San Joaquin Valley
Unified Air Pollution Control District

DRAFT Best Performance Standard (BPS) x.x.xx

<table>
<tr><td>Class</td><td>Gaseous Fuel-Fired Boilers</td></tr>
<tr><td>Category</td><td>Existing Boilers (Retrofit), Fired Exclusively on Natural Gas or LPG</td></tr>
<tr><td rowspan="2">Best Performance Standard</td><td>Applicability Note: Existing Boilers (Retrofit) 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 three elements of this BPS (items 1, 2 and 3 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. Equivalent heat recovery systems may utilize recovered heat for purposes other than steam generation provided such uses offset other fuel usage which would otherwise be required.

A. Except for boilers subject to the requirements of item B below, 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) 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 rated steam pressure less than 75 psig and a water supply temperature of 170°F or greater, the boiler shall be designed, in lieu of the requirements of item A above, to achieve a flue gas temperature no greater than the sum of the steam saturation temperature ($^{\circ}$F at the steam drum operating pressure) plus 100°F.

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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	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 a boiler blowdown rate exceeding 8 % of steam production, the boiler shall be equipped with an automatic boiler blowdown control system which will minimize boiler blowdown while controlling dissolved solids in the boiler water at an optimum level.

Percentage Achieved GHG Emission Reduction Relative to Baseline Emissions	**4.1%**

District Project Number	C-1100388
Evaluating Engineer	Manuel Salinas
Lead Engineer	Joven Refuerzo
Public Notice: Start Date	April 12, 2012
Public Notice: End Date	May 11, 2012
Determination Effective Date	

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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.

C. Determining Project Significance Using BPS

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

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

II. Summary of BPS Determination Phases

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

BPS Development Process Phases for Gaseous Fuel-Fired Existing Boilers (Retrofit), Fired Exclusively *on Natural Gas or LPG*			
Phase	**Description**	**Date**	**Comments**
1	Initial Public Process	09/30/10	The District's intent notice sent by email to interested parties registered on the District's GHG web site for this class is attached as Appendix B. Comment received during the initial public process with District's responses are attached as Appendix C.
2	BPS Development	N/A	See Section III of this evaluation document.
3	Public Participation: Public Notice Start Date	04/12/2012	The District's draft BPS determination was posted on the date indicated. The District's notification is attached in Appendix D.
4	Public Participation: Public Notice End Date	05/11/2012	

III. Class and Category

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

- Boilers represent a distinct operation (indirect heat transfer from combustion to heat or boil water) when compared to all other permit units currently regulated by the District.
- The District already considers this a distinct class with respect to Best Available Control Technology (BACT) for criteria pollutant emissions.
- This is a distinct class with respect to the District's prohibitory rules for criteria pollutant emissions (Rules 4306 - 4308 and 4320).
- The District's current prohibitory rules currently only allow gaseous fuel firing (with liquid fuel allowed as a backup only for PUC natural gas during curtailment periods) or solid fuel-fired boilers (Rule 4352). Gaseous fuel fired units differ substantially from solid fuel units with respect to design requirements and thus are considered to be a separate class.

Gaseous Fuel-Fired Existing Boilers (Retrofit), Fired Exclusively on Natural Gas or LPG is recognized as a distinct category of the class *Gaseous Fuel-Fired Boilers* based on the following:

- Gaseous fuels other than natural gas or LPG may have characteristics which will limit certain GHG emission reduction measures and therefore the firing of natural gas or LPG is considered to be a separate category.

- *Boilers which are existing, typically have a greater number of site-specific considerations (such as boiler geometry and space limitations) which may limit the application of certain types of GHG emission reduction technology.*

- Natural gas-fired hot water boilers (or hydronic boilers) are a separate boiler category and are not covered by this BPS since their operation is substantially different when compared to boilers producing steam. Since they only produce hot water rather than steam, they have a significantly larger boiler feedwater flow relative to the boiler flue gas when compared to units which produce steam. Additionally, these units do not employ boiler blowdown since they do not control water chemistry in a steam drum.

