour and larger since two stage systems are not typically installed on small boilers and may be cost prohibitive in small systems. In addition, units rated less than 20 MMBtu/hr represent less than 20 % of the total fired duty of boilers 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.

Air Pre-heaters

Another way to recover heat from the boiler flue gases is by use of an air preheater. In this case the recovered heat is transferred to the incoming combustion air and returned to the boiler, improving boiler 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 more rare 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 may be problematic due potential impacts on NO_x emissions from the unit. In general, where other low temperature heat receptors are available, 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 a general designation as BPS. However, the BPS would allow use of air preheaters in lieu of economizers where it is demonstrated that the proposed system achieves the same level of heat recovery from the stack gases.

Boiler Blowdown Heat Recovery

Since the temperature of boiler blowdown water is the same as that of the steam, energy losses associated with boiler blowdown may be significant. Typical boiler operation is a continuous blowdown of 4-8% of steam production but may be as high as 20% depending upon boiler parameters and the quality and proportion of makeup water. Achieved-in-practice technology for minimization of these losses includes:

1. Blowdown minimization:	a) Water pretreatment to reduce solids content and/or b) the use of automatic blowdown control systems
2. Flash steam recovery:	For boiler systems equipped with a deaerator, blowdown may be flashed into a separator vessel to allow recovery and use of the steam by the deaerator.
3. Feedwater heat exchanger	Blowdown may be routed through a heat exchanger for indirect heat transfer with the boiler makeup water. Although this system effectively recovers waste heat from the blowdown stream, it reduces potential

recovery of heat from the boiler stack since it increases the temperature of the water flowing to the stack economizer. Therefore, the net effect of this recovery technique may be minimal when considered in the context of the BPS.

Consideration of the reduction measures above reveals that only Items 1b and 2 can be considered feasible for inclusion as GHG reduction measures for this BPS. These measures provide significant improvement in boiler thermal efficiency (one percentage point or greater) when boiler blowdown exceeds 8% of total steam production.

Item 1a (water pre-treatment) presents a number of considerations and potential site-specific issues concerning its feasibility which are outside the scope of boiler design and efficiency, making it impractical for inclusion as a reduction measure for this BPS. Item 3 (feedwater heat exchanger) is a potential option for any facility in that it could be employed as an alternate measure to reduce the size of the stack economizer required by this BPS. Additionally, there may be site- specific heat uses which may allow recovery of energy from the blowdown. However, since the efficiency improvement provided by the heat exchange system would offset some of the efficiency gain of the economizer requirements of this BPS and since the consideration of other site specific heat recovery would be insufficiently general for designation as BPS, Item 3 will not be included as a feasible reduction measure.

Use of Oxygen Trim Systems

The combustion process in a boiler generally requires an excess of air (air in excess of the stoichiometric requirement for combustion of the fuel) to ensure efficient combustion and safe operation. Operations which exceed the minimum amount of excess air required for clean and safe operation result in a loss of efficiency as a result of the increased stack losses. When boiler burners are manually tuned on a periodic basis, they are typically adjusted to a conservatively high excess air value, ensuring safe operation over the entire operating range of the boiler.

Additionally, low efficiency burners or those employing high flue gas recirculation rates to control NO_x emissions may require operation with up to 4-5% excess oxygen to ensure stable operation. From an efficiency standpoint, the excess O_2 means that there are not only energy losses are incurred to heat the excess air up to the stack temperature but, 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 with flue gas recirculation rates below 10%, an O_2 trim system will allow reliable boiler operation at 3% O_2 providing significant energy savings when compared to a periodic manual adjustment of excess air. Note that such operation is generally only possible when the burner output is greater than 20% of rated output; operations at less than 20% generally occur during startup or during idling periods for the boiler.

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 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 an SCR relative to boiler size.

<u>Limiting Flue Gas Recirculation (FGR)</u>

FGR is utilized to control combustion temperature at the burner with recirculation rates up to 40-45% in some ultra low NOx applications. This recirculation has a negative impact on boiler performance since it typically requires operation at higher excess air rates 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.

<u>Use of Premium Efficiency Motors with Speed Control</u>

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 the combustion air fan operation by use of a variable speed electric motor will provide substantial energy savings when compared to operation 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 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.

Use of High Efficiency Combustion Air Fans

The peak efficiency of centrifugal fans may vary from 60 to 80% depending upon fan design and application. Use of a higher efficiency fan provides either savings in indirect GHG emissions due to the significant reduction in electric motor horsepower for motor-driven fans or savings in direct GHG emissions when the fan is driven by a steam turbine. However, the absolute value of efficiency which can be achieved is highly dependent upon the specific operating conditions including flow, pressure, and temperature, all of which may vary significantly for any specific boiler. Given this variability as well as the absence of any effective industry standard for fan efficiency, the District’s opinion is that specification of combustion air fan efficiency cannot be realistically included as a technologically feasible reduction measure in the BPS for boilers at this time.

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 2 **Technologically Feasible GHG Reduction Measures for *New Boilers with Operating Steam Pressure 75 psig and Greater, Fired Exclusively on Natural Gas or LPG***	
Reduction Measure	**Qualifications**
1. The boiler shall be either equipped with an economizer system meeting the following design criteria or shall be equipped with an approved alternate heat recovery system which will collectively provide heat recovery from the boiler flue gas which is equivalent.	
Economizer System Criteria A. Except for boilers subject to the requirements of items B or C below, the economizer system shall consist of, as a minimum, a single stage economizer section which will recover energy from the boiler flue gas by heat exchange with the boiler feed water. The economizer system shall be designed at maximum boiler firing rate to either 1) reduce the temperature of the economizer flue gas outlet to a value no greater than 20°F above the temperature of the boiler feed water at maximum firing rate, or 2) heat the boiler feed water to a temperature which is no less than 30°F below the steam temperature at the steam drum, or 3) reduce the final temperature of the boiler's flue gas to a temperature no greater than 200°F. *Note: For purposes of this BPS, feedwater temperature is defined as the temperature of the water stream delivered to the boiler from the deaerator or feedwater tank.*	*An economizer directly increases boiler efficiency (resulting in reduced GHG emissions) by adding heat transfer surface to the unit for recovery of energy from the flue gas. This measure is achieved in practice.*
B. For boilers with a feedwater temperature greater than or equal to T_s - 50, where T_s is the saturation temperature of steam at the steam separator pressure in °F, the steam generator shall be designed, in lieu of the requirements of item A above, to achieve a flue gas temperature no greater than the steam saturation temperature (°F at the steam drum operating pressure) plus 100°F.	*The feasibility of heat recovery from the stack gases is dependent upon having an adequate heat absorption capability in the feedwater (measured as the difference between the steam saturation temperature and the feedwater temperature). High feedwater temperatures are indicative of a facility which has implemented measures for recovery of high temperature condensate from the steam utilization operation. When feedwater temperature exceeds (T_s-50) °F, installation of an economizer is considered impractical. In the absence of an economizer, this provision requires boiler performance which is considered to be best achieved-in-practice for a boiler not so equipped.*

C. For boilers with rated capacity in excess of 20 MMBtu/hr which have a average water supply temperature which is equal to or less than 150°F, the boiler shall equipped with an economizer designed to reduce the temperature of the flue gas outlet to a value no greater than 50°F above the water supply temperature when the boiler is operating at maximum firing rate. *Note: For purposes of this BPS, water supply temperature is defined as the weighted average temperature of the combined makeup water and the recovered condensate delivered to the boiler upstream of any deaerator or other feedwater preheater but after benefit of any other heat recovery operations which recover waste heat from the boiler by transfer to the boiler water supply (such as boiler blowdown heat recovery).*	*Lower water supply temperatures provide additional opportunity to recover heat from the boiler flue gas, resulting in increased efficiency and reduced GHG emissions. Where applicable, a 2nd stage economizer provides additional heat transfer surface to the unit for recovery for this purpose. This measure is achieved in practice.*
2. Electric motors driving combustion air fans or induced draft fans shall have an efficiency meeting the standards of the National Electrical Manufacturer's Association (NEMA) for "premium efficiency" motors and shall be operated with a variable 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 is achieved in practice.*
3. *For boilers with rated fired duty in excess of 20 MMBtu/hr and an operating steam pressure of 125 psig or greater, the boiler shall be 1) equipped with an O_2 trim system and be designed to control oxygen content of the stack gases to a maximum of 3 volume % dry basis except during any period where the rate of fuel consumption by the boiler is less than 20% of maximum rated firing and 2) shall be designed to limit the recirculation of flue gas to a value not exceeding 10 percent of total flue gas volume while meeting the applicable requirements for control of NOx emissions from the boiler.*	*This measure obtains reductions in both direct and indirect GHG emissions. Direct GHG emission reductions are achieved by minimizing efficiency losses associated with high excess air operation. Indirect GHG emission reductions are achieved as a result of reductions in the power requirement for the combustion air fan. This measure is achieved in practice.*
4. For boilers with rated fired duty in excess of 20 MMBtu/hr and a boiler blowdown rate exceeding 8 % of steam production, the boiler shall be equipped with 1) an automatic boiler blowdown control system which will minimize boiler blowdown while controlling dissolved solids in the boiler water at an optimum level and 2) a flash steam recovery system which will recover flash steam from the blowdown pressure reduction and utilize it for feedwater heating in the deaerator or feedwater heater.	*This measure improves overall boiler efficiency (thus reducing direct GHG emissions) by minimizing energy losses associated with excessive boiler blowdown in larger boilers.*

All of the control measures identified above are consistent 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 project design specifications for existing boiler installations operating in the San Joaquin Valley and elsewhere. See Appendix A for details. The review indicated the following with respect this class and category:

- Standard economizer installations designed for a 20^{o}F approach to boiler feedwater temperature are achieved-in-practice. The District has identified several boiler operations in the San Joaquin Valley (SJV) currently operating with an economizer designed to this criterion.
- Condensing economizers with a 50^{o}F approach to the feedwater temperature are achieved in practice. Several condensing economizer operations have been identified in the SJV including one operation with a 50^{o}F approach to the feedwater temperature.
- A number of boiler operations in the SJV have been identified which have this feature.
- For boilers above 125 psig and above 20 MMBtu/hr, low excess air operation with zero FGR is achieved in practice. The District has identified several boiler operations in the San Joaquin Valley (SJV) currently operating with FGR < 10% and low excess air.

- Use of automatic blowdown controls and recovery of flash steam from continuous boiler blowdown are determined to be achieved-in-practice since these are recognized, well-established practices at boiler plants.

All technologically feasible GHG reduction measures listed in Table above meet the following criteria:

<u>All technology listed is in current commercial use.</u>

All technologically feasible GHG reduction measures listed in Table above are based on technology (condensing economizers, high efficiency motors with variable speed drives, O2 trim control and use SCR in lieu of high FGR) which is currently in commercial use. This technology has been in place for a significant number of years and was developed and implemented without benefit of grants, incentives or other financial subsidies.

<u>Implementation of all listed technology does not result in an increase in criteria pollutant emissions.</u>

In general, since all proposed measures do not affect the criteria pollutant emission factors and generally result in a reduction in the firing of fuel, criteria pollutant emissions will generally be reduced with implementation of BPS. The implementation of BPS may result in a requirement to utilize SCR technology for control of NOx emissions which would result in ammonia emissions due to ammonia slip through the SCR converter. Although ammonia is a non-criteria pollutant, it is recognized a precursor for PM2.5. However, ammonia is not a limiting reactant in the San Joaquin Valley and therefore any new ammonia emissions will not result in additional PM2.5 formation,

Therefore, all items are deemed to be Achieved-in-Practice. Since all of the achieved-in-practice measures identified are independent of each other, concurrent implementation of all measures results in a strictly additive benefit (none of the measures are mutually exclusive). Therefore, all identified reduction measures are considered to be a single measure in effect. Since there are no other mutually exclusive measures identified, there is in effect a single achieved in practice reduction measure identified. and the District proposes to deem the concurrent implementation of all identified achieved-in-practice reduction 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 Reduction 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 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 assumed 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.

