|  |
| --- |
| process heat  Steam Boiler Economizer, industrial  SWPR007-01 |

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Measure Name

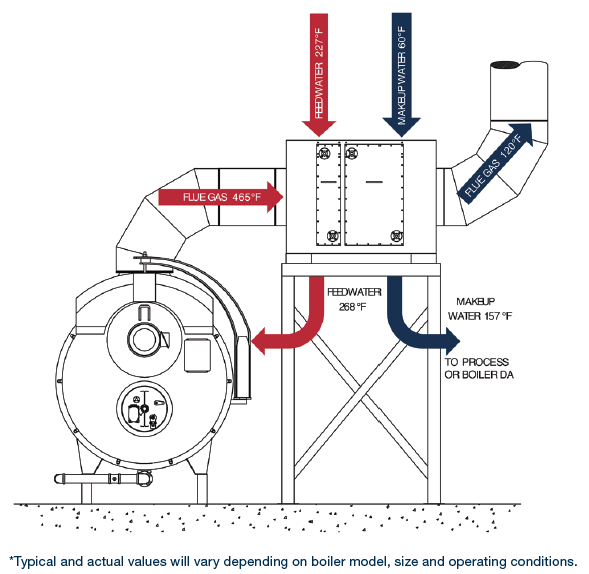
Steam Boiler Economizer, Industrial

Statewide Measure ID

SWPR007-01

Technology Summary

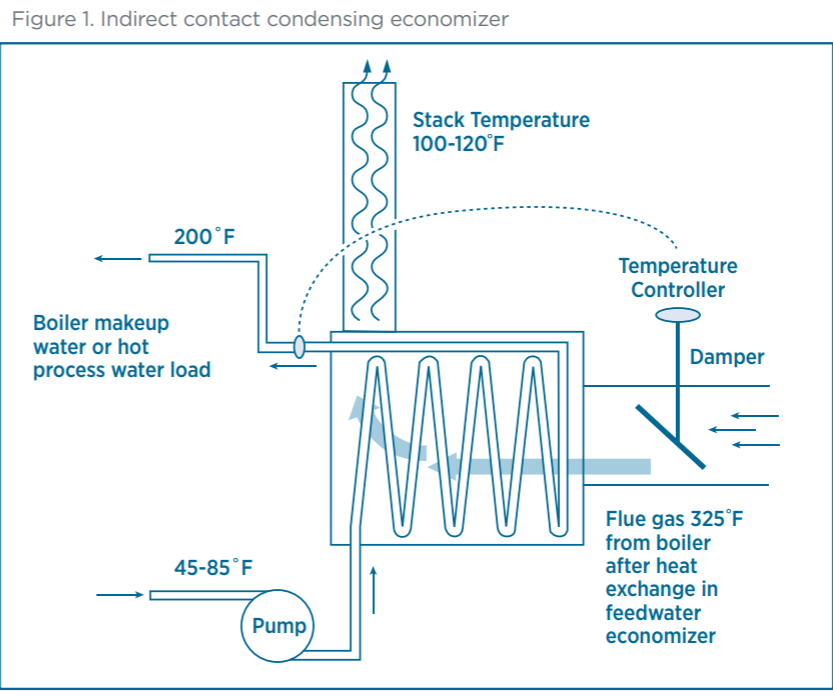
Installing a flue gas heat recovery system can make a steam boiler more efficient by capturing and re-using heat energy that would otherwise have escaped out of the flue or chimney. A boiler economizer reduces the boiler fuel requirements by transferring heat from the flue gas to incoming make-up water. Boiler flue gases are often rejected through the stack at temperatures of greater than 400 °F. Generally, boiler efficiency can be increased by recovering waste heat, and often reduces fuel requirements by 5% to 10%. Other technical advantages are the reduction of greenhouse gas emissions (CO2 & NOx) and rapid return on investment.



Two-Stage Heat Recovery System*[[1]](#footnote-1)*

A typical economizer will have a series of finned tubes contained within and arranged to maximize energy transfer between the cold process fluid and the flue gas. While conventional economizers can significantly reduce the flue gas temperature of a heating unit, this temperature is still significantly above the dew point of the water in the flue gas (a combustion product). A decrease of flue gas temperature across a single-stage economizer of 40 °F results in an increase of boiler efficiency of approximately 1%, according to the U.S. Department of Energy (DOE).[[2]](#footnote-2) By recovering waste heat, an economizer can often reduce fuel requirements by 5% to 10%. A dual stage unit increases recoverable waste heat over a single stage unit by cooling the flue gas below its dew point, recovering both sensible and latent heat from the flue gas and flue gas water vapor, respectively.

The minimum flue gas exit temperature for a *non-condensing economizer* is approximately 300°F to prevent condensation (standard noncondensing economizers are not designed to withstand the carbonic acid in condensed water vapor), as shown in the brown arrows in the figure above. According to the U.S. DOE, “An *indirect contact* condensing economizer … removes heat from hot flue gases by passing them through one or more shell-and-tube or tubular heat exchangers. This economizer can heat fluids to a temperature of 200 °F while achieving exit gas temperatures as low as 75 °F.” [[3]](#footnote-3)



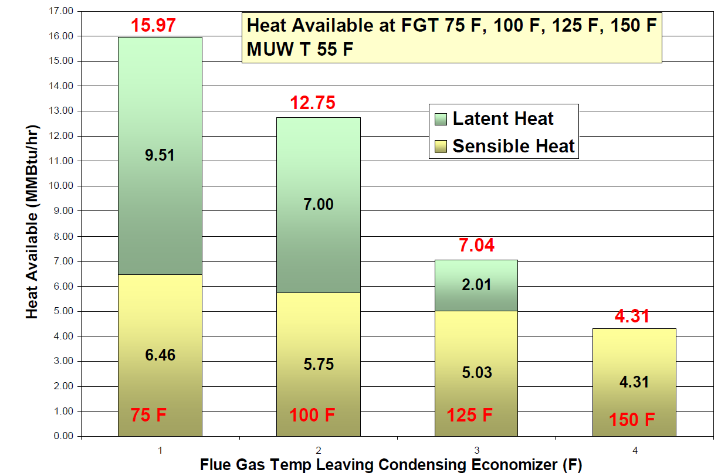
Like a conventional economizer, the *condensing economizer* will reduce steam boiler fuel requirements by transferring heat from the flue gas to the boiler feedwater. However, this unit improves potential waste heat recovery, as it can cool the flue gas below the water vapor dew point and condense it – recovering both sensible heat and latent heat from the water in the flue gas (The dew point is the temperature at which the water vapor in the flue gas begins to condense in a constant pressure process). This type of unit is generally limited to processes that have large make‐up water or cold process fluid flow rates due to the amount of heat that must be absorbed by the liquid to condense water (as shown in the blue arrows in the figure above). A condensing economizer can increase overall heat recovery and steam system efficiency by up to 10% by reducing the flue gas temperature below its water vapor dew point temp., resulting in improved effectiveness of waste heat recovery (Water vapor content in the natural-gas combustion product is about 11% by weight). However, the liquid water (or condensate) produced by this process is acidic and must be neutralized to the local code requirement for safely and sanitary drain disposal.