IV. Public Notice of Intent

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

Comments received during the initial public outreach are presented in Appendix C. 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 *Gaseous Fuel-Fired Existing Boilers (Retrofit), 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 rated less than 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.

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

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.

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). The stack temperature is calculated to be approximately 380 ^oF for this case.
- Convection/radiation loss from the boiler is assumed to be 0.5% of fuel firing.
- Stack O2 concentration is 4.5% with 30% FGR.
- 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 (See Appendix E), the following quantities are applicable:

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

  - Net steam production is 739.4 lb/MMBtu fired or a Specific Fuel Consumption (SFC) of 1,000,000/739.4 = 1,352 Btu/lb steam
  - Flue gas rate is 12,587 scf/MMbtu fired (17,023 scf/1000 lb steam)
  - Combustion air rate is 11,588 scf/MMBtu fired (15,671 scf/1000 lb steam
- 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 17,023 scf/1000 lb steam (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:
  17,023 x 1.3 = 22,129 scf/1000 lb steam
  Pressure drop through the system is then calculated as:

Burner	12.0 " WC
Boiler 8" WC x $(22{,}129/17{,}023)^2$ =	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:

1)GHG emission reductions achieved through technology, and

2)GHG emission reductions achieved through changes in activity efficiencies (in this case, "activity efficiency" refers to process improvements at a facility which result in a reduction in steam usage per unit of activity at the facility)

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

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 based on changes in activity efficiencies since the baseline period .

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 = 1,352 Btu/1000 lb steam

Direct emissions are then calculated as:

GHG_D = 117 lb-$CO_{2(e)}$/MMBtu x 1.352 MMBtu/1000 lb steam
= 158.2 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]:

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

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):

$$T = \frac{15{,}671 \text{ scf} \times 68^o + 17{,}023 \text{ scf} \times 30\% \times 380^o}{15{,}671 \text{ scf} + 17{,}023 \text{ scf} \times 30\%}$$

T = 145 ^oF or 605 ^oR

M = scf combustion air + flue gas x $\%_{FGR}$ (per 1000 lb steam)
M = (15,671 scf air/1000 lb steam + 17,023 scf flue gas/1000 lb steam x 30%) =20,778 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 = 2.65

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

= (2.65 x 0.7457)/87% = 2.27 kWh/1000 lb steam

GHG_I = GHG (electric motors)
= 0.524 lb-$CO_{2(e)}$/kWh x 2.27 kWh/1000 lb steam
= 1.19 lb $CO_{2(e)}$ per 1000 lb steam production

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

BEF = *158.2 + 1.2 = 159.4 lb-* CO_2(e)*/ton*

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

STEP 2. Technologically Feasible GHG Emission Control Measures

A. Analysis of Potential Control Measures

Use of Economizers

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 ^{o}F for firetube boilers and up to 250 ^{o}F for watertube boilers resulting in stack temperatures ranging from approximately 375 ^{o}F for a 75 psig firetube boiler up to 550 ^{o}F 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^{o}F are considered to be in condensing service 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. However, actual condensing operation does not occur until the flue gas is lowered below about 135^{o}F at which point the bulk condensation of moisture in the flue gas begins. For flue gas temperatures above about 200^{o}F (“standard” economizer), carbon steel construction is adequate. Economizer designs based on an approach of 20 ^{o}F or less (temperature differential between flue gas leaving the economizer section and the water entering the section) are achieved-in-practice for standard economizer designs while an approach of 50^{o}F is achieved in practice for condensing service economizers (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^{o}F 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^{o}F). 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^{o}F. However, it is important to recognize that the collection and return of hot condensate is an energy saving measure in itself which can offset the reduction in thermal efficiency for the boiler.

Based on the above discussion, it is apparent that specification of a BPS control measure based on a single required thermal efficiency to be achieved with an economizer is problematic since the theoretical potential thermal efficiency may vary significantly depending upon the return water temperature to the boiler. To address this issue, the District proposes to establish an economizer design-based 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 (efficiency) and when established at a maximum value 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.

