CLIMATE LEADERS GREENHOUSE GAS INVENTORY PROTOCOL OFFSET PROJECT METHODOLOGY

for

Project Type: Industrial Boiler Efficiency (Industrial Process Applications)

Climate Protection Partnerships Division/Climate Change Division
Office of Atmospheric Programs
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***Climate Leaders** is an EPA industry-government partnership that works with companies to develop comprehensive climate change strategies. Partner companies commit to reducing their impact on the global environment by setting aggressive greenhouse gas reduction goals and annually reporting their progress to EPA.*

Introduction

An important objective of the Climate Leaders program is to focus corporate attention on achieving cost-effective greenhouse gas (GHG) reductions within the boundary of the organization (i.e., internal projects and reductions). Partners may also use reductions and/or removals which occur outside their organizational boundary (i.e., external reductions or "offsets") to help them achieve their goals. To ensure that the GHG emission reductions from offsets are credible, Partners must ensure that the reductions meet four key accounting principles:

- ***Real:*** The quantified GHG reductions must represent actual emission reductions that have already occurred.
- ***Additional:*** The GHG reductions must be surplus to regulation and beyond what would have happened in the absence of the project or in a business-as-usual scenario based on a performance standard methodology.
- ***Permanent:*** The GHG reductions must be permanent or have guarantees to ensure that any losses are replaced in the future.
- ***Verifiable:*** The GHG reductions must result from projects whose performance can be readily and accurately quantified, monitored and verified.

This guidance provides a performance standard (accounting methodology) for greenhouse gas (GHG) offset projects that introduce more efficient (i.e., lower GHG emitting) boiler technology for industrial process applications.[1] The accounting methodology presented in this paper addresses the eligibility of industrial boiler efficiency projects as GHG offset projects and provides measurement and monitoring guidance. Program design issues (e.g., project lifetime, project start date) are not within the scope of this guidance and are addressed in the Climate Leaders offset program overview document: Using Offsets to Help Climate Leaders Achieve Their GHG Reduction Goals.[2]

Description of Project Type

Industrial boiler systems are used for heating with hot water or steam in industrial process applications. There are approximately 43,000 industrial boilers in the United States.[3] A majority of these (71%) are located at facilities in the food, paper, chemicals, refining, and

[1] There is no precise regulatory definition for an industrial boiler. An industrial boiler is typically defined by its common function – a boiler that provides heat in the form of hot water or steam for co-located industrial process applications. The industrial boiler category does not include utility boilers or commercial boilers as these do not provide the same service as industrial boilers and are separately defined in Federal regulations.
[2] Please visit http://www.epa.gov/climateleaders/resources/optional-module.html to download the overview document.
[3] Oak Ridge National Laboratory, Characterization of the U.S. Industrial Commercial Boiler Population, May 2005

primary metals industries. The major source of GHG emissions from a boiler system is carbon dioxide (CO_2) from the combustion of fossil fuels in the boiler. Other minor sources of GHGs can include methane (CH_4) from leaks in the natural gas distribution system and CH_4 and nitrous oxide (N_2O) as byproducts of combustion processes.

This section provides information on the general parameters that the proposed boiler project must match to use this performance standard.

Technology/Practice Introduced. This guidance document addresses the improved efficiency of industrial boilers used for heat for industrial process applications by adding advanced technologies (such as advanced heat recovery, controls and burners) to the boiler system. These technology-based efficiency improvements can be achieved when retrofitting or replacing an existing boiler with new technology, when purchasing a natural gas boiler to meet new demand, and/or when switching from a fuel oil, coal or electricity-based boiler to a natural gas boiler.

The performance standard is applicable to retrofits of existing industrial boilers using any market fuel (e.g., coal, diesel, fuel oil, natural gas, LPG/LNG) and new capacity or early replacement boilers using natural gas only. Retrofit projects are defined as those that add technological components to an existing boiler unit to improve overall efficiency. Projects that involve replacement of the boiler itself are considered new capacity or early replacement projects.

Projects improving the efficiency of an existing, electricity-fired boiler or introducing new boilers using coal, diesel, fuel oil or electricity cannot use the same standard. Also excluded are boilers fired or co-fired with by-product fuels generated by on-site processes (i.e., pulp liquor, wood chips, refinery gas, residual oil, coke oven gas, and blast furnace gas) and boilers that are used for electricity generation (i.e., utility boilers) or building space and water heating.

GHG emission reductions can also be achieved through energy efficiency improvements in the steam/hot water distribution system, the boiler auxiliaries, or in process efficiency improvements. This performance standard is not applicable for projects where these are the primary reason for undertaking the project, or for the decommissioning of boilers. Any secondary emission increases or decreases resulting from energy efficiency or process efficiency improvements of the boiler auxiliaries should be accounted for per guidance in the section on "Physical Boundary."

Project Size/Output. This performance standard may be used for industrial boilers of any size, including large boilers (often classified as water-tube and fire-tube boilers that have a capacity greater than 10 million Btu per hour (MMBtu/hour))[4] and are regulated by the Federal Clean Air Act (CAA) and smaller industrial boilers (less than 10 MMBtu/hour)

[4] Oak Ridge National Laboratory, Characterization of the U.S. Industrial Commercial Boiler Population, May 2005.

that are exempt from CAA regulations. As a practical matter, the technologies for boiler efficiency improvement are typically installed on larger water tube boilers greater than 10 MMBtu/hour since the fuel reductions are greater and better support project economics. However, smaller industrial boiler projects are also eligible to use this performance standard, provided they meet the specified performance threshold.

Project Boundary. This section provides guidance on which physical components and associated greenhouse gases must be included in the project boundary for an industrial boiler project.

Physical Boundary. The physical boundary of the project includes any component of the industrial boiler that will change between the baseline conditions and implementation of the project. In most cases, the physical boundary should be limited to the boiler unit which includes the boiler, burner, flue stack and economizer (see Figure 1) as the rated thermal efficiency of the boiler unit will depend on the interaction of these components.

