



PROCESS HEAT
STEAM BOILER ECONOMIZER, INDUSTRIAL
SWPR007-01

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MEASURE NAME

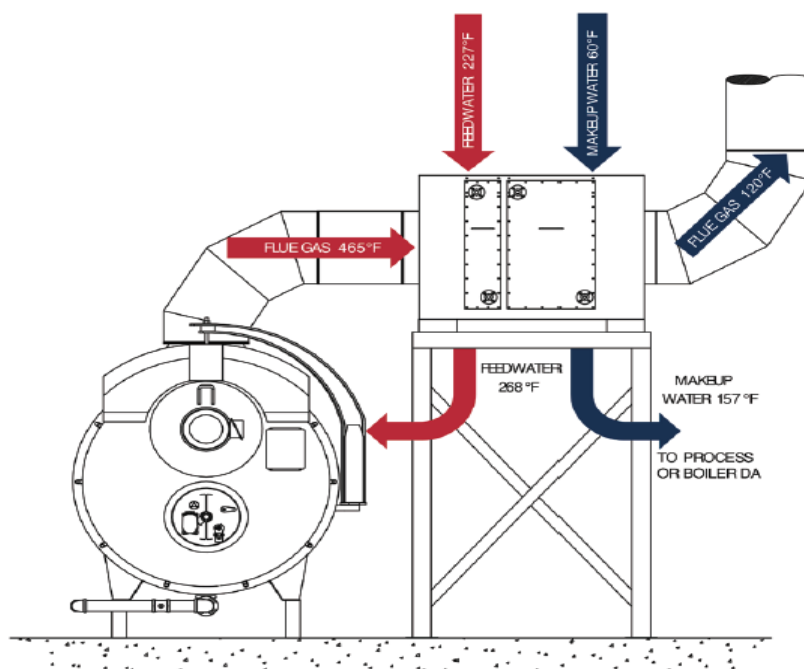
Steam Boiler Economizer, Industrial

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 & NO_x) and rapid return on investment.



*Typical and actual values will vary depending on boiler model, size and operating conditions.

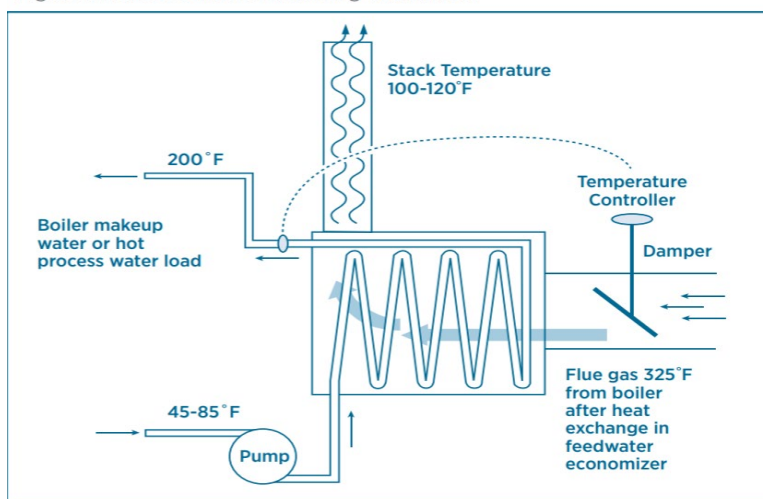
Two-Stage Heat Recovery System¹

¹ Cleaver Brooks. (n.d.) C2X-HE.

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 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

Figure 1. Indirect contact condensing economizer



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

² U.S. Department of Energy (DOE), Energy Efficiency and Renewable Energy, Advanced Manufacturing Office. 2012. *Energy Tips: STEAM. Steam Tip Sheet #3. Use Feedwater Economizers for Waste Heat Recovery.* DOE/GO0102012-3393. January.

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.

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

Boiler Efficiency of Condensing Economizers⁵

System	Combustion Efficiency @ 4% Excess O ₂ (%)	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

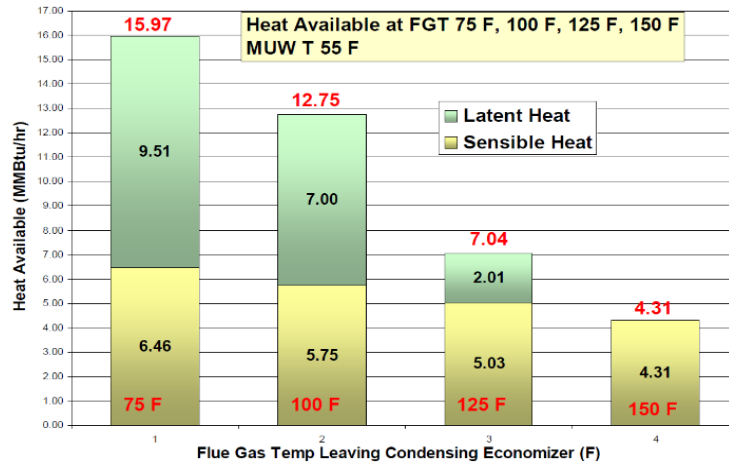
The total heat recovered by the make-up water also depends on its flow rate (gpm or lb/hr) and the conditions of the flue gas leaving the economizer, as presented by Aqeel Zaidi, P.Eng., of Enbridge Gas Distribution Inc.⁶ The figure below shows the available heat in the stack at different exhaust temperatures,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

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.