The savings potential is based on the existing stack temperature, the volume of make-up or hot water needed, and the hours of operation. According to a U.S. DOE and Enbridge Gas Distribution Inc. presentation on boiler economizer heat recovery, “The economizer reclaims both sensible heat from the flue gas and latent heat by condensing flue gas water vapor ...”[[4]](#footnote-4)

Boiler Efficiency of Condensing Economizers[[5]](#footnote-5)

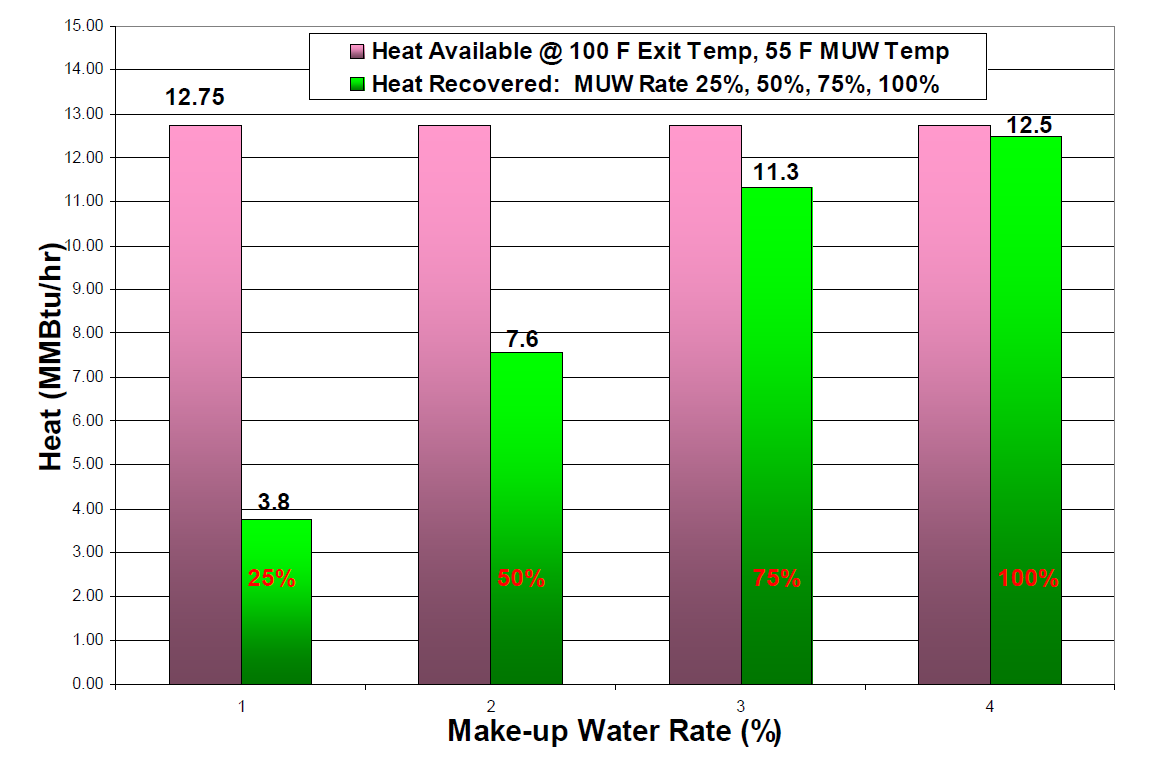
|  |  |  |
| --- | --- | --- |
| **System** | **Combustion Efficiency  @ 4% Excess O2 (%)** | **Stack Gas  Temperature (°F)** |
| Boiler | 78 to 83% | 350 to 550 °F |
| * With Feedwater (FW) Economizer | 84 to 86% | 250 to 300 °F |
| * With FW and Condensing Economizer | 92 to 95% | 75 – 150 °F |

The total heat recovered by the make-up water also depends on its flow rate (gpm or lb/hr) and the conditions of the flue gas leaving the economizer, as presented by Aqeel Zaidi, P.Eng., of Enbridge Gas Distribution Inc.[[6]](#footnote-6) The figure below shows the available heat in the stack at different exhaust temperatures, as presented by the steam plant conditions in the DOE Steam Tip Sheet#26A example.



Energy Available from a 100,000 lb/hr Natural Gas-Fired Steam Boiler (MMBtu/hr[[7]](#footnote-7)

The figure below defines the ratio of the actual heat transfer rate from the hot exhaust flue stack to the cold makeup water, based on the later flow rate percentage, as stated in the DOE example.



Recovery Heat Depends on Heat Sink Size[[8]](#footnote-8)

Measure Case Description

The measure case is defined as a process boiler that is retrofit with either a feedwater or condensing economizer.

Measure Offerings

|  |  |
| --- | --- |
| **Statewide Measure Offering ID** | **Measure Offering Description** |
| A | Process Boilers, Feedwater Economizer, 81.4% TE |
| B | Process Boilers, Condensing Economizer, 87.2% TE |

Base Case Description

The base case is defined as a gas-fired steam boiler that operates with no flue stack heat recovery system.