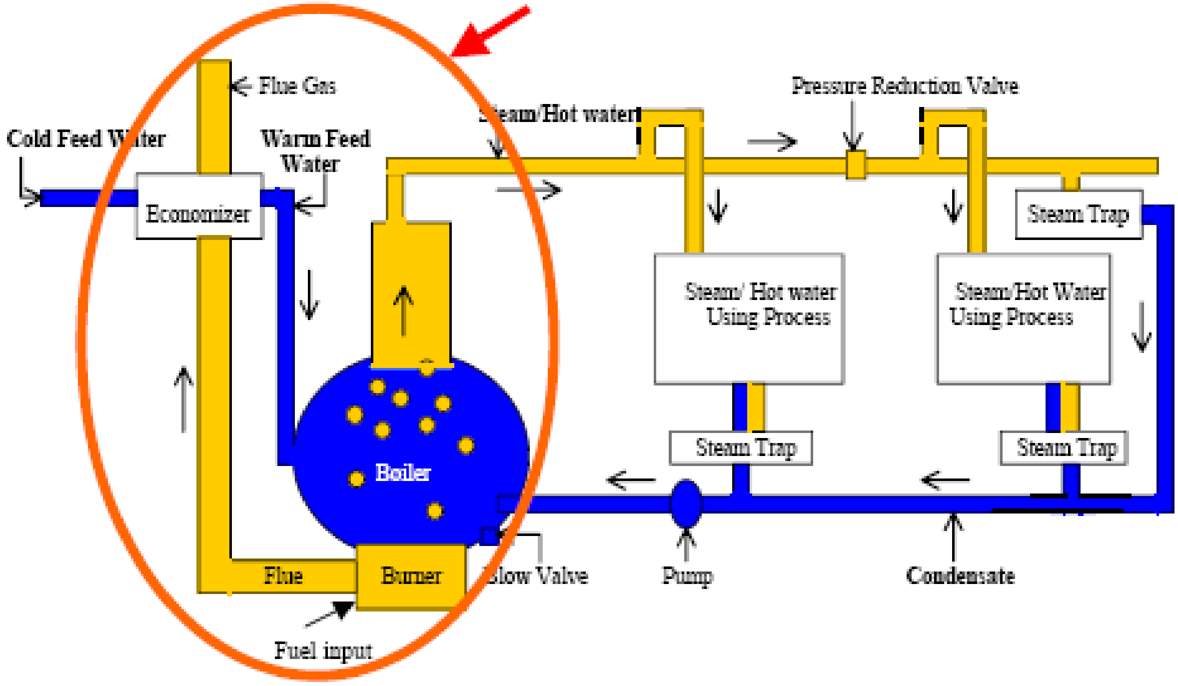
Upstream or downstream adjustments to the physical boundary must be made, however, to incorporate emissions changes in the following special cases:

- projects where the new boiler results in emissions changes in the steam distribution system;

- projects where the electricity use associated with the boiler auxiliaries (e.g., fans, pumps, conveyors) changes as a result of the new boiler. In this case, the equipment causing the changes in emissions from electricity should be included in the physical boundary, either as direct emissions or indirect emissions (if generated off-site); and,

- changes in CH_4 leakage from the natural gas distribution system, for example, from a switch from fuel oil to natural gas in the boiler. A small section of new natural gas distribution line from a nearby distribution main line will typically be installed and the leakage from this incremental section should be accounted for.

Figure 1. Physical Boundary for Industrial Boiler Projects



Greenhouse Gas Accounting Boundary. The GHG accounting boundary for an industrial boiler efficiency project includes primarily the CO_2 emissions from the combustion of fossil fuels. Other minor sources of GHGs may be CH_4 from leaks in the natural gas distribution system (generally small), and CH_4 and N_2O as byproducts of combustion. The GHG accounting boundary for industrial boiler projects should, therefore, include all CO_2, CH_4 and N_2O emissions. Appendix II, Table IId provides default emission factors for combustion-related CH_4 and N_2O. Appendix II, Table IIf provides default factors for CH_4 leaks from natural gas distribution.

Temporal Boundary. An annual accounting boundary should be used for industrial boiler projects. Emissions from an industrial boiler can fluctuate over the course of a year due to changing activity schedules and seasonal climate patterns. An annual accounting boundary will account for these fluctuations.

Leakage. Leakage is an increase in GHG emissions or decrease in sequestration caused by the project but not accounted for within the project boundary. The underlying concept is that a particular project can produce offsetting effects outside of the physical boundary that fully or partially negate the benefits of the project. Although there are other forms of leakage, for this performance standard, leakage is limited to activity shifting – the displacement of activities and their associated GHG emissions outside of the project boundary.

Potential sources of leakage from a boiler project could result from an increase in GHG emissions at another site, if the existing higher emitting boiler is retired early before the end of its useful life and used elsewhere in the facility, or resold for use in another application. If the old boiler is sold to replace another boiler at the end of its life instead of buying a more efficient boiler (defined as a boiler with a performance equal to, or better than, the performance threshold), the difference in GHG emissions between the replacement boiler and the performance threshold are considered leakage and must be quantified and subtracted from the emission reductions of the project.

If it is determined that significant emissions that are reasonably attributable to the project occur outside the project boundary, these emissions must be quantified and included in the calculation of reductions. No specific quantification methodology is required. All associated activities determined to contribute to leakage should be monitored.

Regulatory Eligibility

The performance standard subjects greenhouse gas offset projects to a regulatory "screen" to ensure that the emission reductions achieved would not have occurred in the absence of the project due to federal, state or local regulations. In order to be eligible as a GHG offset project, GHG emissions must be reduced below the level effectively required by any existing federal, state, or local policies, guidance, or regulations. This may also apply to consent decrees, other legal agreements, or federal and state programs that compensate voluntary action.

Federal Regulations. There are no federal standards that require any specific efficiency or GHG limitations at industrial boilers. The Federal Clean Air Act (CAA) includes emissions standards, however, for large industrial boilers (i.e., steam generating units with design heat input capacity of more than 10 MMBtu/hour for which construction, modification, or reconstruction commenced after June 9, 1989) which should be reviewed by the project developer as they influence the individual design characteristics of the boiler. The CAA regulations do not apply to units with less than 10 MMBtu/hour rated input capacity.

The following CAA Titles are pertinent to an industrial boiler and should be reviewed:

- **Title I, excluding Section 112: Attainment/Maintenance of National Ambient Air Quality Standards (NAAQS)** – An industrial boiler may be subject to the New Source Performance Standards (NSPS), which fall within this section and are codified in 40 CFR Part 60, subparts Db and Dc.[5] Under the NSPS, EPA regulates sulfur dioxide (SO_2), particulate matter (PM), and nitrogen oxide (NO_X) emissions from new boilers (steam generating units). Depending on the fuel type, throughput, and operational requirements of the boiler, NSPS may apply, and a control, such as a low-NOx burner, may be required. Applicable regulations are implemented by the state or local body and would be covered in the permit process.[6]
- **Title I, Section 112: Hazardous Air Pollutants (HAP)** – An industrial boiler may be subject to one or more National Emission Standards for Hazardous Air Pollutants (NESHAP), for example for mercury, organic, or total selected metals. NESHAP applies to all boiler units (existing and new) and fuel types (solid, gaseous, and liquid), although the requirements differ for each boiler category. Existing natural gas boilers have only a carbon monoxide (CO) limitation while new natural gas boilers have no limitations. New and existing coal (solid fuel) and oil (liquid fuel) units have several standards that must be met. In its final rule, codified in 40 CFR Part 63, EPA requires industrial boilers to meet HAP emission standards reflecting the application of the maximum achievable control technology (MACT).[7] The States are required to implement the Federal rule by evaluating each facility's compliance with MACT, which is a component of the State Title V CAA permit program for stationary sources. To comply with NESHAP, the purchaser of a new industrial boiler must receive a guarantee from the boiler manufacturer that the unit is in compliance. After the new unit is installed and operating, the facility must demonstrate compliance by a stack test. Compliance and reporting details would be covered in the Title V permit.
- **Title V: Operating Permits** – A large industrial boiler is a major source that would require a Title V permit. All applicable CAA regulations, including NSPS and NESHAP, would be covered by the permit process. Facilities with plans to install a new boiler or furnace for heat or process steam, or to update an existing boiler or furnace

[5] 40 CFR Part 60/63 FR 49442, Revision of Standards of Performance for Nitrogen Oxide Emissions From New Fossil-Fuel Fired Steam Generating Units, http://www.epa.gov/ttn/atw/combust/boiler/fr0998.txt
[6]40 CFR Part 60/70 FR 9705, Standards of Performance for Electric Utility Steam Generating Units for Which Construction Is Commenced After September 18, 1978; Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units; and Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units; Proposed Rule http://www.epa.gov/ttn/atw/combust/boiler/fr28fe05.html
[7] 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters.