Depending upon the design of the boiler, the configuration of the boiler feedwater system and the temperature and quantity of returned condensate, the combination of a substantial return of hot condensate in combination with a low steam saturation temperature may serve to limit the extent to which an economizer can be used to transfer heat from the boiler flue gas to the feedwater. Although lower pressure boilers often operate without deaerators (in particular, those with pressure less than 50 psig), the District's analysis of this reduction measure has included the conservative assumption that the boiler operation includes a pressure 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. Since the saturation temperature of steam for low pressure boilers may be as low as 240 ^oF (15 psig), further heating of the deaerated water in an economizer prior to delivery to the drum will not be feasible in some cases. In these cases, use of an economizer will be limited to heating the water supply to the deaerator which, for a tray-type deaerator, limits the water temperature to about 220^{o}F. The District's analysis indicates that if the combined water supply to the deaerator is greater than about 170^{o}F, heating the deaerator water supply to a reasonable extent in an economizer may result in outlet water temperature approaching 220^{o}F depending upon the pressure and basic efficiency of the boiler and upon the level of heat recovery achieved in the economizer. Based on this analysis, the District assumes that an economizer-based approach for efficiency improvement is not generally practical for boilers rated at less than 75 psig with water supply temperatures above 170^{o}F.

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

<u>Air Pre-heaters</u>

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.

Basic Boiler Efficiency

In cases where use of an economizer or other flue gas heat recovery system is not feasible or practical, direct GHG emissions become a function of the basic efficiency of the boiler itself. Determination of boiler efficiency presents numerous issues with respect to definition of efficiency and the method of determination. While an actual value of efficiency can be highly variable depending upon the selected definition of efficiency, reference states selected, and site specific factors, if the losses associated with boiler blowdown are ignored, energy loss from a boiler is primarily due to the heat content of the boiler flue gas which, at a given level of excess air in the combustion, is a direct function of the flue gas temperature at the stack. As mentioned previously, the lowest flue gas temperature achievable by any particular boiler is a function of the operating pressure of the boiler. The best currently available boiler designs (such as 4-pass firetube designs or high efficiency water tube designs achieve a flue gas temperature approach (flue gas temperature – steam saturation temperature) which does not exceed 100 ^{o}F at maximum firing rate. In the absence of a heat recovery system such as an economizer or air preheater, establishing a maximum stack temperature relative to the steam temperature at maximum firing condition provides a universal specification which can be applied to all boilers regardless of other site specific factors.

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 Item 1b can be considered feasible for inclusion as GHG reduction measures for this BPS. This measure may 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 2 would not be feasible as a general reduction measure since low pressure boilers often do not utilize a deaerator.

In addition, space limitations in existing facilities may make it impractical to install a blowdown drum and the associated piping. 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.

<u>Limiting Excess Air and Flue Gas Recirculation</u>

The combustion process in a boiler generally requires an excess of air (air in excess of the stochiometric 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 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.

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.

While limiting excess air and flue gas recirculation are achieved-in-practice GHG reduction measures for new boilers, existing boilers have fewer options available to meet emission limits on NOx; their options are primarily limited to burner technology since their stack temperatures may not be sufficiently high for operation of selective catalytic reduction systems. Burner options to meet NOx emission limits are generally either high FGR designs or designs which use high excess air in lieu of FGR for controlling flame temperature. Based on this, placing limits on excess air and flue gas recirculation rates is not considered to be a feasible GHG reduction measure for this category of boiler.