Code Requirements

The minimum efficiency of a process steam boiler is stipulated in the California Appliance Efficiency Regulations (Title 20) and the Building Energy Efficiency Standards (Title 24).[[9]](#footnote-9)

Applicable State and Federal Codes and Standards

|  |  |  |
| --- | --- | --- |
| **Code** | **Applicable Code Reference** | **Effective Date** |
| CA Appliance Efficiency Regulations – Title 20 (2019) | 1605.1 | n/a |
| CA Building Energy Efficiency Standards – Title 24 (2019) | 110.2 | n/a |
| Federal Standards | None. | n/a |

Normalizing Unit

None

Program Requirements

Measure Implementation Eligibility

All combinations of measure application type, delivery type, and sector that are established for this measure are specified below. Measure application type is a categorization based on the circumstances and timing of the measure installation; each measure application type is distinguished by its baseline determination, cost basis, eligibility, and documentation requirements.  Delivery type is the broad categorization of the delivery channel through which the market intervention strategy (financial incentives or other services) is targeted. This table also designates the broad market sector(s) that are applicable for this measure.

*Note that some of the implementation combinations below may not be allowed for some measure offerings by all program administrators.*

Implementation Eligibility

|  |  |  |
| --- | --- | --- |
| **Measure Application Type** | **Delivery Type** | **Sector** |
| Add-on equipment | DnDeemed | Com |
| Add-on equipment | DnDeemed | Ind |
| Add-on equipment | DnDeemed | Ag |
| New Construction | DnDeemed | Com |
| New Construction | DnDeemed | Ind |
| New Construction | DnDeemed | Ag |

Eligible Products

This measure is applicable to steam boilers only.

The steam boiler must have an input rating ≤ 20 million Btu/hr.

The boiler manufacturer, model, and spec sheet should be submitted for verification.

For a dual-stage economizer:

The disposal of combustion condensate must meet local codes regarding sanitary drain or storm sewer.

Some applications may require a neutralizer for the acidic combustion condensate.

There are no boiler efficiency eligibility requirements for the measure, for both single stage and two stage economizers. The efficiency gains were averaged from past custom projects and meeting these efficiencies (estimated improvement at 2% and 8% for single and dual stage economizer, respectively) is not a requirement for rebate.

Eligible Building Types and Vintages

This measure is applicable for any existing or new commercial, industrial, or agricultural building.

The evaluation of this measure showed that the following conditions provide good candidates for an economizer retrofit:

Steam boilers that exceed 100 boiler horsepower (> 3.3 Million Btu/hr)

Steam boiler exiting stack temperature at greater than 400 °F

Operating at steam pressures of 75 psig or above

Boiler load factor of at least 40%

Average temperature of the exiting flue stack from the economizer must be below 200 °F to cause water vapor condensation in dual-stage economizer

Minimum 50% make-up water for dual-stage economizer

This measure is most applicable for the industrial facilities (NAICS code 31-33) but could also be applicable for agricultural (NAICS Code 11), oil and gas extraction (NAICS Code 21) and dry cleaning/laundry services (NAICS Code 8123). Among the best candidates for heat recovery systems are the following industries:

Textile, commercial laundries

Food and beverage

Breweries

Pulp and paper mills

Chemical manufacturing

Petroleum refining industries

District heating

Large hospitals

Greenhouses

Eligible Climate Zones

This measure is applicable in any California climate zone.

Program Exclusions

Hot water boilers are not eligible.

Data Collection Requirements

Data collection requirements are to be determined.

Use Category

Process heat

Electric Savings (kWh)

Not applicable.

Peak Electric Demand Reduction (kW)

Not applicable.

Gas Savings (Therms)

The unit energy savings (UES) of a boiler flue stack economizer were calculated as the difference between the baseline and measure case unit energy consumption (UEC). The baseline UEC of a process boiler that meets the minimum code combustion efficiency was calculated as a function of the process boiler capacity factor, annual operating hours, and boiler combustion efficiency (CE). The UEC of a measure case boiler was based upon the baseline UEC, adjusted by the ratio of the CE of a baseline boiler and a measure case boiler. These calculations, the inputs, and explanation of derivation of inputs are provided below.

*UES= Unit energy savings, therms/kBtu/hr input rating*

*UECbase = Unit energy consumption, base case, therms/kBtu/hr input rating*

*UECmeasure = Unit energy consumption, measure case, therms/kBtu/hr input rating*

*UEC = Annual unit energy consumption, baseline or measure case*

*CF = Average Load Capacity Factor (kBtu/hr out/kBtu/hr rated)*

*HOURS = Annual hours of operation (hrs/year)*

*CE = Process boiler combustion efficiency, baseline or measure case (%)*

Inputs and Assumptions

UEC Calculation Inputs – Baseline Process Boiler

| **Input** | **Baseline Value** | **Source** |
| --- | --- | --- |
| Average Load Capacity Factor  (kBtu/hr out/kBtu/hr rated) | 0.40 | Itron and ERS. 2019. *2017 Small/Medium Commercial Sector ESPI Impact Evaluation Draft Report.* Prepared for the California Public Utilities Commission. March 1. Page 5-21, Table 5-22. |
| Operating Hours (hrs/year) | 7,640 | Itron and ERS. 2019. *2017 Small/Medium Commercial Sector ESPI Impact Evaluation Draft Report.* Prepared for the California Public Utilities Commission. March 1. Page 5-20, Table 5-19. |
| Steam Boiler Thermal Efficiency (TE) | 79% | California Energy Commission (CEC). 2018. 2019 Building Energy Efficiency Standards for Residential and Nonresidential Buildings (Title 24). CEC-400-2018-020-CMF. Table 110.2-K.  California Energy Commission (CEC). 2019. California Code of Regulations Title 20 Public Utilities and Energy. CEC-140-2019-002. Table E-4. |
| Conversion factor (therms/kBtu) | 0.01 | - |