- Stack O2 Concentration is 3% and FGR is limited to 10% since the basis is a unit greater than 20 MMBtu/hr
- Due to a BPS requirement to install an automatic blowdown system, it is assumed that continuous boiler blowdown will be reduced by 20%, or a blowdown rate of 6.4% of steam rate will be applicable.
- 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 50^{o}F above the average combined water temperature. Therefore, the stack temperature would be 180^{o}F at the maximum firing rate.
- Based upon a boiler heat and mass balance for the given conditions, the following quantities are applicable:
  - Net steam production is 787 lb/MMBtu fired or a Specific Fuel Consumption (SFC) of 1,000,000/782 = 1,271 Btu/lb steam
  - Flue gas rate is 11,768 scf/MMbtu fired
  - Combustion air rate is 10,767 scf/MMBtu fired
  - Boiler efficiency = 87%

- It is assumed that the unit will require a selective catalytic reduction system (SCR) for control on NOx emissions due to the limitation on FGR. Given a maximum of 10% FGR, burner is expected to produce 30 ppmv NOx. The District's current regulations will require this unit to achieve a NOx emission rate of 5 ppmv, requiring the SCR to reduce 25 ppmv of NOx in the flue gas. Greenhouse gas emissions associated with the production and transport of ammonia are included in the analysis. Indirect GHG emissions associated with manufacture and transport of ammonia for the SCR operation are determined to 0.038 lb CO2(e)/MMBtu fired (see Appendix 2).
- Flue gas side pressure drop for the boiler is adjusted from the baseline case to account for reduced flow through the boiler as a result of limits on FGR rate. For the BPS case with 10% FGR, flue gas rate through the boiler is 11,768 x 1.1 = 12,946 scf/MMBtu fired. For the baseline case, a boiler pressure drop of 13.5 "WC was determined based on a flow rate of 16,362 scf/MMBtu. Correcting this to the lower flow rate yields the following boiler pressure drop:

  13.5 "WC x $(12{,}946/16{,}362)^2$ = 8.5 "WC

- Since the BPS unit is assumed to be equipped with an SCR and includes additional economizer surface, the following additional pressure drops will be included:

SCR pressure Drop	2 "WC
Additional Economizer Pressure Drop	1 'WC

- Total system flue gas pressure drop is calculated as follows:

Burner	12.0 "WC
Boiler	8.5 "WC
Economizer	1.0
SCR	2.0
Total	23.5 "WC

- A 30% reduction in net specific electric power consumption is attributed to use of VFD during turndown periods.
- All other assumptions and basis are the same as the baseline case.

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

SFC = Specific Fuel Consumption = 1,271 Btu/1000 lb steam (as stated in basis)

Direct emissions are then calculated as:

GHG_D = 117 lb-$CO_{2(e)}$/MMBtu x 1.271 MMBtu/1000 lb steam
= 148.7 lb/1000 lb steam

Indirect Emissions

Indirect emissions consist of emissions from operation of electric motors and from the production and shipping of ammonia for operation of the SCR system.

Electric Motor Operations:

Indirect emissions produced from operation of the electric motor on the combustion air fan 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]:

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

T = gas temperature, ^oR. Assuming constant heat capacity, gas temperature is based on the mix temperature of fresh combustion air (at 68 F) plus 30 % FGR (at 503 F):

$$T = \frac{10{,}767 \text{ scf} \times 68^o + 11{,}768 \text{ scf} \times 10\% \times 503^o}{10{,}767 \text{ scf} + 11{,}768 \text{ scf} \times 10\%}$$

T = 111 ^oF or 571 ^oR

M = scf combustion air + flue gas x $\%_{FGR}$ (per 1000 lb steam)

M = (10,767 scf air/MMbtu + 11,768 scf flue gas/MMBtu x 10%) x 1.263 MMBtu/1000 lb steam = 15,085 scf gas/1000 lb steam

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

n = 0.2857 (typical for diatomic gases)
E = efficiency = 60%
p_1 = atmospheric pressure = 407 "WC
p_2 = atmospheric pressure + pressure drop
= 407.0 + 23.5 = 430.5 "WC

Substituting the given values into the equation:

Bhp-hr/1000 lb steam = 1.67

Applying a 30% reduction to account for the use of a VFD:

Combustion air fan specific energy consumption = (1-30%) x 1.67

= 1.17 Bhp-hr/1000 lb steam

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

= (1.17 x 0.7457)/95% = 0.92 kWh/1000 lb steam

GHG (electric motors) = 0.524 lb- $CO_{2(e)}$/kWh x 0.92 kWh/1000 lb steam
= 0.48 lb $CO_{2(e)}$ per 1000 lb steam production

Indirect GHG Emissions Due to Ammonia Manufacture:

GHG (ammonia) = SFC x E_a
= 1.246 Btu fuel/1000 lb steam x 0.038 lb CO2(e)/ MMBtu
= 0.05 lb CO2(e)/1000 lb steam

Total Indirect Emissions:

GHG_i = GHG (electric motors) + GHG (ammonia)
= 0.48 + 0.05 = 0.53

GHG Emissions per Unit of Activity is then calculated as:

G_a = GHG_D + GHG_I = *148.7 + 0.5 = 149.2 lb-* $CO_{2(e)}$*/1000 lb-steam*

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

G_p = (BEF - G_a) / BEF = (160.2 – 149.2)/160.2 = 6.9%

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:

<u>Best Performance Standard for New Boilers with Operating Steam Pressure 75 psig and Greater, Fired Exclusively on Natural Gas or LPG</u>

Boilers meeting this Best Performance Standard must comply with all four elements of this BPS (items 1, 2, 3 and 4 listed below) where applicable:

1. The boiler shall be either equipped with an economizer system meeting the following design criteria or shall be equipped with an approved alternate heat recovery system which will collectively provide heat recovery from the boiler flue gas which is equivalent.

<u>Economizer System Criteria</u>

A. Except for boilers subject to the requirements of items B or C below, the economizer system shall consist of, as a minimum, a single stage economizer section which will recover energy from the boiler flue gas by heat exchange with the boiler feed water. The economizer system shall be designed at maximum boiler firing rate to either 1) reduce the temperature of the economizer flue gas outlet to a value no greater than 20°F above the temperature of the boiler feed water at maximum firing rate, or 2) heat the boiler feed water to a temperature which is no less than 30°F below the steam temperature at the steam drum, or 3) reduce the final temperature of the boiler's flue gas to a temperature no greater than 200°F.

Note: For purposes of this BPS, feedwater temperature is defined as the temperature of the water stream delivered to the boiler from the deaerator or feedwater tank. For steam systems employing a high pressure condensate return, the feedwater temperature is the weighted average of the temperatures of the returned high pressure condensate and of the water from the deaerator or feedwater tank.

B. For boilers with a feedwater temperature greater than or equal to T_s - 50, where T_s is the saturation temperature of steam at the steam separator pressure in ^oF, the steam generator shall be designed, in lieu of the requirements of item A above, to achieve a flue gas temperature no greater than the steam saturation temperature (^oF at the steam drum operating pressure) plus 100^oF.

C. For boilers with rated capacity in excess of 20 MMBtu/hr which have a average water supply temperature which is equal to or less than 150^oF, the boiler shall equipped with an economizer designed to reduce the temperature of the flue gas outlet to a value no greater than 50^oF above the water supply temperature when the boiler is operating at maximum firing rate.

Note: For purposes of this BPS, water supply temperature is defined as the weighted average temperature of the combined makeup water and the recovered condensate delivered to the boiler upstream of any deaerator or other feedwater preheater but after benefit of any other heat recovery operations which recover waste heat from the boiler by transfer to the boiler water supply (such as boiler blowdown heat recovery).

2. Electric motors driving combustion air fans or induced draft fans 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 speed control or equivalent for control of flow through the fan.

3. For boilers with rated fired duty in excess of 20 MMBtu/hr and an operating steam pressure of 125 psig or greater, the boiler shall be 1) equipped with an O_2 trim system and be designed to control oxygen content of the stack gases to a maximum of 3 volume % dry basis except during any period where the rate of fuel consumption by the boiler is less than 20% of maximum rated firing and 2) shall be designed to limit the recirculation of flue gas to a value not exceeding 10 percent of total flue gas volume while meeting the applicable requirements for control of NOx emissions from the boiler.

4. **For boilers with rated fired duty in excess of 20 MMBtu/hr and a boiler blowdown rate exceeding 8 % of steam production, the boiler shall be equipped with 1) an automatic boiler blowdown control system which will minimize boiler blowdown while controlling dissolved solids in the boiler water at an optimum level and 2) a flash steam recovery system which will recover flash steam from the blowdown pressure reduction and utilize it for feedwater heating in the deaerator or feedwater heater.**

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 Step 4 and ranked in Step 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 Step 6:

No other Achieved-in-Practice options were identified.

V. Appendices

Appendix A:	Achieved-in-Practice Analysis
Appendix B:	GHG Emission Factor for Ammonia Production and Transport
Appendix C:	Public Notice of Intent
Appendix D:	Comments Received During the Public Notice of Intent and Responses to Comments
Appendix E:	Comments Received During the Public Participation Process (1st BPS Draft) and Responses to Comments
Appendix F:	Comments Received During the Public Participation Process (2nd BPS Draft) and Responses to Comments

Appendix A
Achieved-in-Practice Analysis

Achieved-in-Practice Summary for Proposed GHG Reduction Measures

Table A-1 lists boiler design information for six California facilities, five of which are located in the San Joaquin Valley and currently have District permits. Each facility listed demonstrates the achieved-in-practice status of one or more of the reduction measures proposed by this BPS.

GHG Reduction Measure 1A: (standard 1st stage economizer with 20 °F approach)

Facilities 1, 3 and 4 are equipped with a single economizer operating on boiler feedwater designed to this standard. Facility 3 has been operating for two years with this feature and.has reported that no issues have arisen with the economizer.

GHG Reduction Measure 1B: (2nd Stage economizer with 50 °F approach for units over 20 MMBtu/hr):

Facilities 2, 5 and 6 are currently operating 2-stage economizer systems operating on boiler feedwater. All facilities report good operation. Facility 2 demonstrates a facility with a 50 °F design approach on the 2nd stage economizer. All facilities have reported that no problems have been encountered with the units.

GHG Reduction Measure 2: (high efficiency electric motors and variable speed drives)

The majority of the facilities surveyed have incorporated these features. Discussion with boiler manufacturer representatives has indicated that these features are routinely recommended for all new boiler installations.

GHG Reduction Measure 3: (limited FGR and excess air for boilers exceeding 20 MMBtu/hr)

As indicated in Table A-1, a number of facilities are successfully operating in this mode with most reporting that they use no FGR at all. Most facilities reported general improvement in boiler operation (stability and turndown) when operating with reduced FGR rates.

GHG Reduction Measure 4: (recovery of flash steam and use of automatic boiler blowdown control)

The facilities listed in Table A-1 were not surveyed with respect to this criterion. However, flash steam recovery from continuous blowdown, as well as use of automatic blowdown control, are generally recognized as achieved in practice operations.[6][7]

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[6] Boiler Blowdown (Best Operating Practices for Boiler Blowdown), NCDENR Fact Sheet, N.C. Division of Pollution Prevention and Environmental Assistance

[7] Energy Tips – Steam, Steam Tip Sheet #9, U.S. Department of Energy, Energy Efficiency and Renewable Energy, January 2006.