<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 savings in either the indirect GHG emissions due to the significant reduction in electric motor horsepower for motor-driven fans or in the 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 1
Technologically Feasible GHG Reduction Measures for *Gaseous Fuel-Fired Existing Boilers (Retrofit)*, *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. Equivalent heat recovery systems may utilize recovered heat for purposes other than steam generation provided such uses offset other fuel usage which would otherwise be required.	
Economizer System Criteria A. Except for boilers subject to the requirements of item B, 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, boiler feedwater temperature is defined as the temperature of the water stream delivered to the boiler from the deaerator or boiler 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*

B. For boilers with rated steam pressure less than 75 psig and a water supply temperature of 170°F or greater, the boiler shall be designed, in lieu of the requirements of item A above, to achieve a flue gas temperature no greater than the sum of the steam saturation temperature (°F at the steam drum operating pressure) plus 100°F.	*This level of performance represents current achieved-in-practice performance for boilers not equipped with a heat recovery system such as an economizer or air pre-heater*
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.	*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*
3. 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.	*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.

- Boiler section design which achieves a 100^{o}F approach between the flue gas and the steam saturation temperature is a current industry best practice and achieves boiler efficiencies in the range of 81-83% depending upon specifics, consistent with typical published guaranteed performance by boiler manufacturers.

- The use of high efficiency motors and variable frequency drives is a common specification in many industrial and commercial applications. A number of boiler operations in the SJV have been identified which have this feature.

- Use of automatic blowdown controls is 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 1 meet the following criteria:

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

All technologically feasible GHG reduction measures listed in Table 1 are based on technology (condensing economizers, high efficiency motors with variable speed drives) 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.

Therefore, all items listed above 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 130^{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 4.5% (same as Baseline). FGR is assumed to be 40% due to more stringent NOx emission limits relative to the Baseline.
- 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.

- The unit operates with a deaerator at 5 psig, resulting in a boiler feedwater temperature of 228 ^{o}F to the boiler.

- Application of the proposed BPS to this unit results in a requirement to install an economizer or equivalent heat recovery to achieve a stack temperature no greater than 20^{o}F above the boiler feedwater temperature. Therefore, the stack temperature would be 248 ^{o}F at the maximum firing rate.

- Based upon a boiler heat and mass balance for the given conditions (See Appendix E), the following quantities are applicable:
  - Net steam production is 769.3 lb/MMBtu fired or a Specific Fuel Consumption (SFC) of 1,000,000/774.1 = 1,300 Btu/lb steam
  - Flue gas rate is 12,587 scf/MMbtu fired (16,261 scf/1000 lb steam)
  - Combustion air rate is 11,588 scf/MMBtu fired (14,969 scf/1000 lb steam)
  - Boiler efficiency = 85.33%

- Per the Baseline, 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 17,023 scf/1000 lb steam (12 "WC for burner, 8 "WC for boiler).

- A GHG-controlled boiler exhibits lower flue gas flow per unit of steam but requires increased FGR to accommodate more restrictive NOx emission limits. In this case, the basic flue gas flow rate is 16,261 scf/1000 lb steam but an additional 40% must be added for the FGR operation. For an FGR rate of 40 %, flow through the boiler is estimated as:
  16,261 x 1.4 = 22,765 scf/MMBtu fired
  Pressure drop through the system is then calculated as:

Burner	12.0 " WC
Boiler 8" WC x $(22{,}765/17{,}023)^2$ =	<u>14.3</u>
Total	26.3

- 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 = 1,300 Btu/1000 lb steam (as stated in basis)

Direct emissions are then calculated as:

GHG_D = 117 lb-$CO_{2(e)}$/MMBtu x 1.300 MMBtu/1000 lb steam
= 152.1 lb/1000 lb steam

Indirect Emissions

Indirect emissions consist of emissions from operation of electric motors.