UEC Calculation Inputs – Measure Case Process Boiler

| **Input** | **Measure Case Value** | **Source** |
| --- | --- | --- |
| Average Load Capacity Factor (kBtu/hr out/kBtu/hr rated) | 0.40 | Itron and ERS. 2019. *2017 Small/Medium Commercial Sector ESPI Impact Evaluation Draft Report.* Prepared for the California Public Utilities Commission. March 1. Page 5-21, Table 5-22. |
| Annual Operating Hours (hrs/year) | 7,640 | Itron and ERS. 2019. *2017 Small/Medium Commercial Sector ESPI Impact Evaluation Draft Report.* Prepared for the California Public Utilities Commission. March 1. Page 5-20, Table 5-19. |
| Steam Boiler Thermal Efficiency (TE) – Tier 1: Feedwater (Single-Stage) Economizer | 81.4% | Southern California Gas Company (SCG). 2019. “SWPR007-01 Calculations for Single and Dual Stage Economizers.xlsx.” |
| Steam Boiler Thermal Efficiency (TE) – Tier 2: Condensing (Dual-Stage) Economizer | 87.2% |
| Conversion factor (therms/kBtu) | .01 | - |

**Average Load Capacity Factor.** Boiler load capacity factor is the ratio of actual energy consumption during a certain period to the energy consumption that would have occurred if the boiler were to operate at full capacity during the same period. The average capacity factor for this analysis was adopted from the *2017 Small/Medium Commercial Sector ESPI Impact Evaluation Draft Report* (“2017 ESPI Impact Evaluation”) prepared by Itron and ERS.[[10]](#footnote-10) This ex post evaluation study estimated the capacity factor for seven of eight sites in the PG&E service area that were included in the evaluation sample.

The capacity factor determined by the 2017 ESPI Impact Evaluation is slightly lower from than the average capacity factor across different industries derived from previous sources. The average weighted capacity factor of industrial process boilers in California was derived from the analysis of industrial and commercial boilers conducted by Energy and Environmental Analysis, Inc. for the Oak Ridge National Laboratory (ORNL) in 2005; the analysis utilized the gross domestic product (GDP) of each industry in California and the total U.S. sourced from the Bureau of Economic Analysis. The number of boilers in California by industry is estimated by multiplying the total number of boilers in the U.S. by the California GDP as a percent of the total U.S. GDP. A weighting factor represents the percent of estimated number of boilers in California in each industry as a percent of the total estimated number of boilers in CA.

Average Boiler Capacity Factor, by Industry

| **Industry** | **Capacity Factor (%) [[11]](#footnote-11)** | **Number of Boilers  (Total U.S.) [[12]](#footnote-12)** | **CA Industry GDP as % of Total U.S. Industry GDP (2006) [[13]](#footnote-13)** | **Estimated # of Boilers in CA** | **Weighting Factor (%)** |
| --- | --- | --- | --- | --- | --- |
| Food | 31% | 10,610 | 9.7% | 1,030 | 25.7% |
| Paper | 66% | 3,460 | 4.3% | 149 | 3.7% |
| Chemicals | 50% | 11,980 | 8.8% | 1,055 | 26.2% |
| Refining | 25% | 1,200 | 21.5% | 258 | 6.5% |
| Metals | 47% | 3,330 | 4.5% | 150 | 3.7% |
| Other | 44% | 12,435 | 11.1% | 1,374 | 34.2% |
| **Total** |  | **43,015** |  | **4,016** | **100.0%** |
| Average Capacity Factor | 43.8% |  |  |  |  |
| Weighted Average Capacity Factor | 41.9% |  |  |  |  |

**Annual Operating Hours.** Annual operating hours for this analysis were adopted from the 2017 ESPI Impact Evaluation. The operating hours were determined from onsite visits for at seven of eight sites in the PG&E service area that were included in the ex post evaluation study.

**Boiler Combustion Efficiency.** As shown, the baseline boiler efficiency adopted for this analysis is based upon the minimum efficiency required by the California Building Energy Efficiency Standards (Title 24).

The measure case thermal efficiency values for boilers with single-stage and dual-stage economizers were derived from calculations and data collected from ten economizer applications submitted for incentives to the Southern California Gas Company (SCG) commercial and industrial calculated incentive program (vendors provided cutsheet data for five of the actual projects) . Sample calculations are shown in the following tables.

Example #1: Non-Condensing, Feedwater Economizer

A project completed by the SCG in 2018 at a refining facility in Bakersfield, California, provided data on a feedwater economizer.[[14]](#footnote-14) The project included the installation of new steam boiler and a feedwater (single-stage) economizer. Data was recorded for the boiler exhaust condition from upstream and downstream the economizer and were used in the post-installation report.

According to the plant operating condition and data presented in the figures below, the feedwater economizer shows a gain of 2% in boiler efficiency. The ex ante savings calculations showed an energy savings of 52,700 therms per year for a steam boiler of 23,679 MBtu/hr input capacity (2.23 therms/MBtu/hr).

|  |
| --- |
|  |
| Refinery System Condition Before the Economizer Inlet  *Net Combustion Efficiency = 84.4%* |

|  |
| --- |
|  |
| Refinery System Condition After the Economizer  Net Combustion Efficiency = 86.4% |

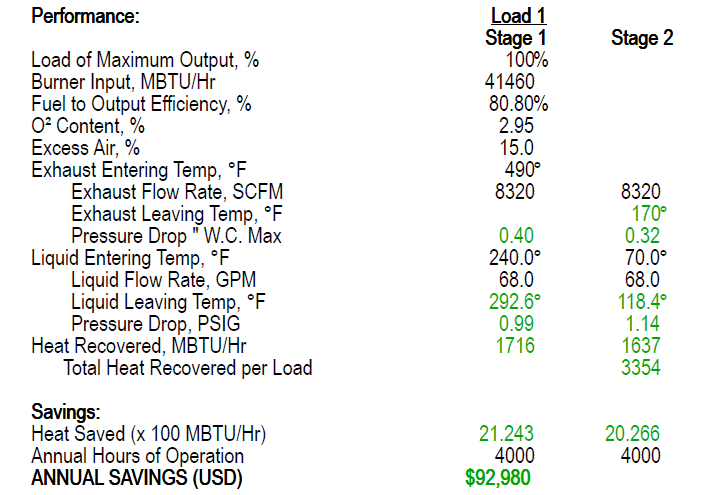
Feedwater Economizer for a Steam Boiler at Refining facility