Table A-1
Facilities Demonstrating Achieved-in-Practice Elements of the Best Performance Standard for Boilers > 75 psig

Facility	District Permit	Location	Pressure psig	Fired Duty MMBtu/hr	1st Stage Approach oF	2nd Stage Approach oF	Stack Temperature oF	Operation Since	Achieved-In-Practice Elements
Los Gatos Tomatos	C-787-7-3	Huron	350	182	20	N/A		2009	1st stage economizer with 20 degree approach, variable speed drives, FGR< 10%, O2 trim system
Del Monte Foods	N-1626-8-1	Modesto	275	59	50	50	110	2007	Two-stage condensing economizer with 50 degree approach on 2nd stage, variable speed drives, FGR< 10%, O2 trim system
Del Monte Foods	C-366-1-8 & '2-9	Hanford		182 each	20	N/A		2008	1st stage economizer with 20 degree approach, variable speed drives, FGR< 10%, O2 trim system
J.G Boswell	C-7336-8-0	Corcoran	350	148.14	19	N/A	259	June, 2010	1st stage economizer with 20 degree approach, variable speed drives, FGR< 10%, O2 trim system
Styrotek	S-1075-3-9	Delano	100	16.3	105 (est)	108	178	March, 2010	Two-stage condensing economizer
Mars PetCare	N/A (SCAQMD)	Victorville	110	23.5	69 (est)	125	180	March, 2010	Two-stage condensing economizer

Appendix B
GHG Emission Factor for Ammonia Production and Transportation

Indirect GHG Emissions Associated with Production and Delivery of Ammonia

An emission factor for GHG emissions associated with the production and delivery of ammonia to a facility for use as a reagent for selective catalytic reduction (SCR) of NOx is developed in the following analysis:

Basis:

- 20 MMBtu/hour natural gas-fired boiler operating at 87% efficiency with 5 ppmv NOx with 3% O2.
- Based on operating with less than 10% FGR, NOx emissions at the burner (upstream of SCR unit) are assumed to be 30 ppmv.
- F-Factor for Natural Gas: 8,578 dscf/MMBtu corrected to 60°F (40 CFR 60, Appendix B)
- Flue gas from the unit totals 176,866 scfh based on the given boiler rating and F-Factor with an O2 concentration of 3%.
- Ammonia slip from the SCR unit is 10 ppmv.
- Per the International Fertilizer Industry Association (IFA)[8], natural gas is used for the vast majority of all worldwide ammonia production with the exception of China which uses coal. The GHG emission factor for production of ammonia from natural gas is 1.6 tons CO2 per ton of ammonia.
- Per the SCR reaction, one mol of ammonia is consumed for each mole of NO reduced. The combining weight is therefore the ratio of NH3 molecular weight (17) to the molecular weight of NO (30) or 17/30 = 0.57 lb-NH3/lb-NOx
- Bulk shipping of ammonia is based on a shipping distance of 2000 miles (to California from a gulf coast location) in a 24,000 lb quantity in a heavy diesel truck with fuel consumption of 6 miles per gallon. It is then shipped 100 miles round trip in a 300 lb quantity for local delivery in a light duty diesel truck operating at 10 miles per gallon.
- Diesel emissions are 22.4 lb CO2 per gallon of diesel. (CCAR document)

Calculate ammonia consumed in the SCR reaction:

Lb-moles NOx produced at the burner

30 ppmv x 176,866 scfh x 1 lb-mol/379.5 scf = 0.014 lb-mol/hour

[8] Energy Efficiency and CO2 Emissions in Ammonia Production, International Fertilizer Industry Association (IFA), December 2009.

Lb-moles NOx emitted at stack

5 ppmv x 176,866 scfh x 1 lb-mol/379.5 scf = 0.0023 lb-mol/hour

Lb-moles NOx reduced by SCR = 0.014 – 0.0023 = 0.0117 lb-mol/hour

Lb-moles NH3 consumed by SCR reaction = 0.0117 lb-mol/hour

Calculate ammonia losses due to slippage

10 ppmv x 176,866 scfh x 1 lb-mol/379.5 scf = 0.0047 lb-mol/hour

Total lb-mols ammonia use = consumption + slippage = 0.0117 + 0.0047=

= 0.0164 lb-mol/hour

Total lb ammonia use = 0.0164 lb/mols x 17 lb/mol = 0.28 lb ammonia

Calculate GHG emissions associated with manufacture of ammonia:

1.6 lb CO2/lb ammonia x 0.28 lb-ammonia = 0.45 lb CO2

Calculate transportation emissions:

Bulk shipping

2000 miles x 1 gal/6 miles x 22.4 lb CO2/gal / 24000 lb ammonia = 0.31 lb CO2/lb ammonia

Local Delivery

100 miles x 1 gal/10 miles x 22.4 lb CO2/gal / 300 lb ammonia = 0.75 lb-CO2/lb-ammonia

Total Transportation emission factor = Bulk Shipping + Local Delivery
=0.31 + 0.75 = 1.06 lb CO2/lb ammonia

Total Transportation emissions = 1.06 lb CO2/lb ammonia x 0.28 lb ammonia = 0.30 lb CO2

Calculate overall GHG emission and the GHG emission factor

Total GHG Emissions = manufacture + transportation = 0.45 + 0.30 = 0.75 lb CO2

Overall GHG Emission Factor : 0.75lb-CO2/20MMBtu = 0.038 lb CO2/MMBtu

Appendix C
Public Notice of Intent

San Joaquin Valley
AIR POLLUTION CONTROL DISTRICT

HEALTHY AIR LIVING

Notice Of Development Of

Best Performance Standards

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Air Pollution Control District solicits public comment on development of Best Performance Standards for the following Stationary Source class and category of greenhouse gas emissions:

BOILERS
Subject to District Permitting Requirements

The District is soliciting public input on the following topics for the subject Class and Category of greenhouse gas emission source:

- Recommendations regarding the scope of the proposed Class and Category (Stationary GHG sources group based on fundamental type of equipment or industrial classification of the source operation),
- Recommendations regarding processes or operational activities the District should consider when establishing Baseline Emissions for the subject Class and Category,
- Recommendations regarding processes or operational activities the District should consider when converting Baseline Emissions into emissions per unit of activity, and
- Recommendations regarding technologies to be evaluated by the District, when establishing Best Performance Standards for the subject Class and Category.

Information regarding development of Best Performance Standard for the subject Class and Category of greenhouse gas emission source can be obtained from the District's website at http://www.valleyair.org/Programs/CCAP/CCAP_idx.htm.

Written comments regarding the subject Best Performance Standard should be addressed to Dennis Roberts by email, dennis.roberts@valleyair.org, or by mail at SJVUAPCD, 1990 East Gettysburg Avenue, Fresno, CA 93726 and must be received by **February 23, 2010**. For additional information, please contact Dennis Roberts by e-mail or by phone at (559) 230-5919.

Information regarding the District's Climate Action Plan and how to address GHG emissions impacts under CEQA, can be obtained from the District's website at http://www.valleyair.org/Programs/CCAP/CCAP_idx.htm.

Appendix D

Comments Received During the Public Notice of Intent and Responses to Comments

Stakeholders Written Comments:

Nationwide Boiler Incorporated (NBI)
Plains All America, L.P. (PAA)
Kern Oil and Refining Co. (KOR)
Enviro Tech Consultants, Inc. (ETC)
Berry Petroleum Company (BPC)
R.F. McDonald Co. (RFM)

1. **Comment:** In going forward with development of BPS for process heaters it is important to recognize that in certain facilities plant off gas is accountable for a large quantity of the fuel. The Plains LPG frac and isom facility in Shafter is currently under the refinery regulated portion of rule 4306 and 4320 for the heaters on site. It may be important to distinguish between PUC gas and plant off gas in future BPS requirements (PAA)

Response: The District recognizes that fuels other than natural gas or LPG may have specific limitations with respect to energy efficiency technology. The BPS will be clarified to reflect that it is applicable to these fuels only.

2. **Comment:** I would advocate that the strict prohibitory rules recently placed on this division of heaters through 4320, 4623 and 4455 would already have satisfactory BPS in place. (PAA, ETC)

Response: The District's prohibitory rules do not address GHG emission or energy efficiency and thus would not represent BPS.

3. **Comment:** In my opinion the District can not receive adequate information to form BPS without first meeting with industry and their representatives to discuss what the baseline period equipment is. A blanket request for information will only create confusion and the submittal of information that can only be applied to a single company. Once the District understands the difference not only between industrial types, but the differences within the same industry, can the District begin receiving adequate information to form an achievable and economical BPS. (BPC)

Response: The District recognizes the importance of industry responses to specific proposals. The draft BPS will be posted for public comments to ensure this input is received.

4. **Comment:** There are multiple types of equipment, facility design, and operational characteristics that make establishment of "BPS" difficult. We recommend that the District structure BPS following the existing categories and organization of the District's BACT guidelines. (ETC)

Response: Since BACT addresses only criteria pollutants and is determined under criteria different from that of BPS, the District cannot necessarily utilize the classifications established for BACT. To the extent that the BACT classification forms a reasonable classification for GHG emissions, it will be considered.

5. **Comment:** BPS needs to provide exemptions for small sources of GHG emissions. EPA is proposing a threshold of 25,000 MT CO2e, and a similar threshold should be part of any BPS determination. (ETC)

Response: Comment noted. Since this comment is general and not specific to the BPS for boilers, the District will not respond to this comment as a part of this document.

6. **Comment:** Cost effectiveness needs to be considered when determining BPS. (ETC)

Response: Cost effectiveness is included to the extent that is required under the definition of achieved-in-practice.

Appendix E

Comments Received During the Public Participation Process (1st Draft) and Responses to Comments

Comments Received During the Public Participation Process and District Responses to Comments

Stakeholders Written Comments:

WZI INC. (WZI)
California Wastewater Climate Change Group (CWCCG)
Nationwide Boiler Incorporated (NBI)
Southern California Gas Company (SCGC)
Southern California Boiler (SCB)
URS Corporation (URS)
Plains All American Pipeline, L.P. (PAAP)
Kern Oil and Refining Co. (KOR)
Enviro Tech Consultants, Inc. (ETC)
Berry Petroleum Company (BPC)
R.F. McDonald Co. (RFM)

1. **Comment:** The District's analysis should account for the cyclic multi-unit operation of real world-integrated facility operation as opposed to the simplistic maximum design case for a "single stand-alone" boiler cycle. (WZI)

Response: The District's technical approach for development of the BPS is purposely based on limiting the consideration to the achievable emission reductions for a single stand alone unit to ensure that it is technically feasible in all cases (site specific considerations are not a factor). Since the BPS is strictly based on achieving a level of heat recovery consistent with the heat absorption capability of the return water to the boiler, the unit can be considered on a stand alone basis without regard to multi-unit operation or other system integrations. The District recognizes that additional energy recovery opportunities are often available when the unit is integrated with other low temperature heat users which may be present at any particular facility. However, these would be highly site specific and thus they could not be considered within the context of establishing a basic level of performance for BPS. If such opportunities exist at a given facility, the BPS allows their use in the recovery of heat from the boiler stack to meet the BPS specification as long as an equivalent level of heat recovery from the stack gases is obtained.