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]:

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

T = gas temperature, ^{o}R. Assuming constant heat capacity, gas temperature is based on the mix temperature of fresh combustion air (at 68 F) plus 30 % FGR (at 248 F):

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

$$T = \frac{14{,}969 \text{ scf} \times 68^{o} + 16{,}261 \text{ scf} \times 40\% \times 248^{o}}{14{,}969 \text{ scf} + 16{,}261 \text{ scf} \times 40\%}$$

T = 122 ^{o}F or 561 ^{o}R
M = scf combustion air + flue gas x $\%_{FGR}$ (per 1000 lb steam)
M = (14,969 scf air/1000 lb steam + 16,261 scf flue gas/1000 lb steam x 40%)
= 21,473 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 + 26.3 = 433.3 "WC

Substituting the given values into the equation:

Bhp-hr/1000 lb steam = 2.62

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

Combustion air fan specific energy consumption = (1-30%) x 2.62

= 1.83 Bhp-hr/1000 lb steam

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

= (1.83 x 0.7457)/95% = 1.44 kWh/1000 lb steam

GHG (electric motors) = 0.524 lb- $CO_{2(e)}$/kWh x 1.44 kWh/1000 lb steam
= 0.75 lb $CO_{2(e)}$ per 1000 lb steam production

GHG Emissions per Unit of Activity is then calculated as:

G_a = GHG_D + GHG_I = *152.1 + 0.8 = 152.9 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 = (159.4 – 152.9)/159.4= 4.1%

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 Gaseous Fuel-Fired Existing Boilers (Retrofit), Fired Exclusively on Natural Gas or LPG</u>

Boilers meeting this Best Performance Standard must comply with all three elements of this BPS (items 1, 2 and 3 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. Equivalent heat recovery systems may utilize recovered heat for purposes other than steam generation provided such uses offset other fuel usage which would otherwise be required.**

   <u>Economizer System Criteria</u>

   A. **Except for boilers subject to the requirements of item B 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, 2) 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 steam pressure rating less than 75 psig and a water supply temperature of 170°F or greater, the boiler shall be designed, in lieu of the requirements of item A above, to achieve a flue gas temperature no greater than the sum of the steam saturation temperature (°F at the steam drum operating pressure) plus 100°F.

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 a boiler blowdown rate exceeding 8 % of steam production, the boiler shall be equipped with an automatic boiler blowdown control system which will minimize boiler blowdown while controlling dissolved solids in the boiler water at an optimum level.

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

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

No other Achieved-in-Practice options were identified.

V. Appendices

Appendix A: Achieved-in-Practice Analysis
Appendix B: Public Notice of Intent
Appendix C: Comments Received after Initial Public Outreach
Appendix D: Public Comment Period Notification
Appendix E: Heat and Mass Balance Summaries

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]

[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

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
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:

Existing Boilers (Retrofit)

The District is soliciting public input on the following topics for the subject Class and Category of greenhouse gas emission source. The District needs your input in order to quantify "typical" greenhouse gas (GHG) emissions from Existing Boilers (Retrofit) that operated during the "baseline period" from the years 2002 - 2004, and currently have the lowest overall level of GHG emissions (achieved in practice).

Please supply any input and data regarding any existing boilers that:

1. Operated during the three year period from 2002 - 2004 (baseline), and
2. Other units that are currently operating at the lowest modern level of GHG emissions.

Information request for both categories include:

a. Actual overall thermal efficiencies (heat output vs. heat input),
b. Actual amount of electrical input (kilowatts or kilowatt hours) required,
c. List of the equipment utilized with the boilers (i.e. constant hp. electric motors, variable frequency drive motors, high efficiency motors, economizers of any kind, pre-heaters, etc.),
d. Proposals for a method to quantify the emissions per unit of activity, either in lbs of GHG produced per unit of heat output, or lbs of GHG per unit of steam produced, or other method, and
e. Suggestions for defining the classes and categories of source, (i.e. size range, industry etc.)

Information or any other comments regarding development of the proposed Best Performance Standard can be obtained from the District's website at http://www.valleyair.org/Programs/CCAP/CCAP_idx.htm. Written comments regarding the proposed Best Performance Standard should be addressed to Manuel Salinas by email, manuel.salinas@valleyair.org, or by mail at SJVUAPCD, 1990 E. Gettysburg Ave. Fresno, CA, 93726 and must be received by October 29, 2010. For additional information, please contact Manuel Salinas at manuel.salinas@valleyair.org or by phone at (559) 230-5800.