| **Use of a Non-Condensing Economizer for a Boiler** | | | |
| --- | --- | --- | --- |
| **The tool is applicable to economizers and other flue-gas-to-water heat exchangers *when the water vapor in***  ***flue gas is not condensed, and heat exchanger effectiveness is known*.** | | | |
| 11 | Current boiler energy use - ***average value*** | 23 | MM Btu/hr |
| 12 | Boiler operating hours per year | 8,760 | Hrs./year |
| 13 | Flue gas temperature (hot-side inlet) to the economizer | 371 | Deg. F. |
| 14 | Oxygen in flue gas (%, dry basis) from the boiler | 3.1% | % |
| 15 | Excess air (%) | 15.1% | % |
| 16 | Feed water (cold-side) water flow rate | 11,579 | lbs./hr |
| 17 | Feed water (cold-side) water flow rate | 23.15 | gpm |
| 18 | Feed water (cold-side) pressure | 150 | psig |
| 19 | Feed water (cold-side) inlet temperature | 225 | Deg. F. |
| 20 | Displaced hot water (deaerator) heater efficiency (%) | 84% | % |
| 21 | Economizer (Heat exchanger) effectiveness (%) | 60% | % |
| 22 | Heat transferred to cold feed water | 507,742 | Btu/hr. |
| 23 | Flue gas (hot-side) outlet temperature | 283 | Deg. F. |
| 24 | Feed water outlet temperature | 269 | Deg. F. |
| 25 | Energy savings (%) | 2.7% | % |
| 26 | **Annual energy savings** | **5,270** | **MM Btu/year** |
| 27 | Energy (natural gas) cost | $8.00 | $/MM Btu |
| 28 | **Annual cost savings** | **$42,159** | **$/year** |
| 29 | **Annual CO2 savings based on natural gas as fuel** | **308** | **Tons/year** |

Example #2: Dual-Stage Economizer

A national vendor of heat recovery systems provided project data on a two-stage exhaust economizer. The feedwater and makeup water preheater and heat recovery calculations are presented below.

1,000 Horsepower Boiler Exhaust Economizer Savings Calculations



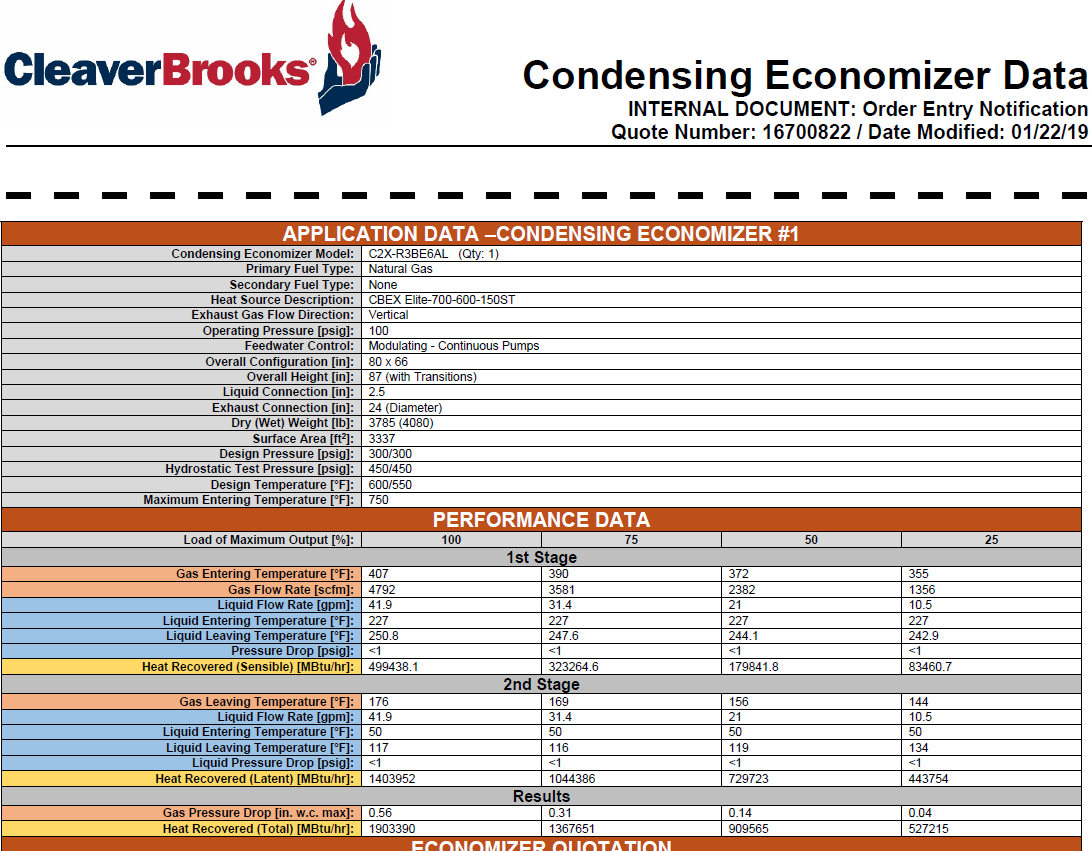
Project Data Submitted by National Vendor of Heat Recovery Systems