2. **Comment:** The District's analysis should account for the incorporation of pinch point analysis at the operating conditions to determine if the low temperature/low energy value heat that is recovered at temperatures approaching the bottom of a realistic facility-wide carnot cycle is even usable in a normally fully integrated process where other low value heat sources and pinched sinks already exist and must be displaced or replaced. The maximum design case largely ignores valley summer high temperatures which approach the heat sink temperature necessary for a 95% boiler to work in an operational facility. (WZI)

Response: The District's initial BPS did not fundamentally specify a 95% thermal efficiency. As stated in the initial BPS, the fundamental requirement was to recover sufficient heat from the boiler exhaust such that the exhaust temperature is no more than 20 ^{o}F greater than the boiler water return temperature. This essentially provides consideration of pinch points with respect to determination of BPS. Since consideration of heat sinks was limited to the boiler return water, no consideration of heat sources or sinks within the facility was required. However, the BPS does allow each facility to utilize low temperature heat sinks to meet the equivalent efficiency of the BPS. A thermal efficiency of 95%, as specified in the initial BPS, was given as the maximum efficiency which could be required regardless of the return water temperature. However, the District recognizes that a 95% efficiency specification is excessively stringent with respect to a reasonable determination of "achieved-in-practice" and that, in general, the specification of a fixed value of efficiency presents certain issues with respect to definitions and methods of determination. As a result, the District has removed the specification of 95% efficiency as a limiting case.

3. **Comment:** The District's analysis should account for the use of low temperature exhaust which may force conditions in the exhaust gas path at varying load conditions to meet localized dew points (and low pH conditions) at tube walls that will lead to premature corrosion failures. (WZI)

Response: Economizers (and stack sections) which will operate under condensing conditions are commonly constructed of corrosion resistant materials. Use of stainless steels in such applications is common and has been proven to provide acceptable service.

4. **Comment:** District's analysis should account for [a possibility that] the need to maximize boiler design performance may create a need to forego burner designs that are more attuned to Valley-wide criteria pollutant objectives to meet the maximum design GHG criteria while meeting the necessary range of facility operation; (WZI)

Response: The District recognizes that reductions in GHG emissions consistent with the achieved in practice element of the BPS may limit the selection of technology for control of criteria pollutants. Where there are multiple achieved-in-practice control technologies available for criteria pollutants and certain of the technologies are fundamentally more energy intensive than others, a BPS specification which favors the use of the less energy intensive technologies would be consistent with the District's policies and definitions for development of BPS. In the District's opinion, the BPS specification, as currently stated, would not result in any increase in criteria pollutant emissions nor limit the range of operation for a properly designed unit.

5. **Comment:** We are concerned that the case-by-case resolution of these issues (comments 1 through 4) including the internal BACT/BPS conflict will delay much needed improvement projects.

Response: The BPS is fundamentally a test of "significance" with respect to GHG emissions which will serve to streamline the application process where an Authority to Construct application has proposed BPS. Such an application would directly be deemed "not significant" with respect to GHG emissions and would then move normally through the District's permitting process. A fundamental objective of the BPS is to establish a single specification which, if met, would automatically exclude a "case-by-case" analysis. Boilers not proposed with BPS would require a specific analysis and would have other avenues available to satisfy the CEQA requirements for the project. BY definition, BPS will not conflict with the District's BACT determination for this class and category.

6. **Comment:** Proper facility integration can lead to overall cycle efficiencies (reducing GHG) while meeting the operational needs of the affected businesses. In addition, I respectfully suggest that the District staff consider the wisdom of extending any claims concerning boiler performance at a single design point with a clear understanding about facility operations, contract obligations and normal operational nodes. Any claimed performance that is not backed by a vendor's commitment to consequential damages for failure to perform as promised will likely result in poor after-the-fact performance. This will lead to numerous breakdowns or reductions in efficiencies throughout the remainder of the facility operations leaving the industry boiler owner with the duty to fix new problems created by poorly matched boiler
designs in a time when valuable capital is in short supply. (WZI)

Response: The District concurs that proper facility integration can lead to GHG emission reductions. To the extent that a facility implements energy conservation techniques which increase the energy level of the boiler return water, the BPS specification automatically adjusts by only requiring a temperature approach to the return water temperature and when the return water is above 150 ^{o}F, the requirement for a 2nd stage economizer is completely dropped. By allowing other alternatives which are equivalent in stack heat recovery to the proposed economizer operation with boiler return water, the BPS recognizes that there are often site specific opportunities for facility integration based on transferring low level thermal energy from the boiler flue gas to other heat users in the facility.

The BPS specification is essentially directed at requiring boilers to be equipped with economizers to improve efficiency. The use of multi-stage economizers with condensing operation is a relatively mature, achieved-in-practice technology which provides significant improvements in thermal efficiency when considering only the preheating of boiler feed water. The District's review of currently operating facilities indicates that economizer designs produced and guaranteed by any one of a number of reputable manufacturers will include considerations for handling off-normal considerations and will provide reliable service. Since the BPS is only applicable to new units, issues concerning poorly matched boiler/economizer designs should be minimal.

7. **Comment:** The use of GHG emission allowances/credits should not be imposed until the District itself is able to define a reasonable source of the credits or develop a mechanism to provide reasonable access to the required allowances/offsets. The District may want to establish a funding mechanism through agreements. This imposition of "buying an out for the difference" could then meet a District imposed requirement without subjecting operations to unnecessary curtailment due to unmet needs for system improvements and repairs while: **I)** trying to source prototype allowances and offsets, *2)* satisfy the District veracity requirements and 3) meet the non-GHG related BACT requirements in a time period that does not result in permitting delays to a point that the project requirements and/or regulations change and the process of permitting starts over. (WZI)

Response: Comment noted. Since this comment is of a general nature and not specifically directed at the proposed BPS for boilers, the District will not respond to this comment as a part of this document.

8. **Comment:** Projects receiving energy-efficiency incentive program funding from a California utility inherently meet the best performance standards for mitigation of green house gases. Such projects have to demonstrate fuel savings, even if there are production increases, and are achieved-in-practice. (SCGC)

Response: While utility incentive programs establish energy efficiency criteria which promote GHG reductions, the criteria do not necessarily match the definition of Best Performance Standard. Per the District staff report, BPS is "the <u>most</u> 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". The District's BPS for this class and category must meet this definition.

9. **Comment:** There are many phrases regarding the BPS in the staff report that are ambiguous. It is difficult to differentiate the meaning of and differences between the phrases. At various points in the staff report, the following phrases are used to describe an element of the BPS: "achieved-in-practice", "state-of-the-art", "current state of the art", "achieved state-of-the-art", "technologically feasible", "economically feasible", "best practical performance", "common use", "common and economical", "commonly available", "commercially available", and "most effective". In addition, the definition of "Achieved-in-Practice" is not presented until page 18 after most of the BPS analysis and use of the other phrases above. SoCalGas requests that the District use consistent terminology and provide definitions for such terminology at the beginning of the document. Definitions

should be consistent with those used in the New Source Review program and District Rules (and documented as such), or labeled as a specific definition just for the BPS. (SCGC)

Response: The District has revised the BPS document to eliminate use of redundant terms and to provide definitions as required.

10. **Comment:** While the staff report provides some references for emission factors and engineering calculations, there are no references or documentation provided for most *of* the District analysis. It is important to know the specific source of the information when analysis from such information is used to make regulatory decisions. Lack of documentation for the statement on page 12, that, "boiler thermal efficiency can exceed *95%* for boilers designed with current state of the art economizers," is particularly concerning in light of the comments below on BSP element 1 - 95% thermal efficiency. It is not enough that the District provides vendor brochures as documentation. As sales literature, the brochures use very optimistic performance data and best-case project profiles that are not necessarily typical installations. SoCalGas requests that names and dates of personal communications (telephone, email, etc.), and titles of written literature used in decision-making be provided in a reference section of the staff report. (SCGC)

Response: See response to comment #2 with respect to the thermal efficiency requirement. Selection of a 20 ^{o}F approach as a design basis for heat recovery is based on operations in the San Joaquin Valley and elsewhere which operate economizers meeting this design criteria. An appendix has been added to the report to list these facilities.

11. **Comment:** Best Performance Standards are essentially CEQA mitigation measures. The discussion of "Achieved-in-Practice", on page 24 of the staff report quotes the definition of Best Performance Standard from the Final Staff *Report – Climate Change Action Plan: Addressing GHG Emissions Impacts under CEQA* (pages 60 - 61). This definition states that the BPS, as a means of reducing or limiting greenhouse gases, is "economically feasible". This is consistent with CEQA mitigation measures being subject to a feasibility analysis, which has a financial component, pursuant to Public Resources Code 521002. However, the staff report is deficient because it does not contain an economic feasibility analysis. The District needs to include a complete feasibility analysis including a financial element in the staff report, since the District in its CEQA lead agency role is developing this BPS for greenhouse gas mitigation. SoCalGas requests that the District include a cost-effectiveness evaluation step in BPS determination process. The District's well-established New Source Review Program-Best Available Control Technology determinations, that impose the lowest achievable emission rate, take into account cost effectiveness. Thus, it is reasonable to include this critical evaluation in the BPS determination. (SCGC)

Response: Please note that the BPS in itself does not mitigate any specific emissions and is primarily a standard by which a determination of the significance of GHG emissions is made. Per the definitions of BPS and "achieved-in-practice" as defined in the District's staff report, the only economic consideration involved with determination of whether a specific technology can qualify as BPS is to "consider the extent to which grants, incentives or other financial subsidies influence the economic feasibility of its use". All technology proposed as a basis for establishing BPS (condensing economizer, high efficiency motor with variable speed drive, SCR in lieu of high rate FGR) has been in use for a significant number of years and has been developed and commercialized without benefit of grants or incentives.

12. **Comment:** The District only uses the Pacific Gas & Electric's electric power generation factor in the staff report. With no comparison, it is difficult to evaluate whether this is an appropriate factor for facilities in the south valley with electric service provided by Southern California Edison. Please provide this factor from Southern California Edison as well. (SCGC)

Response: The District has used the power generation for PG&E based on this being applicable to the majority of facilities in the San Joaquin Valley and thus representative of the average. The factor is only used to assess the expected average impact of BPS relative to the baseline as a percentage and there is no "regional" applicability of BPS. Thus any evaluations based on the SCE factor would have no relevance to the determination. The District will base its evaluation solely on the PG&E factor.

13. **Comment**: SoCalGas respectfully requests that the District not use the term "control measure" when referring to the BPS, In the context of the State Implementation Plan (SIP) and the District's rules, control measures are known to be required measures. It is important to make the distinction that the BPS is a CEQA option and not a required control measure for the SIP or District's rules. A better term might be reduction measure. (SCGC)

Response: The District concurs and has revised the term "control measure" to now be stated as a "reduction measure".

14. **Comment**: The District needs to provide analysis for all boilers in the stated category that may choose BPS for CEQA purposes. The BPS sets the category as "Gaseous Fuel-Fired Boilers with Rated Steam Pressure 75 psig and Greater" (psig means pound-force per square inch gauge), yet almost all of the analysis addresses 125-psig boilers. The only criteria examined for a 75-psig boiler (page 5) is that it could meet option 1) of BPS element number I. There is no analysis shown that a 75-psig boiler can meet any of the other BPS elements in numbers 1 through 4. (SCGC)

Response: As stated in the BPS evaluation, the emission reduction analysis presented is based on a boiler operating at 125 psig because this represents the most common pressure rating for industrial boilers above 75 psig. The analysis, as presented, evaluates the expected combustion efficiency and GHG emissions relative to the baseline for purposes of determining the expected benefits from the BPS as an average for the District. Thus, conducting this analysis for a 75 psig boiler would have no applicability in this regard. From a technical feasibility standpoint, the primary issue which may arise when specifying an economizer approach temperature for a lower pressure boiler would be a potential to excessively heat the boiler feedwater such that boiling or "steaming" occurs in the economizer at high levels of heat recovery (since the steam saturation temperature is lower for lower pressure steam). As explained in the BPS evaluation, although the District's thermal analysis indicates that an economizer-equipped 75 psig boiler should be able to achieve a 20 ^{o}F economizer approach without economizer steaming when heating deaerated boiler feedwater, a criterion has been added which addresses this by limiting the extent to which heating of the boiler feedwater is required (no higher than 30 ^{o}F below the steam drum temperature).