(e.g., to increase capacity or improve performance) may be required to file an application for an air pollution construction permit with the State or local air board. Although there is an exemption for small boilers, large industrial boilers exceed the maximum heat input capacity exemption threshold.

To pass the regulatory screen, the project proponent must demonstrate that the proposed project is not being undertaken to come into compliance with any mandatory requirements contained in these federal programs. In circumstances where a proposed project is being undertaken to comply with regulations, but GHG emission reductions are achieved beyond what would reasonably be expected from technologies/practices used to meet the regulation, the project could pass the regulatory screen and the incremental GHG emission reductions may be considered as the project.

State and Local Regulations. States develop regulations to implement the Federal CAA requirements that the EPA delegates to the States. State air emission standards must be as stringent as the Federal CAA rules. States have the option to echo the federal code, to incorporate them by reference into state law, or states may establish regulations that are more stringent than the federal standards, as is often the case in California. Some states and local governments have additional efficiency standards, require periodic audits, or encourage the purchase of certain types of boilers. The project developer should review any such state and local standards.

GHG emission reductions resulting from compliance with any federal, state or local regulations are not eligible as GHG offsets.

Determining Additionality – Applying the Performance Threshold

This section describes the performance threshold (additionality determination) which an industrial boiler project must meet or exceed in order to be considered as a GHG project offset.

Additionality Determination. The additionality determination represents a level of performance that, with respect to emission reductions or removals, or technologies or practices, is significantly better than average compared with recently undertaken practices or activities in a relevant geographic area. Any project that meets or exceeds the performance threshold is considered "additional" or beyond that which would be expected under a "business-as-usual" scenario.

The type of performance threshold used for an industrial boiler project is a technology-based standard. The threshold represents a level of performance (technology) that is beyond that expected of a typical industrial boiler and is based on the suite of current technologies available for improving the efficiency of a boiler. The technology-based threshold was selected because the efficiencies of industrial boiler applications fall within a range that is dictated by operational and emission requirements making no single efficiency/emissions performance value applicable for a particular set of industrial boilers.

The performance threshold is defined as the fuel-specific boiler design that meets the engineer's specifications *with* a non-condensing economizer integrated into the system. This combination is already considered standard on industrial boilers and additional "options" would have to be added to the boiler system to achieve superior efficiency/CO_2 emissions performance. To generate reductions, a project developer would have to add at least one of the other technologies listed below to the boiler system in order to pass the performance threshold and make the project additional:

- Non-condensing economizer (conventional stack heat recovery)
- Condensing economizer (condensate heat recovery)
- Combustion air pre-heaters
- Blowdown waste heat recovery
- Turbulators

The engineer's specification to establish the new "nominal thermal efficiency" for the boiler should include the following performance information, and will depend on whether the boiler uses coal, fuel oil, or natural gas:

- Nominal output capacity
- Fuel
- Steam delivery pressure
- Steam delivery temperature
- NO_X limitations

An example of the process is presented in Table 1 where the technology threshold results in a thermal efficiency of 85% (nominal boiler (80%) with non-condensing economizer (+5%)). With the advanced burner and controls (+1%), condensing economizer (+1%), combustion pre-heater (+1%) and blowdown heat recovery (+1%) the efficiency is increased to 89%. Note that the condensing economizer replaces the non-condensing one with a marginal increase in efficiency of 1%.

Table 1. Industrial Boiler Efficiency and Emissions with Optional Components

Industrial Boiler and Optional Components	Efficiency Range and Incremental Improvement* (%)	Manufacturer Specified Efficiency Value* (%)	Resulting Overall Efficiency* (%)
Nominal Boiler Efficiency	75 – 83	80	80
Non-Condensing Economizer	1 – 7	5	85
Advanced Burner and Controls	1 – 2	1	86
Condensing Economizer	1 – 2	1	87
Combustion Pre-heater	1 – 2	1	88
Blowdown Heat Recovery	1	1	89

* Thermal Efficiency

Additional information on the derivation of the performance threshold and other efficiency improvement options can be found in Appendix I.

Quantifying Emission Reductions

Quantifying emission reductions from an industrial boiler project encompasses four steps: two are pre-project implementation (selecting the emissions baseline and estimating project emission reductions) and two are post-project implementation (monitoring and calculating actual project reductions).

Selecting and Setting an Emission Baseline: The emissions baseline for an industrial boiler project depends on whether the project involves the retrofit of an existing boiler or new construction. The emission baselines are presented below:

1. **Retrofit or Early Replacement.** For projects involving the retrofit of a coal, fuel oil or natural gas boiler or the early replacement of a coal or fuel oil boiler with natural gas, the baseline should be equal to the average annual emissions of the *existing boiler* (i.e., the boiler prior to retrofit) in KgCO_2 equivalent.

   In cases where a retrofit project also expands capacity, the portion of the project that is above the baseline fuel consumption should be treated as new capacity. In this case, the project developer must assume that the additional baseline fuel would have been natural gas.

2. **New Capacity.** For projects involving procurement of a natural gas boiler to meet new capacity, or the replacement of a boiler at the end of its lifetime with a new natural gas boiler, the thermal efficiency of the technology threshold (i.e.,

efficiency of the nominal boiler that meets the engineer's specifications *with* the non-condensing economizer) is used as the baseline. Boiler efficiency can be converted to project CO_2, CH_4 and N_2O emissions using the EPA emission factors referenced in Appendix II. The first step in converting to emissions involves determining the annual quantity of heat required for the specific process in MMBtu. This is the heat output requirement of the boiler, and is usually calculated through engineering analysis. CO_2 emissions can then be calculated by multiplying the annual heat output value by the CO_2 emission factor in Table IIa (Appendix II) that corresponds to the efficiency of the boiler system in place. In order to calculate CH_4 and N_2O emissions, the heat output value must first be converted to a heat input value. This is done by dividing the heat output value by the thermal efficiency of the boiler (i.e., required heat output / thermal efficiency = required heat input). Once this has been done, the project developer should use the appropriate emission factor in Table IId (Appendix II) to calculate CH_4 and N_2O emissions.

It is important to note that the performance threshold is based on thermal efficiency, and thus the direct CO_2, CH_4, and N_2O emissions from fuel combusted by the boiler. When developing the baseline for new construction, indirect emissions from electricity must be added to the direct emissions in order to estimate total CO_2 equivalent emissions.

In cases where special adjustments were made to the physical boundary, to address fuel, pipeline leakage and or electricity changes upstream or downstream from the boiler itself, the project developer must also include these in the baseline.