| Blue indicates inputs, Green indicates reference, Black indicates calculated | | | | |
| --- | --- | --- | --- | --- |
|  | **Parameter / Calculation** | **Value** | **Units** | **Source** |
|  | ***Reference Values*** |  |  |  |
| A | Density of Liquid Water = | 8.34 | lbm/gallon | Reference |
| B | Specific Heat of Liquid Water = | 1.0 | BTU/lbm-F | Reference |
| C | Stack Exhaust Specific Heat = | 0.2647 | Btu/lb/°F | @ stack temp |
| D | Stack Exhaust Density = | 0.0429 | Lb/ft^3 | @ stack temp |
| E | Steam Enthalpy = | 970 | Btu/lb | (1150-180) @212°F sat. |
| F | kBTU to therm | 100 | kBTU/therm | Reference |
| G | Steam Boiler HP | 1,000 | BHP | Specification |
| H | 1 Boiler HP | 33,475 | Btuh | Constant |
| I | Boiler thermal efficiency = | **80.8%** |  | Reference |
|  | ***Baseline Calculation*** |  |  |  |
| J | Boiler Connected Load = | 33,475 | kBtu/hr | =G\*H |
| K | Boiler Rated Input Capacity = | 41,429 | kBtu/hr | =J/I |
| L | Operating Hours = | 4,000 | hr/yr | Reference |
| M | Load of Maximum Output = | **100%** | % | Specification |
|  | ***Flow Rate Calculation*** |  |  |  |
| N | Flue Exhaust Flow Rate = | 8,320 | SCFM | Spec |
| O | Steam Flow Rate = | 34,510 | Lbm/hr | =J\*1000\*M/E |
| P | Natural gas consumption = | 41,429,455 | Btu/lb | =O\*E/I |
| Q | Feedwater Flow Rate = | 68.0 | gallons/min | Spec |
|  | ***Stage 1*** |  |  |  |
| R | Exhaust Flow Rate = | 23,279 | lbm/hr | =N\*D\*60 |
| S | Inlet stack temperature = | 490 | °F | Specification |
| T | Outlet stack temperature = | 200 | °F | (trial & error) |
| U | Feedwater Flow Rate = | 34,027 | lbm/hr | =Q\*A\*60 |
| V | Feedwater Inlet Temperature = | 240 | °F | Spec |
| W | Feedwater Outlet Temperature = | 292 | °F | Spec |
| X | **Sensible heat load =** | 1,786,966 | Btu/hr | =R\*C\*(S-T) |
|  | ***Stage 2*** |  |  |  |
| Y | Inlet stack temperature = | 200 | °F | =T |
| Z | Outlet stack temperature = | 170 \* | °F | Spec |
| AA | **Sensible heat load =** | 184,859 | Btu/hr | =R\*C\*(Y-Z) |
| AB | Water vapor flow @ inlet = | 2,561 | Lbm/hr | =R\*11% |
| AC | Water vapor flow @ outlet = | 1,057 | Lbm/hr | =R\*4.5% |
| AD | Condensed Water = | 1,504 | Lbm/hr | =AB-AC |
| AE | **Latent heat load =** | 1,458,709 | Btu/hr | =AD\*E |
| AF | **Stage-2, Sensible + Latent heat Load =** | 1,643,567 | Btu/hr | =AA+AE |
|  | ***Dual-Stages*** |  |  |  |
| AG | **Total Recovered heat =** | 3,430,533 | Btu/hr | =X+AF |
| AH | **Economizer Fuel savings =** | 4,245,709 | Btu/hr | =AG/I |
| AI | **Proposed gas consumption =** | 37,183,746 | Btu/hr | =P-AH |
| AJ | **Annual NG Therm Savings =** | **169,828** | therms/yr | =AH\*L/10^5 |
| AK | **Dual-Stage efficiency =** | **90.0%** |  | =O\*E/AI |
| AL | **Final efficiency improvement =** | **9.2%** |  | =AK-I |
| AM | **Dual-Stage Economizer energy savings =** | **4.10** | therms/kBtuh input cap. | =AJ/K |
|  |  |  |  |  |

\* The calculations show that a certain amount of the water vapor that is carried by the flue stack changes phase and condenses when it passes across the tubes carrying the cold make-up water. The “bulk” outlet stack temperature was measured at 170°F due to the presence of uncondensed water vapor in the flue stack leaving the economizer.

Example #3: Dual-Stage Economizer

A steam boiler manufacturer provided design data for one of their projects on two-stage exhaust economizer. The feedwater and makeup water preheater application data and heat recovery calculations are presented below.



Project data submitted by Boiler Manufacturer

| Blue indicates inputs, Green indicates reference, Black indicates calculated | | | | | |
| --- | --- | --- | --- | --- | --- |
|  | **Parameter / Calculation** | **Value1** | **Value2** | **Units** | **Source** |
|  | ***Reference Values*** |  |  |  |  |
| A | Density of Liquid Water = | 8.34 | 8.34 | lbm/gallon | Reference |
| B | Specific Heat of Liquid Water = | 1.0 | 1.0 | BTU/lbm-F | Reference |
| C | Stack Exhaust Specific Heat = | 0.2624 | 0.2612 | Btu/lb/°F | @ stack temp |
| D | Stack Exhaust Density = | 0.0460 | 0.0481 | Lb/ft^3 | @ stack temp |
| E | Steam Enthalpy = | 970 | 970 | Btu/lb | (1150-180) @212°F sat. |
| F | kBTU to therm | 100 | 100 | kBTU/therm | Reference |
| G | Steam Boiler HP | 600 | 600 | BHP | Specification |
| H | 1 Boiler HP | 33,475 | 33,475 | Btuh | Constant |
| I | Boiler thermal efficiency = | **82%** | **82%** |  | Reference |
|  | ***Baseline Calculation*** |  |  |  |  |
| J | Boiler Connected Load = | 20,085 | 20,085 | kBtu/hr | =G\*H |
| K | Boiler Rated Input Capacity = | 24,494 | 24,494 | kBtu/hr | =J/I |
| L | Operating Hours = | 4,000 | 4,000 | hr/yr | Reference |
| M | Load of Maximum Output = | **100%** | **50%** | % | Specification |
|  | ***Flow Rate Calculation*** |  |  |  |  |
| N | Flue Exhaust Flow Rate = | 4,792 | 2,382 | SCFM | Spec |
| O | Steam Flow Rate = | 20,706 | 10,353 | Lbm/hr | =J\*1000\*M/E |
| P | Natural gas consumption = | 24,493,902 | 12,246,951 | Btu/lb | =O\*E/I |
| Q | Feedwater Flow Rate = | 41.9 | 21.0 | gallons/min | Spec |
|  | ***Stage 1*** |  |  |  |  |
| R | Exhaust Flow Rate = | 13,238 | 6,872 | lbm/hr | =N\*D\*60 |
| S | Inlet stack temperature = | 407 | 372 | °F | Specification |
| T | Outlet stack temperature = | 270 | 272 | °F | (trial & error) |
| U | Feedwater Flow Rate = | 20,967 | 10,508 | lbm/hr | =Q\*A\*60 |
| V | Feedwater Inlet Temperature = | 227 | 227 | °F | Spec |
| W | Feedwater Outlet Temperature = | 250 | 244 | °F | Spec |
| X | **Sensible heat load =** | 475,890 | 179,504 | Btu/hr | =R\*C\*(S-T) |
|  | ***Stage 2*** |  |  |  |  |
| Y | Inlet stack temperature = | 270 | 272 | °F | =T |
| Z | Outlet stack temperature\* = | 176 | 156 | °F | Spec |
| AA | **Sensible heat load =** | 326,523 | 208,225 | Btu/hr | =R\*C\*(Y-Z) |
| AB | Water vapor flow @ inlet = | 1,456 | 756 | Lbm/hr | =R\*11% |
| AC | Water vapor flow @ outlet = | 348 | 220 | Lbm/hr | =R\*2.63% |
| AD | Condensed Water = | 1,108 | 536 | Lbm/hr | =AB-AC |
| AE | **Latent heat load =** | 1,074,780 | 519,957 | Btu/hr | =AD\*E |
| AF | **Stage-2, Sensible + Latent heat Load =** | 1,401,303 | 728,182 | Btu/hr | =AA+AE |
|  | ***Dual-Stages*** |  |  |  |  |
| AG | **Total Recovered heat =** | 1,877,193 | 907,686 | Btu/hr | =X+AF |
| AH | **Economizer Fuel savings =** | 2,289,260 | 1,106,934 | Btu/hr | =AG/I |
| AI | **Proposed gas consumption =** | 22,204,642 | 11,140,017 | Btu/hr | =P-AH |
| AJ | **Annual NG Therm Savings =** | **91,570** | **44,277** | therms/yr | =AH\*L/10^5 |
| AK | **Dual-Stage efficiency =** | **90.5%** | **90.1%** |  | =O\*E/AI |
| AL | **Final efficiency improvement =** | **8.5%** | **8.1%** |  | =AK-I |
| AM | **Dual-Stage Economizer energy savings =** | **3.74** | **1.81** | therms/kBtuh input cap. | =AJ/K |
|  |  |  |  |  |  |