15. **Comment**: Please clarify if it is intended for the rated heat-input threshold to be different or the same in BPS elements numbers 2 and 4. The BPS is presented in the staff report as concurrent measures for boilers in the category of 75 psig or greater, yet two of the BPS elements identify only a subset of the category: BPS element number 2 states for "20 MMBtu/hr or greater," and BPS element number 4 states, "in excess of 20 MMBtu/hr and a rated steam pressure of 125 psig or greater". It is not clear whether it was a conscious decision to specify BPS elements for boilers rated at *"20* MMBtu/hour and greater" versus boilers "in excess of 20 MMBtu/hour'. What is clear is those boilers 20 MMBtu/hour and greater are a different category than those boilers less than 20 MMBtu/hour. SoCalGas believes the District should have at least two categories of boilers (if not more) in this class rather than just one based on rated steam pressure. (SCGC)

Response: The District's intent was for BPS elements 2 and 4 to have the same heat input threshold (greater than 20 MMBtu/hr). The document has been corrected to reflect this. The District believes that subcategories of this category and the associated BPS specification are sufficiently clear as stated. No additional provisions have been identified which would justify creating additional categories within this class of equipment and the current designation of this category has been retained.

16. **Comment**: Greater consideration is needed for all possible types of boilers that meet the criteria for the BPS category with steam pressure rating of 75 psig and greater. Another concern of using 75 psig as the lower limit for this BPS category is there are boilers with a heat input of as low as 500,000 Btu/hour (0.5 MMBtu/hour) that exceed a steam pressure rating of 75 psig. The baseline assumptions for such small units are very different from those with 20 MMBtu/hour

heat input and even than those with 5 MMBtu/hour heat input. SoCalGas suggests the District add a heat input rating to the steam pressure rating for each category such that the assumptions used in the representative baseline, technologically feasibility and economic analysis match the boilers in the stated category. This case also supports our request that this class needs more than just one BPS category. (SCGC)

Response: Since the BPS is strictly concerned with the "Best Performance" with respect to GHG emissions, addressing a different type of boiler separately would only be applicable in the event that a particular boiler design is exclusively required for a specific application. As a result, it is entirely possible that the BPS will, in effect, indirectly specify a particular type of boiler if it is inherently more efficient. Since this BPS is of a general nature, boiler applications requiring specific boiler technology would have to be considered in the future as a separate BPS. At this time, the District has not identified any such applications. The District believes that the proposed BPS, as currently stated, is sufficiently general to be applicable to typical firetube and watertube boilers.

The District's plans to structure this BPS to reflect achieved-in-practice technology for boilers with rated heat input greater than 5 MMBtu/hr. Boilers rated 5 MMBtu/hr or less which are fired exclusively on natural gas or LPG do not require permits by the District and thus this BPS would not be applicable to these units. Boilers rated 5 MMBtu/hr and less that require a District permit would be fired on fuels other than natural gas or LPG. Since this BPS will be applicable only to natural gas or LPG, the BPS would thus not be applicable to these units as well. A separate BPS will be developed to cover boilers fired with alternate fuels.

17. **Comment**: The 2002-2004 representative baseline operation should be recalculated. There s a fundamental assumption for the representative baseline operation that appears to be incorrect. On pages *6* and 7 of the staff report, the District assumes that this class and category of boilers for the baseline period of *2002*-2004 would have ultra-low NO, (oxides of nitrogen) burners operating with 30% flue gas recirculation meeting 9 parts per million volume (ppmv) NOx,. It appears this is based on the boilers meeting the NO, limits in Rule 4320 adopted October 16, 2008, as this is the boiler rule with a limit no higher than 9 ppmv NOx,. The earliest compliance date for Rule 4320 is July 1, 2007 for refinery units with total rated heat input greater than 110.0 MMBtu/hour. The next earliest compliance date in Rule 4320 is July 1, 2010. Clearly, this rule should not be used for the baseline period 2002-2004. Rule 4306 (Phase I11 of the boiler rules) adopted September 18, 2003 has a NOx limit range from 9 ppmv to 30 ppmv NO, (except for refinery units >110.0 MMBtuJhour input that have a 5 ppmv limit), and an earliest compliance date of June 1, 2005. Therefore, this rule is also not appropriate for calculating a three year average for the baseline period 2002-2004. SoCalGas believes that the boiler rule most appropriate for the baseline period 2002-2004 is Rule 4305 Boilers, Steam Generators, and Process Heaters – Phase II. The latest compliance date for this rule was May 31, 2001, so boilers would have complied for the whole baseline period of 2002-2004. The lowest NOx limit in

this rule is 30 ppmv NOx,, while low-use units did not have a NOx limit. SoCalGas requests that the District use Rule 4305 and its permit database to determine what type of equipment and operational parameters were in place during the baseline period of 2002-2004, and then reevaluate the representative baseline operation. (SCGC)

Response: A value of 9 ppmv was inadvertently stated in the BPS document. The District concurs that 30 ppmv is the correct NOx value for the Baseline Period which is consistent with the 30 % FGR rate quoted. Therefore no recalculation is necessary.

18. **Comment**: SoCalGas requests that the District lower the minimum thermal efficiency to a more realistic value. First, attaining incremental efficiency gains above current generally acceptable efficiency levels is subject to the limitations of the process served by the boiler. In order to attain very high thermal efficiency, all relative factors such as blowdown rate, wall losses, and product streams capable of accepting the otherwise "wasted" boiler stack heat have to exist within the steam system. The project profile in Appendix *5* and discussed on page 19 is not applicable to most boiler applications in the San Joaquin Valley. To our knowledge, there are only 5 boilers in the size range of 650,000 lbs/hour or greater in our San Joaquin Valley service territory (only the southern portion of the district jurisdiction), and in our experience very few customers have the ability to reject boiler stack heat in such quantities such that 95% efficiency could ever be obtained. SoCalGas is unaware of any boiler operating in the state of California that meets 95% thermal efficiency. One of our large pharmaceutical customers in southern California just installed a Super-Boiler with emerging technology incentive funding. Everyone involved in the project is very excited that test results have
proven out the technology with operating efftciencies in the 93% range. This project is truly a state-of-the-art "gold standard" for boiler installation. The project utilizes an innovative transport membrane condenser (TMC), developed by the Gas Technology Institute (Gn). Use of the TMC technology was a "test" boiler program with support from the natural gas industry, the US Department *of* Energy, the California Energy Commission, SoCalGas' Emerging Technologies program and GTI. Clearly, this is not a typical installation, and even it does not meet the stated BPS minimum thermal efficiency of 95%! The Super-Boiler is a special project of a consortium of groups (indicted above) who pool resources to test emerging technologies. The Super-Boiler technology is still under development and is far from being becoming commercially available. The cost of a system that has such a high efficiency as the Super-Boiler project is very, very high (greater than $1,000,000). Commodity based businesses like
those in the San Joaquin Valley, cannot necessarily afford state-of-the-art systems like those installed at a pharmaceutical or other high-tech company. (SCGC)

Response: As previously discussed, the intent of the 95% specification was not to necessarily require such an efficiency of any facility and was not stated as a "minimum" thermal efficiency in the document. This criterion was stated as the "maximum" thermal efficiency which would ever be required regardless of other specifications regarding recovery of energy from the boiler flue gas. To avoid the potential confusion, the District has revised the BPS to eliminate this specification.

19. **Comment**: The District should address facility space considerations, especially for rebuilding existing systems. Unfortunately, the BPS ignores space considerations. For example, in order to install adequate heat transfer surface to provide a maximum design approach of *20*° F temperature between the economizer flue gas outlet and the economizer inlet water, a large surface area economizer may be needed. This takes a lot of space, which may not be available, and increases equipment cost. (SCGC)

Response: The BPS is applicable to new installations only and the BPS document has been revised to reflect this applicability. Modification or replacement of existing boilers would not trigger any consideration of GHG emissions under CEQA unless there was an increase in permitted firing rate. Modifications or replacements of existing units which result in increased capacity (increased GHG emissions) will be covered under a separate BPS. Generally, projects installing new boiler facilities can accommodate the space requirements for increased heat transfer and therefore an analysis of space considerations is not applicable.

20. **Comment**: SoCalGas assumes that the equivalent energy recovery referenced in option 2 (of BPS element 1) is the minimum thermal efficiency improvement of 4% in the stated range of 4-10% depending on application specifics as discussed on page 13 of the staff report. (SCGC)

Response: Equivalent energy recovery is that which is equal to the heat recovery from the boiler flue gas (the same stack temperature) which would have been attained by installing the prescribed economizer. The BPS statement has been modified to clarify this requirement.

21. **Comment**: SoCalGas believes there should be a combined energy efficiency alternative in place of the combination of all four BPS elements. Although BPS element
Number 1 has an equivalent energy-recovery alternative, it is for only one of the 4 elements. An example of why this would be beneficial is as follows: The variable frequency drive electric motors (discussed on page 16) work well with load-following boilers, but have little value when the motor powers a fan or pump that only operates at one speed or just at full speed. This requirement is very prescriptive, and may be neither needed nor cost effective for a specific application. (SCGC)

Response: The District concurs that both BPS elements 1 and 2, regarding energy recovery from the boiler flue gases, should have an allowance for an equivalent alternative since there are a number of well-recognized alternatives to achieve a given level of heat recovery from the boiler flue gases. With respect to variable speed drives on electric motors (BPS element 3), the vast majority of all boilers operate with some level of turndown. In addition, combustion air fans are generally specified with design margin (typically 110% of normal). For units such as fans which are primarily working against dynamic pressure losses, a capacity of 110% requires a discharge pressure rating of $(110\%)^2$ or 121%. Thus, significant energy losses may be present even when operating at full boiler capacity. The District believes that essentially all VFD drive installations will provide energy savings relative to fixed speed drives regardless of the level of turndown. Establishing an energy efficiency alternative for items 3 and 4 is problematic due to the lack of available alternatives which are quantifiable and verifiable. Conceptually, the only feasible approach would be additional heat recovery from the boiler flue gases; however, an approximate thermal analysis by the District indicates that the economizer approach specified in BPS element #1 would have to approach 0 ^{o}F (infinite surface area) to achieve equivalent thermal efficiency to offset elements 3 and 4 and therefore would not be feasible. Based on this, no equivalency options will be introduced for elements 3 and 4.

22. **Comment**: Besides 'being very prescriptive, limiting the maximum oxygen content in the stack gas to 2% may lead to unsafe boiler conditions. The District acknowledges potential unsafe operating conditions including carbon monoxide formation, sooting, and explosions on page 15 of the staff report, Tuning the boiler in a conservative manner to assure stable and safe operations seems little price to pay when the potential for life threatening explosions exist with too little oxygen! SoCalGas requests that the District assure that any maximum oxygen content setting provides for safe boiler operation at all times. (SCGC)

Response: The District concurs that a 2% O2 concentration may be difficult for all facilities to achieve safely. The BPS will be revised to specify operation at 3% O2.