Estimating Project Emission Reductions. To estimate the potential GHG emission reductions from the offset project, the project proponent must compare emissions of the baseline with the emissions of the proposed project.

Estimating baseline emissions: Separate equations are presented for estimating baseline emissions from retrofit projects (Equations A,B,C) and new capacity (Equations D,E). Carbon content coefficients for natural gas, industrial coal and residual and distillate fuel oils are provided in Table IIc (Appendix II).

Retrofits

Equation A.

$$\textbf{Baseline } \mathbf{CO_2} \textbf{ emissions}_{\textbf{retrofits}} = (F_i * CC_i) + (EL * EF_{el})$$

Where:

i= fuel type

F_i= fuel consumption, MMBtu (use the average annual fuel consumption for the past three years)

EF_i= emission factor of fuel type i, kg CO_2/MMBtu

EL= quantity of electricity consumed, MWh (use the average annual consumption for the past three years)

EF_{el} = emission factor for electricity, kg CO_2/MWh. If the emissions intensity of the electricity being purchased is known (for example, through contacting the local power supplier), the corresponding emission factor should be used. Where the specific emissions profile of the purchased electricity is not known, the project developer should use the relevant regional electric power generation emission factors for the electricity component of their emissions

Equation B.

Baseline CH_4 and N_2O emissions $_{Retrofits}$= $(F_i * EF_{CH4}) + (F_i * EF_{N20}) + (EL * EF_{el, CH4}) + (EL * EF_{el, N2O})$

Where:

i= fuel type

F= fuel consumption, MMBtu (use the average annual fuel consumption from the boiler during the past three years)

$EF_{CH4,}$ $EF_{N20,}$ = fuel-related CH_4 and N_2O emission factors, respectively, kgCO_2e/MMBtu (see Appendix II, Table IId)

EL= quantity of electricity consumed, MWh (use the average annual consumption for the past three years)

$EF_{el,CH4,}$ $EF_{el, N20}$= Electricity-related CH_4 and N_2O emission factors, respectively, kgCO2e/MWh. If the emissions intensity of the electricity being purchased is known (for example, through contacting the local power supplier), the corresponding emission factor should be used. Where the specific emissions profile of the purchased electricity is not known, the applicant should use default values.

Equation C.

Total Baseline GHG Emissions $_{Retrofits}$ = Equation A + Equation B.

New Capacity

Total CO_2 equivalent emissions also must be calculated when estimating baseline emissions from new construction. Baseline CO_2 emissions for new construction are based on the technology-specific efficiency threshold for the project fuel type (Equation D). In order to derive CO_2 emissions from the efficiency threshold, it is necessary to first multiply the efficiency value of the boiler project by a carbon content coefficient for natural gas, and then by the carbon dioxide-to-carbon weight ratio (44/12). Because CO_2 emissions are calculated differently from non-CO_2 emissions, the calculation of CO_2 emissions is prepared first (Equation D) and CH_4 and N_2O emissions are provided separately in Equation E. The calculation for non-CO_2 emissions follows Equation B above, but uses estimates for project-level fuel and electricity consumption.

Equation D.

Baseline CO_2 Emissions $_{New\ Construction}$ = 1/PT * 14.47 * 44/12 * H_i

Where:

PT = performance threshold for the natural gas boiler (efficiency of the nominal boiler *with* condenser, as a percentage)

14.47 = carbon content coefficient of natural gas (kg C/MMBtu)

44/12 = conversion from C to CO_2

H_i = estimated annual heat output requirement for project, in MMBtu

Equation E.

Total Baseline GHG Emissions $_{New\ Construction}$ = Equation B + Equation D

Estimating project emissions: Project-related emissions are estimated using the same Equations above. Similar to the baseline calculations outlined above, the estimated annual fuel consumption of the project boilers is multiplied by the applicable CO_2, CH_4 and N_2O emission factors. Emissions from purchased electricity also are included to estimate total project-related CO_2 equivalent emissions.

Estimating project-related emission reductions: Emission reductions are estimated using Equation F.

Equation F.

Reductions $_{\textbf{project}}$ = **Emissions** $_{\textbf{baseline}}$ **– Emissions** $_{\textbf{project}}$

Monitoring

Four monitoring options are available for monitoring of emissions from boiler systems: (1) direct fuel volume measurement; (2) steam flow measurement; (3) direct stack CO_2 measurement; and (4) dealer certified fuel volume measurement.[8] The project developer should, taking into account their specific circumstances, select the most appropriate option.

The project developer should also take into account that monitoring options (1), (2), and (4) can be used to calculate CH_4 and N_2O emissions as well as CO_2. The default factors for CH_4 and N_20 can be applied as long as fuel volume or heating value (MMBtu) is known. Option (3) cannot normally be used to directly determine N_2O and CH_4 emissions as continuous emissions monitoring (CEM) equipment to measure these gases is not commercially available.

Direct Fuel Volume Measurement Approach. This method uses a volume meter positioned in the fuel line leading directly to the boiler to measure the volume of fuel burned in the boiler. At the end of each year, or some other designated period, the total volume of fuel burned is read from the meter and used in Equation G to estimate the emissions of CO_2 from the boiler over that period. For natural gas-fired boilers, the method also requires that temperature and pressure gauges be inserted in the fuel line to measure the temperature and pressure of the fuel gas. The average gas pressure and temperature over the measurement period is used in the equation to compensate for changes in gas density due to these two factors. Fuel oil is relatively incompressible and its density does not change appreciably over the year due to temperature and pressure fluctuations.

Equation G.

Actual $\mathbf{CO_2}$ **Emissions** $_{\textbf{monitored}}$ **= V x CF x (44/12) x CE x 520/T x P/14.7**

Where:

V = volume of fuel combusted (mscf/yr or mgal/yr)

CF = carbon factor (ton/mscf or ton/mgal)

44/12 = ratio of the weight of CO_2 to carbon

CE = combustion efficiency (assume 0.99)

520/T = ratio of standard temperature to temperature of fuel (oR)

[8] Clinton E. Burklin, Rick Lafleur, and Steve Erickson. "Measurement Methods for Commercial and Institutional Gas- and Oil-Fired Boilers," U.S. Environmental Protection Agency, December 30, 2004.

P/14.7 = ratio of fuel pressure to standard pressure (psia)

Steam Flow Measurement Approach. The steam flow measurement method uses the quantity of steam produced by the boiler and engineering data to calculate the CO_2 emissions from the boiler. This method is applicable to boilers fired with natural gas and fuel oil. In this method, the steam produced by the boiler is measured in the steam line just after it exits the boiler. At the end of a year, or some other designated period, the quantity of steam produced by the boiler is used to calculate the CO_2 emissions for the period using Equation H. In addition to the annual steam production, Equation H also requires the boiler owner to contact the boiler manufacturer to obtain the heat rate of the boiler, which is usually expressed in terms of million Btu of fuel required to produce a million Btu of steam. The heat rate is also called the overall thermal efficiency of the boiler.