\* The calculations show that about 30% of the water vapor in the flue gas were not condensed in stage-2 and are carried by the flue gas leaving the condensing economizer. Therefore, for the given stack flow rate at 100% and 50% loading, the bulk outlet stack temperature was measured at 176°F & 156°F, respectively. For details, please see the excel calculations.

Life Cycle

Effective useful life (EUL) is an estimate of the median number of years that a measure installed through a program is still in place and operable. Remaining useful life (RUL) is an estimate of the median number of years that a technology or piece of equipment replaced or altered by an energy efficiency program would have remained in service and operational had the program intervention not caused the replacement or alteration.

The methodology to calculate the RUL conforms with Version 5 of the Energy Efficiency Policy Manual, which recommends “one-third of the effective useful life in DEER as the remaining useful life until further study results are available to establish more accurate values.”[[15]](#footnote-15) This approach provides a reasonable RUL estimate without the requiring any a priori knowledge about the age of the equipment being replaced.[[16]](#footnote-16) Further, as per Resolution E-4807, the California Public Utilities Commission (CPUC) revised add-on measures so that the EUL of the measure is equal to the lower of the RUL of the modified system or equipment or the EUL of the add-on component.” [[17]](#footnote-17)

The EUL and RUL for a process boiler is specified below. The RUL value is only applicable to the first baseline period for a retrofit measure with an applicable code baseline.

Effective Useful Life and Remaining Useful Life

|  |  |  |
| --- | --- | --- |
| **Parameter** | **Value** | **Source** |
| EUL (yrs) | 20.0 | California Public Utilities Commission (CPUC), Energy Division. 2003. *Energy Efficiency Policy Manual v 2.0.* Page. 16.  California Public Utilities Commission (CPUC), Energy Division. 2014. “DEER2014-EUL-table-update\_2014-02-05.xlsx” |
| RUL (yrs) | 6.67 |  |

Base Case Material Cost ($/unit)

The base case equipment cost for the measure is $0.

Measure Case Material Cost ($/unit)

The measure case material cost calculated as the average of equipment cost estimates provided by contractors for projects installed in the Southern California Gas Company (SCG) service area in 2016 and 2017. The measure cost was based on contractors’ invoices for equipment installed in several SCG’s C&I projects. Equipment cost per kBtu/hr for Tier 1 single-stage economizer (3 models), and Tier 2 dual-stage economizer (8 models).

Measure Case Material Cost Inputs

|  |  |  |
| --- | --- | --- |
| **Parameter** | **Value ($/kBtu/hr input capacity)** | **Source** |
| A. Single-Stage Economizer | $0.75 | Southern California Gas Company (SCG). 2019. “SWPR007-01 Calculations for Single and Dual Stage Economizers.xlsx.” |
| B. Dual-Stage Economizer | $3.05 |

Base Case Labor Cost ($/unit)

The base case installation labor cost is $0.

Measure Case Labor Cost ($/unit)

The measure labor cost was calculated as the average of installation cost estimates provided by contractors for projects installed in the Southern California Gas Company (SCG) service area in 2016 and 2017. The labor installation cost was based on contractors’ invoices for equipment installed in several SCG’s C&I projects.

Measure Installation Labor Cost Inputs

|  |  |  |
| --- | --- | --- |
| **Parameter** | **Value** | **Source** |
| A. Single-Stage Economizer | $1.05 / kBtuh input Cap. | Southern California Gas Company (SCG). 2019. “SWPR007-01 Calculations for Single and Dual Stage Economizers.xlsx.”. |
| B. Dual-Stage Economizer | $1.03 / kBtuh input Cap. |

Net-to-Gross (NTG)

The net-to-gross (NTG) ratio represents the portion of gross impacts that are determined to be directly attributed to a specific program intervention. This NTG value is based upon the average of all NTG ratios for all evaluated 2006 – 2008 commercial, industrial, and agriculture programs, as documented in the 2011 DEER Update Study conducted by Itron, Inc. This sector average NTG (“default NTG”) is applicable to all energy efficiency measures that have been offered through commercial, industrial, and agriculture sector programs for more than two years and for which impact evaluation results are not available.