23. **Comment**: Limiting the flue gas recirculation to no more than 10% of the total flue gas volume prioritizes green house gas reductions over that for criteria pollutants.
On page 15 of the staff report, the District indicates that Selective Catalytic Reduction (SCR) for NO, will likely be used, as higher excess air (above 10%) may be needed for ultra-low NOx burners. Although this BPS element is limited to boilers greater than 20 MMBtu/hour heat input, some operators of units greater than 20 MMBtu/hour heat input are planning to use ultra-low NOx burners over SCR to comply with Rule 4320. Considering the enhanced option compliance date in Rule 4320 is January 1, 2014, this BPS will preclude such an option, and operators may have capital funding plans in place that cannot accommodate such a change. In addition, there is no evaluation of the

emissions of an SCR ammonia system, nor the increase in mobile source emissions from ammonia delivery. Please address these issues as it counter to the District's position *of* not favoring one technology over another and using emission standards rather than specific, prescriptive technology. (SCGC)

Response: Per the District's staff report, the requirement for BPS with respect to criteria pollutants is that the proposed BPS will not result in an increase in criteria pollutant emissions. The proposed BPS meets this criterion in that the proposed GHG emission reduction measure limiting FGR has been demonstrated to be achieved-in-practice without resulting in an increase in criteria pollutant emissions. Please see the response to comment #4 for additional District response on this topic. With respect to compliance dates and options for compliance with District Rule 4320, please note that the BPS is not a regulation and does not require compliance for existing operations. The BPS is only applicable to projects including new boilers which trigger consideration of CEQA as a result of a net increase in GHG emissions. The District will revise the BPS to include evaluation of GHG emissions associated with manufacture and transport of ammonia.

24. **Comment**: In a rule that has such wide reaching cost implications can you comment on the lack of long term, third party, data to support the efficiency numbers presented. Rather than using sales brochures from companies (RF McDonald and Nationwide) that have an interest in selling equipment that will result from the BPS requirements, should not the real gains be based on third party, long term (at least 12 months) data to document both efficiency gains through an operating year as well as identify reliability issues. This data should also present capital cost data as well as effect of the technologies listed on operating and electrical usage (pressure drop). I would suggest that this long term operating data be presented required for the technologies listed below to verify the technology is sound and the results can be sustained over long time periods. (URS)

Response: In the comment, the BPS is incorrectly referred to as a ”rule”. Rather than a rule, BPS is a GHG emission standard which facilitates the determination of “significance” of greenhouse gas emissions for new projects under CEQA. In this role, it represents one of several options which may be proposed by a project applicant to address new GHG emissions. Additionally the District's BPS does not fundamentally require a specific thermal efficiency. Please see the response to comment #18 with regard to boiler efficiency as stated in the BPS. The BPS is a design specification (based on maximum firing rate) for installation of new facilities which must be based on achieved-in-practice technology. Supporting documentation required, based on these criteria and on the definitions of BPS and “achieved-in-practice” in the District's staff report, must necessarily demonstrate that the design standard has been applied and is successfully operating at existing facilities. The District's BPS document clearly states that attached vendor documentation is provided only as examples to illustrate the technology concept and does not refer to them as documentation of achieved-in-practice status. The District has amended the BPS evaluation to include a list of operating facilities where successful implementation of the design standard has been achieved.

25. **Comment**: For conventional economizers, performance is typically about 70 F approach at full load. At 20% load the approach is at best about 20 F. This means about 5X more surface area is required to achieve a 20 F approach at full load. For example for a normal economizer the full load stack temperature is 300 F, to reduce to 260 F this would require 5X the surface area for a efficiency gain at 3% stack O2 of 1.2%. Although this is possible, does it make sense for a 1.2% gain? Is there any data to support long reliable term operation of an economizer of this size? For this low an approach temperature how much does the performance fall off as the tubes get dirty. What is the trade off in cost, pressure drop and fan size versus thermal efficiency savings. Based on long term operating data with a 20 F approach design economizer how much out of service time is expected versus a conventional economizer. What problems have been experienced with a 20 F approach design economizer. (URS)

Response: The District's analysis indicates that a 20 ^{o}F approach economizer heating boiler feed water would have a log mean temperature difference which is approximately 60% of that of an economizer with a 70 ^{o}F approach. For a first approximation, assuming heat transfer coefficients are equal, this would lead to a relative size for a 20 ^{o}F approach which is about 1.7 to 1.8 times larger than required for a 70 ^{o}F approach. Since the District's determination of BPS is based on "achieved-in-practice" criteria, a cost effectiveness determination in terms of $ per Btu recovered has not been performed nor is it required since elements determined to be achieved-in-practice are assumed to be cost effective. However, it should be pointed out that a 1.2% gain in efficiency represents significant reductions in GHG emissions and significant savings in fuel costs for the operator. A detailed analysis of long term relative operating costs for varying degrees of energy recovery is not a part of the evaluation and determination of BPS. Please see the District's response to comment #24 for further discussion regarding determination of achieved-in-practice for BP.

26. **Comment**: What long term operating data is available to support operation of a two stage economizer in a variety of plant operating conditions. How large does each stage of the economizer become to achieve stack temperatures no more than 20 F above the inlet water temperature? What is the trade off in pressure drop and fan size versus thermal efficiency savings. For each plant you need to look at what pressure steam is available for the DA tank. If you heat the water too much in the first stage, high pressure steam may be required for the DA tank instead of low pressure steam negating efficiency advantages. How will these sometimes very complex issues be handled in the permit review. (URS)

Response: Please see the response to comment # 25 for the District's discussion concerning long term operating data and economizer physical size. With respect to heating boiler feed water flowing to a DA tank, the BPS addresses this as follows: For units 20 MMBtu/hr and less and equipped with a DA, an economizer operating between the DA tank and steam drum is the only requirement and thus this issue could not arise. For units greater than 20 MMBtu/hr and equipped with a DA. heating of feedwater to the DA is only required if the temperature is 150 ^{o}F or less which provides an adequate margin to avoid overheating the feedwater going to a 5 psig DA tank (227 ^{o}F). This temperature threshold might also incentivize facilities to optimize heat and condensate recovery elsewhere within the facility to avoid the impact of a second stage economizer. By addressing these issues in the BPS, impacts on permit review will be minimal.

27. **Comment**: The second major area where we question the approach in the BPS, is the restriction on FGR and/or stack O_2 without any restrictions on other components of the system including the pressure drop through the burner. Although high FGR rates do increase fan horsepower, so can SCRs, high pressure drop burner/boiler designs, heat recovery equipment (economizers and air heaters). Why does the BPS restrict one component of a boiler system that can increase fan horsepower but ignore the other components. For example, if you have a conventional burner operation at 40 ppm NOx with 10% FGR, but the burner is designed for a 16" WC drop with 10% excess air and 10 % FGR and the boiler is designed for a 12" drop the total system pressure drop is 28" WC and the flow is 1.1x1.1 = 1.21. The fan horsepower required is then proportional to 1.21x28 = 33.9. If you compare this to a burner operating with 40% FGR and 20% excess air with a 6" WC burner drop and a 5" boiler drop the equivalent fan horsepower is 1.2x1.4x11 = 18.4 or only 55% of the pressure required for the high pressure drop burner/boiler operating with low excess air and 10% FGR. SCR pressure drops can vary with design, with typical pressure drops ranging from 1" to 6" WC. Again why does this document address FGR/excess air rates without addressing these other factors that can have a great influence over pressure drop. (URS)

Response: The BPS has included a restriction on FGR rates due to the significant cumulative reductions in indirect GHG emission which accrue from this relatively straightforward measure (see the District's response to comment #22 with respect to excess air). This is based not only on increased pressure drop associated with FGR as mentioned but also includes consideration of a 40 to 50% increase in volumetric flow through the fan due to the combined effects of increased mass flow and temperature for the system fan when operating with the high FGR rates required to achieve a 5 ppmv NOx emission rate with burner technology only. In addition, operation with high FGR rates is generally detrimental to boiler dynamics which often results in a requirement to operate at increased excess air levels to maintain stable operation, impacting boiler thermal efficiency and further increasing GHG emissions. While restricting FGR rates is a significant, straightforward and achieved-in-practice GHG reduction measure, the restriction of pressure drops for specific individual equipment items would require the District to develop significant expertise with respect to the detailed engineering and design of these subsystems (which is not the District's expertise or mandate as an agency). Such restrictions would run the risk of producing less than optimum results since they may have unintended consequences in the configuration of the system when the design, fabrication and site specific factors are taken into account. In addition, such restrictions would be expected to individually produce significantly less benefit in terms of GHG emission reductions when compared to a more global restriction on FGR operation. Pressure drop is only considered in the BPS evaluation in the context of determining potential reductions in indirect GHG emissions which may accrue as a result of BPS implementation relative to the baseline.

28. **Comment**: Some plants have multiple steam pressure headers and use turbine driven FD fans to drop the pressure from the high pressure header to the low pressure header. This energy is virtually free since if the pressure were not dropped across the turbine it would be dropped through a valve or regulator. Why should these boilers be limited in the amount of FGR/excess air required if it does not affect the overall plant (GHG) emissions? (URS)

Response: Considering that the BPS is applicable to new facilities only, it is reasonable to assume that the steam distribution system for such a facility will be designed for optimum efficiency while incorporating the reduced energy benefit associated with reduced FGR rates. It is doubtful that an optimized design for a new facility would incorporate a wastage of steam energy which would then provide "free" FGR operation. In an optimized facility design, reduced FGR rates would still provide substantial GHG emission reductions.

29. **Comment**: Operation at 2% stack O_2 (dry) is difficult to maintain without excessive CO emissions. The efficiency saving from 2% to 3% O_2 is only 0.2% at a stack temperature of 260 F and is even lower at lower stack temperatures. Can the O_2 be 5% at 90% load? Will continuous monitoring and reporting be required? Since during a source test it is unlikely the boiler is operating at 100% firing rate, how will the 2% O_2 condition at full load be enforced and what is the purpose if there is no restriction on O_2 at say 90% firing rate and boilers rarely operate at full load. (URS)

Response: As previously mentioned, the District concurs that a 2% may be difficult to achieve for all facilities. The BPS will be revised to require a 3% O_2 concentration in the stack which represents what is traditionally considered to be "efficient" operation. New units operating with O_2 trim systems can achieve this performance on a continuous basis except during startup and shutdown periods. This requirement will be implemented as a permit condition limiting O_2 concentration to a maximum of 3% except during startup and shutdown.

30. **Comment**: If the goal is to decrease GHG emissions shouldn't you just be setting standards for maximum FD motor size and perhaps stack temperatures relative to feedwater temperatures. Let industry and vendors figure out how to do it best. (URS)

Response: The BPS precisely matches the approach suggested concerning setting a standard for stack temperature relative to feed water temperature (economizer approach temperature). With respect to setting standards for fan motor sizes, the District considers this approach impractical and excessively prescriptive with respect to mechanical and system design details and believes that it would be subject to the same issues as discussed in the District's response to comment #27.

31. **Comment**: The district analysis does not account for increased pressure drop from 5X larger economizers, SCR, etc. Why are these factors not included in the analysis. These factors can be significant. (URS)

Response: The District has revised the determination of potential reductions in indirect GHG emissions which may accrue as a result of BPS implementation relative to the baseline to include specific considerations of economizer and SCR pressure drop.

32. **Comment**: What savings can be produced by advanced use of plant efficiency and process improvements and/or the use of high pressure boilers and creative use of back pressure turbines. Many boilers have no control or heat recovery from blowdown. Why is this not addressed? These types of improvements would not only reduce GHG from new boilers but potentially from all boilers. (URS)

Response: Refer to the response to comment #1 which addresses the District's philosophy with respect to facility efficiency improvements versus boiler efficiency improvements. With respect to boiler blowdown, the District concurs that GHG emissions from boiler blowdown losses should also be addressed. A reduction measure will be added to the BPS in this regard.