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 by clicking on http://www.valleyair.org/Programs/CCAP/CCAP_idx.htm.

Appendix C
Comment Received After Initial Public Outreach

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

Stakeholders Written Comments:

Constellation Wines US (CWU)
Kern Oil & Refining Company (KOR)
Manufacturers Council of the Central Valley (MCCV)
Nationwide Boiler Incorporated (NBI)
Sidel Systems USA Inc. (SSU)

1. **Comment:** During the development of CCAP I do not recall the District ever discussing the development of BPSs for existing equipment. It was my understanding that the intent of CCAP was to develop GHG mitigation for new projects for purposes of CEQA GHG mitigation, and not for the retrofitting of existing equipment to reduce GHG emissions. (KOR)

Response: If a boiler's throughput is increased, or fuel consumption is increased, or there is an increase in MMBtu/hr capacity, resulting in BACT being triggered, the project may be subject to a GHG significance determination (project GHG increase > 230 metric tons).

2. **Comment:** I received the notice concerning the development of a BPS for boiler retrofits. Would this apply to every retrofit, or only those where there is an increase in throughput? (MCCV, CWU)

Response: Modifications consisting of retrofitting a boiler solely for rule compliance purposes, may be exempt from BACT if specific conditions are met (Rule 2201, 4.3.2.). The project would then be considered as ministerial and CEQA requirements would NOT apply.

3. **Comment:** The BPS standards for new boilers are also applicable for older existing units. Our previous Central Valley CataStak SCR retrofit projects demonstrate you can meet the new proposed BPS criteria (including SCR's, 20F approach or condensing economizers, VFD's, low excess air operation, and <10% FGR) on existing or older boilers. (NBI)

Response: Comment is noted. The background information supplied is beneficial to the development of this BPS.

4. **Comment:** The Sidel SRU Flue Gas Condenser is designed to recover almost all of the waste energy from exhaust gases of non condensing boilers and appliances. This recovered energy can then be used in the companies process or washdown water, or be used for building space heating. By recovering the energy from the waste exhaust gases, the boilers efficiency can be increased to well over 90%.
The US DOE states that for every million BTU's recovered from these waste flue gases, and utilized back in facility, 118 lbs of CO2 will NOT be put into the atmosphere. The final benefit to recovering this energy from the flue gases is WATER being created when the flue gas temperature is cooled to below the dewpoint. This water can be added to the plant washdown water or be used as boiler makeup water, or it can even be used to irrigate the lawns and flower beds.

It does not matter if the boiler is new or existing, the goal should be to have it operating as efficiently as possible. Sometimes the installation is simple, sometimes it takes a major investment, and sometimes a method has to be created to best utilize this recovered energy. If the financial and environmental benefits are looked at to be long term, Best Performance only makes sense. (SSU)

Response: Comment is noted. The background information supplied is beneficial to the development of this BPS.

Appendix D
Public Comment Period Notification

Appendix E
Heat and Mass Balance Summaries

Case	**Existing Boiler Baseline**
Fired Duty MMBtu/hr	20.00
Absorbed Duty MMBtu/hr	16.40
Deaerator Temperature F	228
Steam Pressure psig	125
Return Water Temperature F	130
Stack Temperature F	380
Stack Heat Loss MMBtu/hr	3.5
Radiation/Convection Loss MMBtu/hr	0.1
Economizer Duty MMBtu/hr	0.37
LT Economizer Duty MMBtu/hr	0.00

	lb/hr	F	Btu/lb	MMBtu/hr
Gross Steam Rate	16,279	353	1193.7	19.43
Steam to DA	1,491	353	1193.7	1.78
Net Steam	14,788	353	1193.7	17.65
Feedwater to Boiler	17,582	228	196.3	3.45
Blowdown	1,129	353	196.3	0.22
Flash Steam to DA	173	228	1156.4	0.20
DA Steam Vent	83	228	1156.4	0.10
Return Water	16,001	130	97.97	1.57
Thermal Efficiency	82.02%			