Equation H.

$$\text{Actual } CO_2 \text{ Emissions}_{\text{monitored}} = Q \times HR \times 1/HV \times CF \times (44/12) \times CE$$

Where:

Q = quantity of steam produced (MMBtu/yr)

HR = heat rate of the boiler (MMBtu of fuel/MMBtu of steam)

HV = heating value of the fuel (MMBtu/mgal or MMBtu/mscf)

CF = carbon factor (ton/mscf or ton/mgal)

44/12 = ratio of the weight of CO_2 to carbon

CE = combustion efficiency (assume 0.99)

An orifice meter and an associated digital flow totalizer are used to provide a continuous digital display of the current steam flow rate and accumulated steam flow. These totalizers can be programmed to output values in any desired unit, which for this method should be million Btu of steam flow. The orifice meter is placed in the steam line as it exits the boiler. The orifice meter is factory calibrated, but should be re-calibrated annually. Temperature and pressure sensors are used by the totalizer to determine the quantity of heat conveyed by a unit of steam. These sensors are located in the steam line, adjacent to the orifice meter. The sensors are factory calibrated and do not require further calibration.

Direct Stack CO2 Measurement Approach. The direct stack CO_2 measurement methodology uses a set of three instruments to directly measure the CO_2 emissions from the boiler stack. A gas analyzer is used to measure the concentration of CO_2 in the boiler stack. A flow rate meter is used to measure the flow rate of the flue gases in the boiler stack. And a data integrator is used to integrate the CO_2 concentration and the flue gas flow rate over a given time period, such as a year, to calculate an annual CO_2 emission rate from the natural gas boiler.

Dealer Certified Fuel Volume Measurement Approach. An alternative to the direct fuel volume measurement method is to allow the use of dealer certified fuel volume measurements that are provided by the fuel dealer as part of their billing records. Although there is no national standard for the accuracy of retail fuel deliveries, all but one state (North Dakota) has adopted the guidelines set by the *National Conference on Weights and Measures (NCWM)*, known as *Handbook 44*.[9] Under this method, the boiler owner would not be required to install and maintain any fuel metering instrumentation. The natural gas retail dealers, however, would be required to maintain fuel delivery meters that meet the accuracy requirements of *Handbook 44* and provide documentation that reported sales volumes comply with these requirements. If there are multiple boilers, the retail fuel dealer must provide separate fuel use records for each boiler.

To estimate CO_2 emissions, the boiler owner would obtain a certified record of annual fuel use from the fuel retailer. The owner would use this fuel volume in *Equation* 1 (Section 6.1) to calculate the tons per year of CO_2 emissions. *Equation 1* requires natural gas boiler owners to obtain the temperature and pressure for which the certified natural gas volume has been adjusted from the fuel delivery company.

Calculating Actual Project Reductions. Quantifying project GHG emissions reductions occurs after the project has been implemented and monitored. To quantify project reductions, apply the equations presented in the section on estimating project emission reductions, using actual monitored project data rather than estimates, and adjust for any leakage (Equation I).

Equation I.

Reductions $_{project}$ = Emissions $_{baseline}$ – Emissions $_{monitored}$ (+/- leakage adjustments)

[9] The National Conference on Weights and Measures (NCWM) developed the "Specifications, Tolerances, and Other Technical Requirements for Weighting and Measuring Devices" in partnership with the Office of Weights and Measures of the National Institute of Standards and Technology (NIST). This set of guidelines is also known as Handbook 44. http://ts.nist.gov/ts/htdocs/230/235/h130 04/PDF/h130 04all.pdf

Appendix I. Development of the Performance Threshold – Data Set

The data sources used for developing these performance thresholds include the California Energy Commission's *Non Residential Market Share Tracking Study* published in April 2005, the U.S. Energy Information Administration's (EIA) *Manufacturing Energy Consumption Survey (MECS)* last updated in 2002, and Oak Ridge National Laboratory's (ORNL) *Characterization of the U.S. Industrial Commercial Boiler Population* published in May 2005. In addition, information on current engineering practices concerning industrial boilers were used, focusing on boilers installed in New York, Wisconsin, and California.

The service provided by the industrial boiler is heat to assist a specific industrial process. Each process has its own desired steam pressure and temperature requirements. This heat can, in theory, be obtained from the combustion of various types of fuel, or from electricity. Table 1a is based on the MECS 2002 survey and includes data on all market fuels and electricity used by industrial boilers, but excludes by-product fuels. The Table shows that in 2002 natural gas was the predominant fuel regardless of region or location, representing 78% of the total fuel consumed by industrial boilers. Coal made up another 15% and fuel oil about 6%.

Table Ia. End Uses of Fuel Consumption, 2002 (Trillion Btu.)

End Use	Net Demand for Electricity	Residual Fuel Oil	Distillate Fuel Oil and Diesel Fuel	Natural Gas	LPG and NGL	Coal (Excl. Coke and Breeze)	Total
TOTAL FUEL CONSUMPTION	**3,297**	**208**	**141**	**5,794**	**103**	**1,182**	**10,725**
Indirect Uses-Boiler Fuel	**23**	**127**	**35**	**2,162**	**8**	**776**	**3,131**
Conventional Boiler Use	11	76	25	1,306	8	255	1,681
(% of total fuel use)	0.65	4.52	1.49	77.69	0.48	15.17	N/A
CHP and/or Cogeneration Process	12	51	10	857	*	521	1,451
Direct Uses-Total Process	**2,624**	**60**	**43**	**2,986**	**64**	**381**	**6,158**
Process Heating	355	58	24	2,742	60	368	3,607
Process Cooling and Refrigeration	213	*	2	45	*	*	260
Machine Drive	1,746	2	16	109	4	5	1,882
Electro-Chemical Processes	295	N/A	N/A	N/A	N/A	N/A	295
Other Process Use	15	*	1	90	*	7	113
Direct Uses-Total Nonprocess	**551**	**4**	**50**	**513**	**24**	**19**	**1,161**
Facility HVAC (e)	280	3	5	417	5	5	715
Facility Lighting	212	N/A	N/A	N/A	N/A	N/A	212
Other Facility Support	51	*	1	30	*	*	82

Onsite Transportation	4	N/A	35	2	18	N/A	59
Conventional Electricity Generation	N/A	1	Q	55	*	14	70
Other Nonprocess Use	4	*	Q	10	*	0	14
End Use Not Reported	**112**	**17**	**12**	**132**	**6**	**6**	**285**
	Northeast Census Region						
Conventional Boiler Use	1	30	7	117	*	10	165
(% of total fuel use)	0.6	18.3	4.3	71.3	0.0	6.1	N/A
	Midwest Census Region						
Conventional Boiler Use	3	8	3	358	2	139	513
(% of total fuel use)	0.6	1.6	0.6	70.2	0.4	27.3	N/A
	South Census Region						
Conventional Boiler Use	6	33	13	660	3	97	812
(% of total fuel use)	0.7	4.1	1.6	81.9	0.4	12.0	N/A
	West Census Region						
Conventional Boiler Use	1	6	2	171	4	8	192
(% of total fuel use)	0.5	3.1	1.0	89.5	2.1	4.2	N/A

Notes: * = < 0.5%; Q = number is withheld because the relative standard error is > 50%.
Source: Energy Information Administration, 2002 Manufacturing Energy Consumption Survey.