33. **Comment**: Why does the document not address fan mechanical efficiency? There can be large differences in mechanical fan efficiencies ranging from less than 50% to greater than 80%. Specifying high efficiency fans has much more potential than specifying premium motor usage for reducing fan horsepower. (URS)

Response: Specifying fan efficiency in the BPS would again trigger a number of pitfalls mentioned in the District's response to comment #27, concerning issues associated with prescribing detailed mechanical design details for system components. The District's approach is to set general standards which fundamentally and substantially reduce the flow and pressure requirements for the fan (which would apply to all boilers regardless of the specific flow and pressure drop requirements) and then rely upon the fan specialist to deliver the most efficient product within that framework.

34. **Comment**: Why is an air heater, particularly condensing air heaters, rejected as BPS. An air heater does potentially increase NOx but if an SCR is used the NOx can be controlled. Depending on the feedwater temperature the air heater may be a way of obtaining the same or higher efficiency at a lower cost and lower pressure drop than an economizer with a 20 F approach temperature. There is at least one boiler with a conventional economizer, condensing air heater and SCR operating in the Valley with an average efficiency of about 90% (higher in the winter lower in the summer).. (URS)

Response: The BPS does not reject air heaters. The BPS specifically allows use of any technology or combination of technologies which result in the same amount of energy recovery from the boiler flue gas as the given economizer arrangement. The BPS evaluation simply discarded air heaters as a technology basis for establishing the achieved-in-practice performance for the BPS determination due to a lack of universal applicability.

35. **Comment**: On page 15 it is stated "the amount of excess O2 is approximately proportional to the efficiency lost; that is 3% excess O2 means approximately a 3% efficiency drop for the boiler." This is not true since heat is recovered in the boiler and the colder the stack temperature the less the efficiency loss. For example at 300 F stack temperature the efficiency difference from 0 to 3% stack O2 is about 0.7%. (URS)

Response: The District concurs that the impact of excess air on boiler efficiency is overstated in the discussion on page 15. The BPS evaluation has been corrected.

36. **Comment**: On page 16 it states " FGR has a negative impact on boiler performance similar to excess air and required substantially more HP to operate". With FGR the energy used to heat the FGR is recycled back to the burner while with excess air the energy used to heat the air goes up the stack. The effect of FGR on the boiler overall thermal efficiency depends on the amount of radiation heat transfer surfaces versus convective. Since FGR reduces flame temperature the radiation heat transfer is less but since the velocity of the flue gas is higher the convective heat transfer is increased. On some boilers you can see a very slight drop in efficiency on others a small increase when FGR is used. The effect is normally very small and normally cannot be measured.. (URS)

Response: The District concurs that the impact of FGR on boiler thermal efficiency (and the associated direct GHG emissions) is not significant within the context of the BPS evaluation. The BPS discussion has been revised to reflect that the primary efficiency impact of FGR is the fan power requirement (indirect GHG emissions).

37. **Comment**: On page 13 it states, "the use of a 2nd stage economizer is a common practice to further enhance energy recovery". I personally deal with hundreds of gas fired industrial boilers in California and through the US, primarily in the size range 40 to 500 klb/hr steam. In all the boilers I have worked with I have never seen a two stage economizer in use although I see many condensing economizers. (URS)

Response: The District concurs that the use of the term "common use" is vague. The District has revised this statement to note that "the use of a 2nd stage economizer is an "achieved-in-practice method" to further enhance energy recovery".

38. **Comment**: Only the most careful reading of the proposed BPS reveals that the desired efficiency metrics can only be achieved under a very narrow range of operating conditions. The literature provided to support the claim that this BPS is "achieved in practice" assumes very optimistic operating scenarios such as continuous operation at full load, ignoring start-up/shut-down inefficiencies, a near unlimited supply of cold water and a productive use for excess hot economizer water. At this time, we are unaware of any boilers that have achieved the proposed BPS in-practice. We respectfully request that the SJVAPCD provide listings of actual installations with source test and as-built thermodynamic efficiency measurements demonstrating the proposed BPS has been achieved. (CWCCG)

Response: The BPS does not directly require any specific efficiency and thus no assumptions concerning specific operating scenarios are made. Consideration of BPS has been limited to requiring a level of heat recovery from the boiler flue gases relative to the water supply temperature to the boiler (20 ^oF approach). Additionally, the BPS is a design standard. In this scenario, boilers equipped with BPS and operating with 100% cold make up water will have significantly higher design efficiencies relative to those operating with hot water return. A list of facilities operating with economizers designed for a 20 ^oF approach has been attached to the BPS evaluation. Please see the District's response to comments #2 and #6 for further discussion.

39. **Comment**: Additionally, the SJVAPCD Final Staff Report, Addressing Greenhouse Gas Emissions Impacts under the California Environmental Quality Act mentions that the proposed BPS should meet an economic feasibility test1. The documents provided for this BPS do not include this calculation, nor has the District, as of yet, defined what "economic feasibility" means in this context. We request that the District address this vital issue before implementing this (or any other) BPS. (CWCCG)

Response: Please see the District's response to comment #11.

40. **Comment**: Boilers combusting carbon-neutral fuels like sewage digester gas and landfill gas face unique operational and technical challenges, and cannot achieve the thermal efficiencies of natural gas boilers. Contaminants not normally found in natural gas can frustrate achieving high thermodynamic efficiencies from combusting landfill/sewage biogases. Siloxane contaminants, nearly ubiquitous in these gases, can foul most heat recovery surfaces such as fins on the economizers. Additionally, landfill and sewage digester gases are often saturated with moisture that must be removed prior to combustion. Both water removal and costly siloxane pretreatment would be required to sustain maximum thermal efficiency. The presence of this energy-intensive conditioning equipment would further erode process efficiencies gained from installing two-stage economizers, etc., thus the comparison to the baseline natural gas unit is
moot. Additionally, simple thermodynamics dictates that biogas fuels, which, pre-combustion, contain 30 to 50% bio-generated carbon dioxide, cannot achieve the same flame temperatures as natural gas. A major driver of boiler efficiency is the temperature differential between the flame front and the temperature of the steam generated. This differential is lower when biogases are combusted in place of fossil fuels, and thus the thermodynamic efficiency is decreased proportionally.
Finally, the proposed BPS efficiency metric of 95% has not been achieved-in-practice for biogas fuels. Based on supporting documentation provided with the BPS, the expected emissions reductions of 7% were clearly calculated from a natural gas boiler baseline, hence the proposed BPS should not be applicable to biogas fired boilers. We ask that the District concur with this analysis and state more clearly that the proposal does not apply to biogases. (CWCCG), (RFM)

Response: The District concurs that biogas boilers should be considered under a separate BPS. The BPS has been modified to indicate that it is applicable to natural gas and LPG-fired units only.

41. **Comment**: The SJVAPCD Final Staff Report, Addressing Greenhouse Gas Emissions Impacts under the California Environmental Quality Act recognizes that renewable fuels reduce GHG emissions when they displace fossil-fuels. Furthermore, in the California Low Carbon Fuel Standard lifecycle analysis of alternative fuels, landfill gas [CNG] has the lowest carbon intensity value of nearly every other fuel. Accordingly, we respectively request that SJVAPCD consider the use of renewable fuels as a potential alternative BPS for boilers. The Final Staff Report (p. 84) mentions that biogas combustion in lieu of fossil fuels could be considered an alternate approved technology. However, it also mentions that this option has not been achieved-in-practice. There are at least two installations combusting landfill gas in high pressure boilers at the Puente Hills and Palos Verdes Landfills, and a long history of biogas combustion in many devices such as LP boilers, engines, turbines, etc. We suggest that the District keep an open mind when reviewing these projects and recognize that these devices, though they may not achieve the same thermodynamic efficiency as their fossil fuel cousins, will result in radically lower GHG emissions due to the nature of the fuel. (CWCCG)

Response: Since there are complex issues involved with the consideration of biogas-fueled boilers as well as the generation of biogas, the District will consider this under a separate BPS determination.

42. **Comment**: The requirement to achieve a 29% reduction from the business as usual (BAU) condition prior to 2020 is inappropriate when the District's own analysis shows that even today's "best" performing technology can only achieve a 7% reduction. Such a requirement for the BAU condition would push every project that cannot meet the proposed BPS into an EIR. Moreover, the AB 32 Scoping Plan does not require 29% reduction from each and every sector; different sectors will reduce more, some less4. Since the District's own analysis demonstrates that these boilers cannot approach this goal, it should investigate flexible alternatives for lead agencies.
Also, it is not clear to us how GHG credits could be used to mitigate a project's GHG emissions below significance if neither the BPS nor BAU standards can be met. Unless it has completely netted-out its emissions, no lead agency could ever be assured that they have fully mitigated below significance. Unlike other proposals such as that advanced by the SCAQMD, it is not clear if there is a mitigation off-ramp to avoid a significance determination. We ask that the District demonstrate how the use of emission reduction credits, such as those held in their Rule 2301 bank, could be used by lead agencies to potentially mitigate below a level of significance. (CWCCG)

Response: Comment noted. Since this comment is of a general nature and not specifically directed at the proposed BPS for boilers, the District will not respond to this comment as a part of this document.

43. **Comment**: It is my hope that any ruling you decide to endorse will be a voluntary rule as a starting point. This will give time to determine the effect it will have on industrial boiler applications as there will be an increased cost of the higher efficiency equipment and maintenance. There are three companies that I personally know about who are moving this year out of the State of California. This is due to the South Coast Air Quality Management District NOx emission ruling. It probably amounts to a loss of 300 – 400 jobs and as you know this financial burden will certainly drive other companies from the State of California. (SCB)

Response: The BPS is fundamentally a test of significance and is not a rule. This BPS will only be applicable as a design standard for new boilers and thus should not impact existing business operations.

44. **Comment**: It would be ideal to have each facility evaluated to see if they have the heat transfer requirements that could assist them in achieving the higher efficiencies of this standard. This would also allow time for the SVAPCD to make a comprehensive examination of the impact on companies vs. the environment.

The 95% efficient steam boilers achieved in practice are once through units and have a need of 100% make-up water plus a separate heat load for hot water using 60 – 70° F inlet water through a condensing economizer or a wet economizer. These projects are fairly rare and would only be 1- 2% of the total projects unless the project is a hot water condensing boiler. (SCB)

Response: Please see the District's response to comment #'s 1 and 2.

45. **Comment**: The requirement for <10% FGR and 2% O2 will probably require a standard 30 or 40 PPM NOx burner with SCR system, which will add on additional costs to each project. Most of the boilers in your area already have installed Ultra Low NOx burners with 15-PPM NOx or less and they all require more than 10% FGR and run higher than 2% O2. All these burners would need to be modified or replaced and a SCR System added intensifying the costs. (SCB)

Response: Since the BPS applies only to new boilers, existing operations with low NOx burners would not be affected.

46. **Comment**: My experience in the field spans over 35 years and in that time I have only seen a few boilers operating at 2% O2 steadily 24/7. This includes boilers where they only operate at 2% for test operation and have to be readjusted for higher O2 to be reliable, especially large outdoor boilers. (SCB)

Response: Please see the District's response to comment # 22.

47. **Comment**: As mentioned above, it is my hope that you will be looking at each project on a case-by-case basis to ensure there is sufficient heat transfer load to achieve higher efficiency in the rate of 88% - 92%. If they cannot meet your requirements, will you allow them to meet a lower efficiency rate based on heat transfer load in their facility? (SCB)

Response: Please see the District's response to comment #'s 1, 2 and 18.