Net-to-Gross Ratios

|  |  |  |
| --- | --- | --- |
| **Parameter** | **Value** | **Source** |
| Com-Default>2yrs | 0.60 | Itron, Inc. 2011. *DEER Database 2011 Update Documentation.* Prepared for the California Public Utilities Commission. Page 15-4 Table 15-3. |
| Ind-Default>2yrs | 0.60 |
| Agric-Default>2yrs | 0.60 |

Gross Savings Installation Adjustment (GSIA)

The gross savings installation adjustment (GSIA) represents the ratio of the number of verified installations of the measure to the number of claimed installations reported by the utility. This factor varies by end use, sector, technology, application, and delivery method. This GSIA rate is the current “default” rate specified for measures for which an alternative GSIA has not been estimated and approved.

Gross Savings Installation Adjustment Rates

|  |  |  |
| --- | --- | --- |
| **Parameter** | **Value** | **Source** |
| GSIA | 1.0 | California Public Utilities Commission (CPUC), Energy Division. 2013. *Energy Efficiency Policy Manual Version 5*. Page 31. |

Non-Energy Impacts

Non-energy benefits for this measure have not been quantified.

DEER Differences Analysis

This section provides a summary of inputs and methods used from the Database of Energy Efficient Resources (DEER), and the rationale for inputs and methods that are not DEER-based.

DEER Difference Summary

|  |  |
| --- | --- |
| **DEER Item** | **Comment / Used for Workpaper** |
| Modified DEER methodology | No |
| Scaled DEER measure | No |
| DEER Base Case | No |
| DEER Measure Case | No |
| DEER Building Types | No |
| DEER Operating Hours | No |
| DEER eQUEST Prototypes | No |
| DEER Version | No |
| Reason for Deviation from DEER | N/A |
| DEER Measure IDs Used | N/A |
| NTG | Source: DEER2020. The NTG of 0.60 is associated with NTG ID: *Com-Default>2, Ind-Default>2, Agric-Default>2* |
| GSIA | Source: DEER. The GSIA of 1.0 is associated with GSIA ID: *Def-GSIA* |
| EUL/RUL | Source: DEER2020. The value of 20 years is associated with EUL ID: *PrcHt-StmBlr* |

Revision History

Measure Characterization Revision History

|  |  |  |  |
| --- | --- | --- | --- |
| **Revision Number** | **Date** | **Primary Author, Title, Organization** | **Revision Summary and Rationale for Revision**  **Effective Date and Approved By** |
| 01 | 08/30/2019 | Raad Bashar,  SoCalGas. | Draft of consolidated text for this statewide measure is based upon:  WPSCGNRPH180608A, Revision 0 (August 30, 2019) |
| 5/27/2020 | Eduardo Reynoso, SDG&E | Workpaper measure adoption by SDG&E, no changes to energy efficiency savings or cost. Updated Ex-ante Implementation data table. No other changes. |
| 01/29/2021 | Tai Voong,  PG&E | Workpaper measure adoption by PG&E, no changes to energy efficiency savings or cost. Updated Ex-ante Implementation data table. No other changes. |

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3. U.S. Department of Energy (DOE), Energy Efficiency and Renewable Energy, Advanced Manufacturing Office. 2012. *Energy Tips: STEAM. Steam Tip Sheet #26B. Considerations When Selecting a Condensing Economizer.* DOE/GO0102012-3393. January. [↑](#footnote-ref-3)
4. U.S. Department of Energy (DOE), Energy Efficiency and Renewable Energy, Advanced Manufacturing Office. 2012. *Energy Tips: STEAM. Steam Tip Sheet #26A.* *Consider Installing a Condensing Economizer.* DOE/GO0102012-3393. January. Page 1.

   Zaidi, A. (Enbridge Gas Distribution, Inc.). 2008. “Boiler Heat Recovery with Condensing Economizers.” Presented to ESC TMAF. February 20. [↑](#footnote-ref-4)
5. U.S. Department of Energy (DOE), Energy Efficiency and Renewable Energy, Advanced Manufacturing Office. 2012. *Energy Tips: STEAM. Steam Tip Sheet #26A.* *Consider Installing a Condensing Economizer.* DOE/GO0102012-3393. January. [↑](#footnote-ref-5)
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7. U.S. Department of Energy (DOE), Energy Efficiency and Renewable Energy, Advanced Manufacturing Office. 2012. *Energy Tips: STEAM. Steam Tip Sheet #26A.* *Consider Installing a Condensing Economizer.* DOE/GO0102012-3393. January.

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9. California Energy Commission (CEC). 2018. 2019 Building Energy Efficiency Standards for Residential and Nonresidential Buildings (Title 24). CEC-400-2018-020-CMF. Table 110.2-K.

   California Energy Commission (CEC). 2019. California Code of Regulations Title 20 Public Utilities and Energy. CEC-140-2019-002. Table E-4. [↑](#footnote-ref-9)
10. Itron and ERS. 2019. *2017 Small/Medium Commercial Sector ESPI Impact Evaluation Draft Report.* Prepared for the California Public Utilities Commission. March 1. [↑](#footnote-ref-10)
11. Energy and Environmental Analysis, Inc. 2005. *Characterization of the US Industrial/Commercial Boiler Population*. Conducted for the Oak Ridge National Laboratory. Chapter 2. [↑](#footnote-ref-11)
12. Energy and Environmental Analysis, Inc. 2005. *Characterization of the US Industrial/Commercial Boiler Population*. Conducted for the Oak Ridge National Laboratory. Table 2-1, page 2-1. [↑](#footnote-ref-12)
13. U.S. Department of Commerce, Bureau of Economic Analysis. 2008. "Regional Economic Accounts: Gross Domestic Products by State." http://www.bea.gov/regional/gsp/. Accessed on January 8, 2008. [↑](#footnote-ref-13)
14. Southern California Gas Company (SCG). 2018. *Energy Efficiency Calculation Incentive Program (EECIP) Post-Installation Report. Report/Project No.: CUSTOMER X1D.16S.*  [↑](#footnote-ref-14)
15. California Public Utilities Commission (CPUC), Energy Division. 2013. *Energy Efficiency Policy Manual Version 5*. Page 32. [↑](#footnote-ref-15)
16. KEMA, Inc. 2008. "Summary of EUL-RUL Analysis for the April 2008 Update to DEER." Memorandum submitted to Itron, Inc. [↑](#footnote-ref-16)
17. California Public Utilities Commission (CPUC). 2016. Resolution E-4807. December 16. Page 13.   [↑](#footnote-ref-17)