Recent engineering practices in states such as California, Wisconsin, and New York indicate that use of natural gas is even more prevalent in industrial boilers that have been installed within the past 5 years. This is because industry has switched to natural gas in new boilers to meet the CAA and NESHAP regulations and the associated NOx, SO_2, and PM standards. For example, the CEC Non Residential Market Share Tracking Study shows that 100% of new industrial boiler applications installed in the years 2000-2002 used natural gas as the primary fuel, although they often had dual fuel burners to burn diesel in the event of a natural gas supply disruption.[10]

Certain industries (paper, refining, chemicals, primary metals) also use by-product fuels generated by on-site processes. For these industries, by-product use in boilers exceeds that of natural gas. The decision whether to use these by-products is based on different parameters than those for using a market fuel. The by-product fuels are typically required to be combusted, recycled or disposed in an environmentally approved manner and for

[10] California Energy Commission, Non Residential Market Share Tracking Study, CEC 400-2005-013, April 2005.

specific environmental or financial reasons. Their use in a boiler is, therefore, a separate decision than what market fuel to use.

Cogeneration applications can also provide process heat at the desired rates and quality. Because they also provide electricity, however, they offer an additional service that is not relevant for the industrial boilers addressed in this methodology.

There is no known data set describing the various efficiencies of industrial boilers in the United States. General engineering practices, however, indicate that industrial boilers are very similar in design efficiency and generate steam within a narrow range of efficiency. Differences in actual operating efficiency occur as a result of desired load, steam pressure, temperature requirements, and local emission thresholds which depend on site-specific parameters. Although there are no "standard" or "high" efficiency industrial boilers, there is a range of technology modifications, which can increase the operational thermal efficiency of the boiler's steam production process, once it is designed or after it is installed. Combinations of these modifications can increase boiler thermal efficiency to approximately 90%.

Using industry surveys and general engineering practices, a number of potential technology options for modifying and improving the efficiency of industrial boilers were identified. These options are described further in Table Ib. Among the technology options available for improving the efficiency of industrial boilers, non-condensing economizers and electronic ignitions are considered standard practices. The other options are not commonly used and could potentially be used for a GHG offset project. The list of technologies in Table Ib is not exhaustive and other emerging technologies are potentially eligible as well.

Table 1b. Function and Efficiency of Optional Industrial Boiler Components

Technology Option	Description	Manufacturer Specified Thermal Efficiency Value	Efficiency Range and Incremental Improvement	Common Practice
Non-condensing Economizer (Conventional stack heat recovery)	Recovers heat from the boiler exhaust and is used to pre-heat the boiler feed water. This reduces the load on the boiler as the temperature differential of the feed water in the boiler is reduced. [11,12,13]	5%	1-7%	Yes
Condensing Economizer (Condensate heat recovery)	Performs same function as the non-condensing economizer but it extracts more heat from the exhaust stream thereby providing for a higher inlet feed water temperature. By cooling the	1%[15]	1-2%	No

[11] U.S. Department of Energy Federal Energy Management Program. "Boiler Checklist" http://www.eere.energy.gov/femp/operations_maintenance/technologies/boilers/checklist.cfm Accessed January 26, 2007

[12] Interview – December 20, 2005: Aaron Sink, Engineering Support, Cleaver Brooks (402) 434-2017

[13] Nebraska Boiler "Boiler Efficiency Impact" http://www.neboiler.com/Economizer.asp. Accessed January 26, 2007

	exhaust air to the point of condensation, the latent heat of exhaust is captured. [14]			
Combustion Air Pre-heaters (Recuperators)	Preheats the incoming combustion air. This reduces the load on the boiler by reducing the energy needed to heat the air from ambient.	1%	1-2%,	No
Blowdown Waste Heat Recovery	Heat is recovered from boiler blowdown through a heat exchanger and a flash tank. Typically used to pre-heat boiler make-up water and the flash tank recovery can be used in the deaeration or other heating process.	1%[16]	1-2%.	No
Turbulators (Example of Advanced Burner)	Pieces of metal inserted in the tubes of fire-tube boilers, causing hot gases to travel more slowly and with more turbulence, resulting in better heat transfer to the water.	1%	1-2%	No
Oxygen Trim Controls (Example of Advanced Combustion Control)	These controls measure stack gas oxygen concentration and automatically adjust the inlet air at the burner for optimum efficiency.	1%	1%	No

The CEC 2003 Non-residential Market Share Tracking Study confirms the findings from Table Ib.[17] The purpose of the tracking study was to collect data on market shares, quantities, and prices of energy-efficient versus standard-efficiency technologies in California. Data collection involved 560 on-site surveys at manufacturing facilities and telephone interviews with 104 upstream market entities (manufacturers, distributors, dealers, installers, and designers). Table Ic shows that the boiler efficiency improvement options with the greatest overall penetration in the California market are electronic ignitions (31.1%) followed by conventional (non-condensing) stack heat recovery (22.2%). Both of these features are considered standard practice in new applications. The overall penetration of condensate heat recovery (20.9%) is higher than expected, but could be the result of special incentive programs during the 1980s and 1990s in California.

The second part of Table Ic shows common retrofit items in the three-year period from 2000-2002. The most common retrofits were system energy efficiency changes involving reduced steam pressure and improved insulation. Steam pressure and pipe insulation improvements are system changes outside of the defined project boundary for industrial boiler improvements. The next most common retrofits were electronic ignitions and non-condensing stack heat recovery. The rest of the boiler improvement options (condensate heat recovery, other heat recovery (e.g., blow down), O_2 trim control, advanced burners) were performed infrequently and back up the determination that these are not standard practices.

[14] U.S. Department of Energy, Energy Efficiency and Renewable Energy. "Improving Steam System Performance. http://www1.eere.energy.gov/industry/bestpractices/pdfs/steamsourcebook.pdf. Accessed January 26, 2007
[15] Alliant Energy. "HVAC Systems: Boilers" http://www.alliantenergy.com/docs/groups/public/documents/pub/p012392.hcsp#P19_1151. Accessed January 26, 2007.
[16] Energy. "HVAC Systems: Boilers" http://www.alliantenergy.com/docs/groups/public/documents/pub/p012392.hcsp#P19_1151. Accessed January 26, 2007.
[17] California Energy Commission, Non Residential Market Share Tracking Study, April 2005, CEC 400-2005-013

Table Ic. Industrial Gas Boiler Energy Efficiency Measures in California, 2003
SICs 21-34, 37-39

Measures on Existing Boilers	Percent (%)
Stack heat recovery	22.2
Condensate heat recovery	20.9
Other heat recovery	7.5
Automated tuning (O_2 trim control)	13.8
Electronic ignition	31.1
Turbulators for firetube boilers	9.9
Boiler and System Retrofits in Prior 3 Years (2000-2002)	
Stack heat recovery	10.7
Condensate heat recovery	3.0
Other heat recovery	0.0
Automated tuning (O_2 trim control)	1.9
Electronic ignition	11.8
Turbulators for firetube boilers	0.7
Increased pipe and jacket insulation (system EE)	22.1
Reduced boiler blow-down cycle (system EE)	3.6
Reduced steam pressure (system EE)	37.6
Variable speed drives on fans (system EE)	2.4
Automatic flue damper (system EE)	4.3
Smaller boiler for low load conditions (system EE)	0.7
Other	0.2

Source: California Energy Commission, Non Residential Market Share Tracking Study, CEC 400-2005-013, April 2005.
Note: EE = energy efficiency

Spatial Area. A national spatial area was used to develop the performance threshold for retrofit and new capacity industrial boiler efficiency projects. Engineering parameters for industrial boiler technology designs are constant and do not vary for geographic reasons. At least 12 states have developed appliance energy efficiency standards using American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) standards,[18] but in all reviewed cases, these do not impose any specific requirements on industrial boilers. Therefore, a performance threshold based on a technology standard is not expected to vary regionally for any mandatory reasons.