48. **Comment**: The 95% thermal efficiency for fully condensing boilers is very aggressive. A >90% figure would open up many more candidates to achieve this efficiency in their plant's particular operating process. (NBI)

Response: Please see the District's response to comment #'s 1, 2, 18 and 38

49. **Comment**: The 2% O2 figure for excess air might also be too aggressive in today's marketplace. Many burner manufacturers will currently guarantee 3% (especially when 40% FGR) but 2% does limit burner choices in the marketplace. (NBI)

Response: Please see the District's response to comment # 22

50. **Comment**: Maybe the 400F stack temperature was OK years ago but current catalyst technology can go down to 325F today. Stack temperatures for SCR catalyst are already currently proven in practice to commonly operate in the 300-400F range, especially on firetube boiler applications and/or at low fire conditions. See attached actual performance results from a 700HP firetube boiler. This unit has been in operation for over 2 years in the Central Valley. (NBI)

Response: The District assumes this comment is inferring that additional emission reductions might be achieved by extending the range of applicability of restrictions on use of flue gas recirculation. Although this might be possible in some applications, the District's opinion is that reducing FGR rate for boilers operating at 75 psig and above and with rated firing greater than 20 MMBtu/hr represents a realistic achieved-in-practice approach which will be generally applicable to all boilers in the specified range. Extensions of this measure to smaller, lower pressure boilers may be problematic and perhaps less than achieved-in-practice.

51. **Comment**: With regard to the Boiler BPS under consideration, Kern Oil & Refining Co. requests a category specific to refinery operations fired exclusively on refinery fuel gas. This type of category should be considered for process heaters in refineries as well as for boilers. The District has recognized the uniqueness of refinery fuel gas as compared to PUC gas in previous prohibitory rules such as 4306 and 4320. If refineries did not capture, condition and recycle refinery fuel gas to fire heaters and boilers, the off-gas generated from the refinery process would then need to be flared, which would be counter-productive to the reduction of criteria and GHG emissions. In addition, most refinery heaters are natural draft. Natural draft heaters are more energy efficient than mechanical draft heaters since natural draft heaters do not require electrical energy off the grid to power the mechanical draft motors. There are also CO monitoring and control systems such as the Bambeck System (see link below) that increases heater/boiler efficiency and fuel efficiency by applying automatic damper control to regulate flue gas oxygen content which increases heater/boiler fuel efficiencies. I'd like to add to the comments below that considering the high cost of the Bambeck type system of continuous monitoring linked to automatic controls, this type of control should only be considered for the larger heaters/boilers > 110 MMBtu/hr. For the smaller category of heaters/boilers < 110 MMBtu/hr Kern would recommend damper draft gauges with periodic monitoring (routine checks) of the CO, O2 and NOx.
(KOR)

Response: This BPS has been modified to indicate that it is only applicable to units fired exclusively on natural gas or LPG. Other comments/input will be responded to as a part of a separate BPS(s) for refinery heaters and boilers fired on specialty fuels.

Appendix F

Comments Received During the Public Participation Process (2nd Draft) and Responses to Comments

Stakeholders Written Comments:

California League of Food Processors and Manufacturers Council of the Central Valley (CLFP & MCCV))
Clayton Industries (CI)

1. **Comment: The two hour limitation on startup/shutdown for boilers with a rated fire duty of 20MMBtu/hr. (BPS3)**

Currently, the District allows for longer startup and shutdown times. Any company can request additional time for such and it is logged in the PTO. We would request that the District keep this option available. It is critical for large boilers to be started up slowly or damage will result to either the refractory or metal components. The metal needs time to warm up and expand. Additionally, NOx and CO levels fluctuate during start up on low fire and cause compliance considerations. (CLFP & MCCV)

Response: The District has further examined the proposed limit on oxygen concentration in the boiler exhaust and has determined that the limit is not generally achievable during any periods of low firing rate for the burner including startup and shutdown. The District has revised the specification to state that the O_2 limitation is only applicable to periods when the boiler exceeds 20% of maximum firing rate.

2. **Comment: District should allow for use of biogas if performance standards can be maintained.**

We support the District's recommendation on the use of alternate fuels. As facilities continue to push the envelope on innovative, "green" technologies, the conversion of waste products to biogas is becoming more prevalent. While in most cases biogas will not burn as cleanly as PUC natural gas, nevertheless it is a good use of material that otherwise might contribute even more GHG through other disposal options. We urge the District to be more flexible with these types of alternatives and concepts as long as performance standards are achievable. (CLFP & MCCV)

Response: Boilers firing biogas or other fuels may comply with this BPS in lieu of a fuel-specific BPS. Generally, units fired with natural gas and LPG are recognized as capable of achieving the lowest GHG emissions when compared to other fossil fuels or fuels from sources such as digesters, landfills or biomass combustion. Due to contaminants or combustion issues, use of these alternate fuels may require a less stringent BPS but in no case would they be expected to exceed the performance of a unit fired with natural gas or LPG. Where necessary, the District's intent is to establish a separate BPS category for these fuels to accommodate special characteristics. However, since the BPS for natural gas or LPG is considered to be the most stringent standard, applicants proposing to fire fuels other than natural gas or LPG may also propose to meet the BPS for natural gas/LPG in lieu of a fuel specific BPS in which case the District will consider the unit to be compliant with BPS regardless of the fuel proposed. An applicability statement has been added to the BPS to clarify this alternative.

3. **Comment: District 20°F approach (for economizers) is essentially dictating equipment preference instead of emphasizing results.**

The District's recommendations concerning Economizer System Criteria (BPS, 1, A) sets forth three design requirements for economizers on boilers with a steam rating of 75 psig and greater. We would prefer the District to set standards and let the industry determine how to meet them. (CLFP & MCCV)

Response: Rather than dictating any equipment preference, the District's BPS specification fundamentally only specifies the maximum temperature allowed for the exhaust temperature of the stack relative to the boiler feed water based upon the achieved-in-practice performance of an economizer transferring heat from the boiler flue gas to the boiler feedwater. The BPS specifically states that other equipment or design configurations may be used as long as the same level of useful heat recovery is attained. This could include the use of air preheaters or the recovery of low level heat from the stack for other uses, offsetting fuel usage in those applications.

The specification of maximum allowed exhaust temperature of the stack relative to the boiler feed water in lieu of a minimum overall boiler thermal efficiency is based on:

- Energy vented to the atmosphere through the boiler exhaust represents the preponderance of energy losses from the boiler. Any effective energy efficiency standard for boilers must either directly or indirectly result in a limitation of the temperature of the boiler exhaust. Other efficiency improvement options such as blowdown minimization/heat recovery or reduced excess air operation have significantly smaller impacts on boiler efficiency.

- It is impossible to establish a universally applicable performance standard based on a single thermal efficiency. This can be seen by considering that boiler operation with cold feedwater can achieve efficiencies approaching 95% while boilers operating with hot feedwater may not be able to exceed 85% efficiency even when equipped with the most sophisticated heat recovery systems.

Based on the above, the District's opinion is that the BPS specification does not significantly or unreasonably restrict equipment selection options for high efficiency boiler operation.

4. **Comment: Limiting Flue Gas Recirculation which increases NOx emissions requiring use of SCRs**

Limiting FGR on new units is probably reasonable as the District is unlikely to permit any non-SCR units in the future. Our concern is that the District is looking at only one part of the system instead of allowing each facility to utilize a system wide approach. Reducing FGR will limit fan size and reduce electrical horsepower but will also result in an increase in NOx. On the other hand, increasing the FGR will reduce NOx. Seemingly, any reduction in NOx would be worth the increased fan horsepower required.

Again, we would urge the District to set the standards and let the individual companies determine how best to comply. (CLFP & MCCV)

Response: Rather than looking at only one part of the system, the District's approach has been to examine all parts of the boiler and establish the best performance for each element. With respect to limiting FGR rates, the District's proposed reduction measure does not result in any change in NOx emissions to the atmosphere since the District's NOx emission regulations remain in effect regardless of the GHG mitigation approach. Conversely, operating with high FGR rates not only requires additional electric power production but typically also increases the fuel consumption in the boiler due to an increase in excess air required to stabilize the high FGR combustion process. Given a constant NOx concentration at the exhaust (5 ppmv per District rule), higher FGR operation may actually increase NO_x production.

5. **Comment: Recommending a 3% O_2 emphasizing energy savings over the 4% to 5% commonly used to help with boiler stability.**

Limiting to 3% O_2 may cause boilers to be unstable but most boilers today are designed to run at these limits. The District would do better to set the absolute limit to at least 4% to allow design and operational fluctuations. (CLFP & MCCV)

Response: The District has restated this requirement to indicate that it is a "design requirement" and not a fixed limit on operation. The District is implicitly assuming that facilities which have made capital investments for O_2 trim systems and efficient burners will be predominantly disposed to operate them in the most efficient manner to obtain the available saving and generate a return on their investment. To avoid potential safety issues, the BPS will not place a real time operating limit on O_2 concentration.

6. **Comment: District should credit facilities operating efficiently.**

Currently, many facilities, such as tomato processors, use steam driven turbines for powering pumps primarily due to the efficiency of the process. The steam is used once for power and the "waste heat" exhaust at a lower pressure is used as a heat source for the evaporator. This provides maximum efficiency and allows for significantly reduced electrical demand. For total plant efficiency this is the best way to operate. Other facilities also have developed other means of utilizing this "waste" heat, but all should receive some form of credit as this is clearly an efficiency strategy and maximizing the energy generated from the boiler. (WZI)

Response: Although the BPS determination is limited to design and performance elements of the boiler itself, the District's policy for addressing greenhouse gas emissions from a proposed project allows consideration of other options related to efficiency improvements at the facility in lieu of meeting BPS (see District Policy APR 2005). A proposed new boiler would have the option of either meeting the BPS or, alternatively, demonstrating that 29% of the project's greenhouse gas emissions have been mitigated by other efficiency improvements at the facility, measured as emission reductions from the 2002-2004 baseline period.

7. **Comment:** Steam generators (as opposed to conventional drum boilers) are not capable of meeting the requirements of BPS element #3 (limited excess air and flue gas recirculation) while still complying with the District's NOx emission regulations. Due to the counter flow design of these units, they are inherently more efficient than conventional boilers in reducing the stack temperature of the unit which usually results in a temperature too low for operation of a selective catalytic reduction (SCR) unit for controlling NOx emissions. All NOx control options other than SCR either require substantial excess air or FGR to meet District regulations. Although steam generators cannot meet this BPS element, they offer considerable energy efficiency savings in other areas when compared to conventional boilers. These include:

- Higher basic efficiency due to the counter flow design
- Lower fuel firing during hot standby and warm-up since these units start up in a few minutes versus hours required for conventional drum boilers
- Boiler blowdown is less than 10% of that of a conventional boiler
- Radiation and convection losses are less due to the compact design (less surface area per pound of steam).
- Steam quality is usually 99.5% in a steam generator versus 98% typical for a drum boiler due to the high efficiency external steam separator used on steam generators. The recirculation of an additional 1.5% moisture results in efficiency losses.

Additionally, steam generators are typically a requirement in hazardous duty environments due to their inherently safer design (no large drum of steam contained in the boiler). (CI)

Response: The District acknowledges that BPS element #3 would not be generally applicable to steam generators due to potentially low flue gas temperatures. Since this BPS is directed exclusively to boilers, not all of the stated requirements are necessarily applicable to steam generators. The District will prepare a separate BPS for industrial/commercial steam generator applications to address the specific characteristics of these units.