Overall Steam Balance

		MMBtu/hr
Input		
	Absorbed Duty	16.40
	Return Water	1.57
	Total	**17.97**
Output		
	Net Steam	17.65
	DA Vent	0.10
	Blowdown	0.22
	Total	**17.97**

Steam	739.4	lb/MMBtu
Specific Fuel Consumption	1.352	MMBtu/1000 lb steam
Specific FG Rate	12,587.3	SCF/MMBtu
Specific Air Rate	11,587.5	SCF/MMBtu

DA Balance

Input		
	Return Water	1.57
	Flash Steam	0.20
	DA Steam	1.78
	Total	**3.55**
Output		
	DA Vent	0.10
	Boiler Feedwater	3.45
	Total	**3.55**

Fuel & Flue Gas Balance (enthalpies relative to flue gas and water vapor at 77 F)

		lb/hr	°F	Btu/lb	MMBtu/hr
Input					
	Natural Gas	874.52	77	22870	20
	Total Input				**20**
Output					
	Stack Gas	lb/hr	°F	Btu/lb	MMBtu/hr
	CO2	2,327.4	380	69	0.2
	N2	13,532.1	380	79	1.1
	O2	771.8	380	71	0.1
	H2O Vapor	1,860.0	380	1,191	2.2
	H2O Moisture	0.0	380	-741.47	0.0
	Total	18491.3			3.5
Absorbed Duty					16.40
Radiation/Convection					0.1
	Total Output				**20.00**

Case	**Existing Boiler BPS Case**
Fired Duty MMBtu/hr	20.00
Absorbed Duty MMBtu/hr	17.07
Deaerator Temperature F	228
Steam Pressure psig	125
Return Water Temperature F	130
Stack Temperature F	248
Stack Heat Loss MMBtu/hr	2.83
Radiation/Convection Loss MMBtu/hr	0.1
Economizer Duty MMBtu/hr	1.04
LT Economizer Duty MMBtu/hr	0.00

	lb/hr	F	Btu/lb	MMBtu/hr
Gross Steam Rate	16,938	353	1193.7	20.22
Steam to DA	1,551	353	1193.7	1.85
Net Steam	15,387	353	1193.7	18.37
Feedwater to Boiler	18,293	228	196.3	3.59
Blowdown	1,175	353	196.3	0.23
Flash Steam to DA	180	228	1156.4	0.21
DA Steam Vent	87	228	1156.4	0.10
Return Water	16,648	130	97.97	1.63
Thermal Efficiency	85.33%			

Overall Steam Balance

		MMBtu/hr
Input		
	Absorbed Duty	17.07
	Return Water	1.63
	Total	**18.70**
Output		
	Net Steam	18.37
	DA Vent	0.10
	Blowdown	0.23
	Total	**18.70**

Steam	769.3	lb/MMBtu
Specific Fuel Consumption	1.300	MMBtu/1000 lb steam
Specific FG Rate	12,587.3	SCF/MMBtu
Specific Air Rate	11,587.5	SCF/MMBtu

DA Balance

Input		
	Return Water	1.63
	Flash Steam	0.21
	DA Steam	1.85
	Total	**3.69**
Output		
	DA Vent	0.10
	Boiler Feedwater	3.59
	Total	**3.69**

Fuel & Flue Gas Balance (enthalpies relative to flue gas and water vapor at 77 F)

		lb/hr	°F	Btu/lb	MMBtu/hr
Input					
	Natural Gas	874.52	77	22870	20
	Total Input				**20**
Output					
	Stack Gas	lb/hr	°F	Btu/lb	MMBtu/hr
	CO_2	2,327.4	248	38	0.1
	N_2	13,532.1	248	45	0.6
	O_2	771.8	248	41	0.0
	H_2O Vapor	1,860.0	248	1,130	2.1
	H_2O Moisture	0.0	248	-878.54	0.0
	Total	18491.3			2.8
Absorbed Duty					17.07
Radiation/Convection					0.1
	Total Output				**20.00**