Voluntary initiatives such as rebates and tax credits do have an influence on the choice of equipment used. Utility rebate programs for high efficiency industrial boilers are available in California, Minnesota, Iowa, New York, and some New England States and can amount to 25% or more of the installed cost. These are voluntary programs, however, and any differences in technology implementation in these areas are not used as the basis for a more stringent threshold in these states.

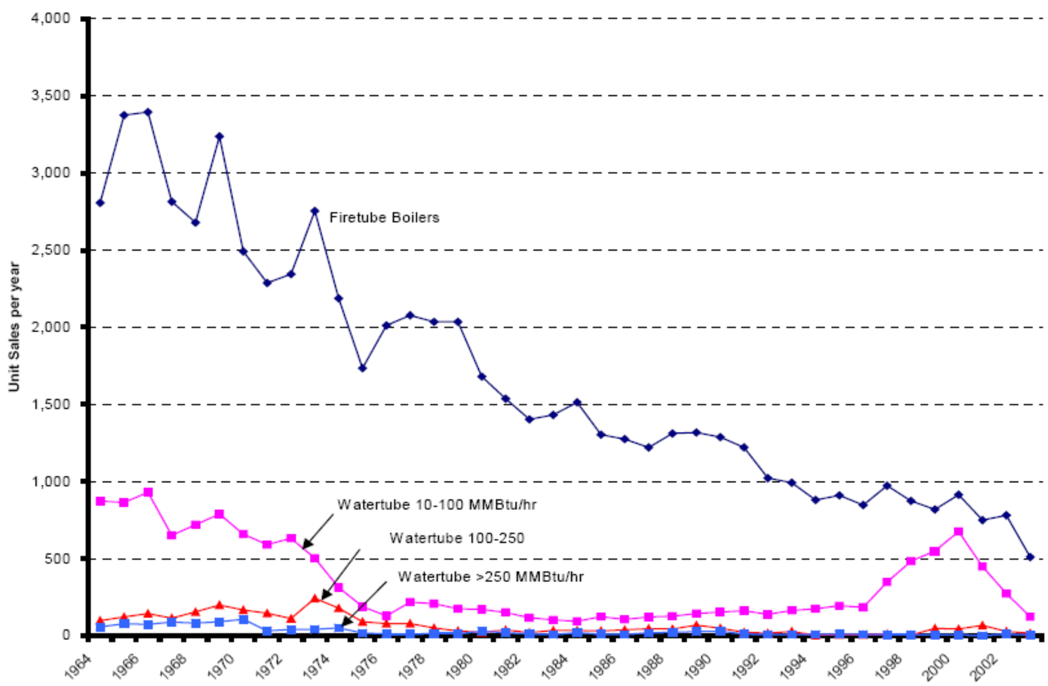
Temporal Range. The temporal range for the performance threshold is based on the CEC Non Residential Market Share Tracking Study, ORNL's Characterization of the U.S.

[18] http://www.ase.org/content/article/detail/2600

Industrial Commercial Boiler Population, and current engineering practices and trends concerning industrial boilers experienced in several states, including New York, Wisconsin, and California.

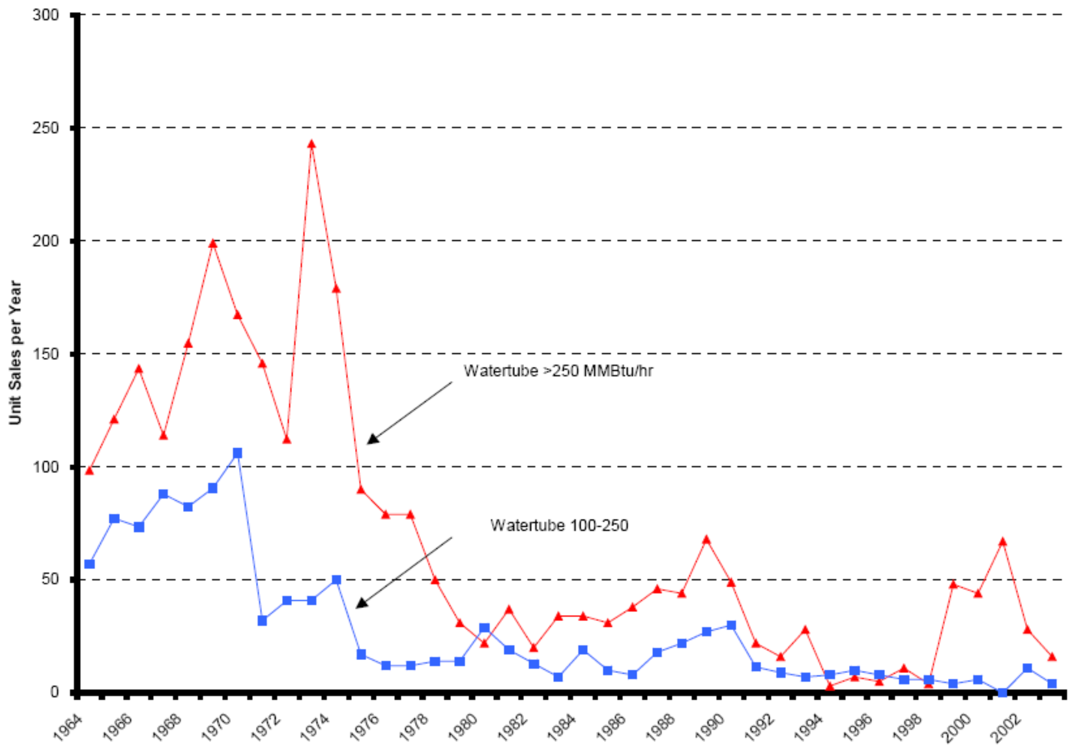
Figures 1a and 1b, which are based on the ORNL study, indicate that sales of industrial boilers have decreased between 1964 and 2003. This slowing rate of inventory turn-over could mean that a longer temporal range would be appropriate. Decisions related to efficiency improvements and fuel switching are, however, to a great extent, based on fuel prices and economics. Fuel costs began their sharp rise in late 1999 and surged higher again in 2005 thus providing the basis for more rapid payouts for energy efficiency projects and thus an increasing number of such activities. Moreover, the CEC Non Residential Market Share Tracking Study and engineering practices in New Jersey, New York and Wisconsin indicate that, recently, industry has mostly invested in natural gas-fired boilers rather than coal or fuel oil boilers. Therefore, a temporal range using current engineering practices (during the past 5 years) is appropriate.

Figure Ia. Sales of Boilers > 10 MMBtu/Hour 1964-2003



Source: Oak Ridge National Laboratory, Characterization of the U.S. Industrial Commercial Boiler Population, May 2005.

Figure Ib. Sales of Boilers ≥ 100 MMBtu/hour 1964-2003



Source: Oak Ridge National Laboratory, Characterization of the U.S. Industrial Commercial Boiler Population, May 2005.

Appendix II. Tables for Estimating and Calculating Emissions

Tables IIa – IIf provide default values that may be used by the project developer for estimating or calculating GHG emissions where project specific data are not available.

Table IIa. Relationship Between Boiler Thermal Efficiency and CO_2 Emissions

Boiler Thermal Efficiency	Emissions per Heat Output ($KgCO_2$/MMBtu)			
	Natural Gas	Distillate Fuel Oil	Residual Fuel Oil	Coal
80%	66.3	91.4	98.5	117.5
81%	65.5	90.3	97.3	116.0
82%	64.7	89.2	96.1	114.6
83%	63.9	88.1	94.9	113.2
84%	63.2	87.1	93.8	111.9
85%	62.4	86.1	92.7	110.6
86%	61.7	85.1	91.6	109.3
87%	61.0	84.1	90.6	108.0
88%	60.3	83.1	89.5	106.8
89%	59.6	82.2	88.5	105.6
90%	59.0	81.3	87.6	104.4
91%	58.3	80.4	86.6	103.3
92%	57.7	79.5	85.7	102.2
93%	57.1	78.7	84.7	101.1
94%	56.4	77.8	83.8	100.0

Note: The efficiencies were converted to emissions based on the EPA carbon content coefficients provided in Table IIc.

Table IIb. CO_2 Emission Factors for Various Fuels

Fuel Type	kg CO_2/MMBtu
Natural Gas	53.06
Distillate Fuel Oil	73.15
Residual Fuel Oil	78.80
Coal	93.98

Note: Industrial coal value based on Year 2006 “Industrial Other Coal” value.
Source: Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2006, April 2008. U.S. Environmental Protection Agency.

Table IIc. Default CH_4 and N_2O Emission Factors for Natural Gas, and Fuel Oil, Coal

Fuel Type	Greenhouse Gas	Emissions per Unit of Fuel Input (kg CO_2e/MMBtu)
Natural Gas	CH_4	0.105
	N_2O	0.031
Petroleum (Commercial sector)	CH_4	0.231
	N_2O	0.186
Petroleum (Industrial sector)	CH_4	0.063
	N_2O	0.186
Coal	CH_4	0.231
	N_2O	0.496

Source: Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2006. U.S. Environmental Protection Agency, April 2008.

Table IId. Default CH_4 and N_2O Emission Factors for Electricity

Fuel Type	Greenhouse Gas	Emissions per Unit of Fuel Input (kg CO_2e/MMbtu)
Natural Gas	CH_4	0.021
	N_2O	0.031
Petroleum	CH_4	0.063
	N_2O	0.031
Coal	CH_4	0.021
	N_2O	0.496

Note: Electricity emissions of CH_4 and N_2O relate to the fuel used to produce the electricity. Information on fuel type will be needed to estimate CH_4 and N_2O.
Source: Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2006. U.S. Environmental Protection Agency, April 2008.

Table IIe. Emission Factors for Electricity Use by Project Equipment by eGRID Subregion (2004)

eGRID Subregion	States included in eGRID Subregion	NERC Region	Emission factor for electricity used by project equipment (kg CO2/kWh)
AKGD* (Alaska Grid)	AK	ASCC	0.604
AKMS (Alaska Miscellaneous)	AK	ASCC	0.630
AZNM (WECC- Southwest)	AZ, CA, NM, NV, TX	WECC	0.634
CAMX (WECC- California)	CA, NV, UT	WECC	0.572
ERCT (Texas)	TX	ERCOT	0.600

FRCC (Florida)	FL	FRCC	0.612
HIMS (Hawaii- Miscellaneous)	HI	HICC	0.738
HIOA* (Hawaii- Oahu)	HI	HICC	0.783
MORE (Midwest- East)	MI, WI	MRO	1.005
MROW (Midwest- West)	IA, IL, MI, MN, MT, ND, NE, SD, WI, WY	MRO	1.050
NEWE (New England)	CT, MA, ME, NH, NY, RI, VT	NPCC	0.641
NWPP (WECC- Northwest)	CA, CO, ID, MT, NV, OR, UT, WA, WY	WECC	0.770
NYCW (New York- NYC, Westchester)	NY	NPCC	0.788
NYLI (New York- Long Island)	NY	NPCC	0.686
NYUP (New York- Upstate)	NJ, NY, PA	NPCC	0.821
RFCE (RFC- East)	DC, DE, MD, NJ, PA, VA	RFC	0.800
RFCM (RFC- Michigan)	MI	RFC	0.880
RFCW (RFC- West)	IL, IN, KY, MD, MI, OH, PA, TN, VA, WI, WV	RFC	0.951
RMPA (WECC- Rocky Mountains)	AZ, CO, NE, NM, SD, UT, WY	WECC	0.778
SPNO (SPP- North)	KS, MO	SPP	1.007
SPSO (SPP- South)	AR, KS, LA, MO, NM, OK, TX	SPP	0.699
SRMV (SERC- Mississippi Valley)	AR, LA, MO, MS, TX	SERC	0.634
SRMW (SERC- Midwest)	IA, IL, MO, OK	SERC	0.979
SRSO (SERC- South)	AL, FL, GA, MS	SERC	0.847
SRTV (SERC- Tennessee Valley)	AL, GA, KY, MS, NC, TN	SERC	0.941
SRVC (SERC- Virginia/Carolina)	GA, NC, SC, VA, WV	SERC	0.890

Note: The emission factors in Table II.e reflect variations in electricity use by project equipment across regions and load type (i.e., base versus non-baseload). Coincident peak demand factors from a 2007 ACEEE study were combined with EPA's eGRID emission factors for baseload and non-baseload power to derive the emission factors presented in this table.[19,20]

Table IIf. Default Fugitive CH_4 Emission Factors for Natural Gas Distribution Systems

Pipeline Leaks		2004
Distribution Mains - Cast Iron	Mscf/mile-yr	238.70
Distribution Mains - Unprotected steel	Mscf/mile-yr	110.19
Distribution Mains - Protected steel	Mscf/mile-yr	3.07
Distribution Mains - Plastic	Mscf/mile-yr	9.91
Services- Unprotected Steel	Mscf/service	1.70
Services- Protected Steel	Mscf/service	0.18

[19] York, D. Kushler, M. Witte, P. "Examining the Peak Demand Impacts of Energy Efficiency: A Review of Program Experience and Industry Practice." American Council for and Energy-Efficient Economy (ACEEE). February 2007. http://www.aceee.org/pubs/u071.htm.
[20] The Emissions & Generation Resource Integrated Database (eGRID) is a comprehensive inventory of environmental attributes of electric power systems, available at http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

Services- Plastic	Mscf/service	0.01
Services- Copper	Mscf/service	0.25

Source: U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2006, April 2008.

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