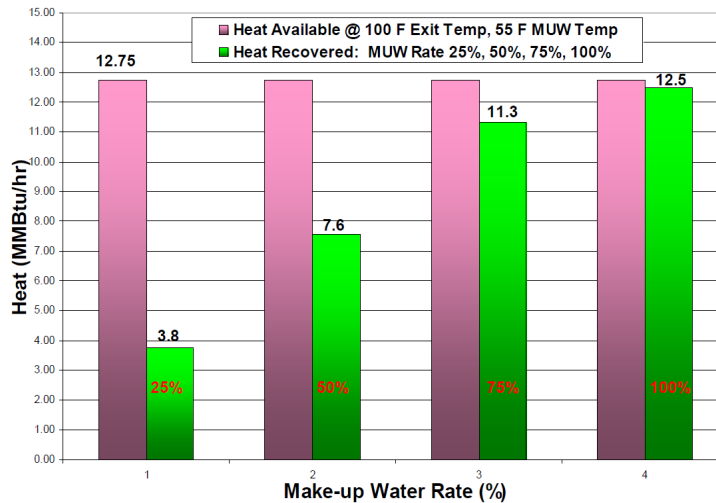
⁵ U.S. Department of Energy (DOE), Energy Efficiency and Renewable Energy, Advanced Manufacturing Office. 2012. *Energy Tips: STEAM. Steam Tip Sheet #26A. Consider Installing a Condensing Economizer*. DOE/GO0102012-3393. January.

⁶ Zaidi, A. (Enbridge Gas Distribution, Inc.). 2008. “Boiler Heat Recovery with Condensing Economizers.” Presented to ESC TMAF. February 20.



Energy Available from a 100,000 lb/hr Natural Gas-Fired Steam Boiler (MMBtu/hr)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 Size⁸

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.

Zaidi, A. (Enbridge Gas Distribution, Inc.). 2008. "Boiler Heat Recovery with Condensing Economizers." Presented to ESC TMAF. February 20.

⁸ 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.

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

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

Zaidi, A. (Enbridge Gas Distribution, Inc.). 2008. “Boiler Heat Recovery with Condensing Economizers.” Presented to ESC TMAF. February 20.

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.

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.

$$UES = UEC_{base} - UEC_{measure}$$

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

$UEC_{base} =$ Unit energy consumption, base case, therms/kBtu/hr input rating

$UEC_{measure} =$ Unit energy consumption, measure case, therms/kBtu/hr input rating

$$UEC_{baseline} = CF \times HOURS \times CE_{base}$$

$$UEC_{measure} = UEC_{baseline} \times \frac{CE_{baseline}}{CE_{measure}}$$

$UEC =$ 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. <i>2017 Small/Medium Commercial Sector ESPI Impact Evaluation Draft Report</i> . 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. <i>2017 Small/Medium Commercial Sector ESPI Impact Evaluation Draft Report</i> . Prepared for the California Public Utilities Commission. March 1. Page 5-20, Table 5-19.

Input	Baseline Value	Source
Steam Boiler Thermal Efficiency (TE)	79%	California Energy Commission (CEC). 2018. <i>2019 Building Energy Efficiency Standards for Residential and Nonresidential Buildings (Title 24)</i> . CEC-400-2018-020-CMF. Table 110.2-K. California Energy Commission (CEC). 2019. <i>California Code of Regulations Title 20 Public Utilities and Energy</i> . 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. <i>2017 Small/Medium Commercial Sector ESPI Impact Evaluation Draft Report</i> . 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. <i>2017 Small/Medium Commercial Sector ESPI Impact Evaluation Draft Report</i> . 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 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

¹⁰ Itron and ERS. 2019. *2017 Small/Medium Commercial Sector ESPI Impact Evaluation Draft Report*. Prepared for the California Public Utilities Commission. March 1.

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	Number of Boilers (Total U.S.) ¹²	CA Industry GDP as % of Total U.S. Industry GDP (2006) 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.

¹¹ Energy and Environmental Analysis, Inc. 2005. *Characterization of the US Industrial/Commercial Boiler Population*. Conducted for the Oak Ridge National Laboratory. Chapter 2.

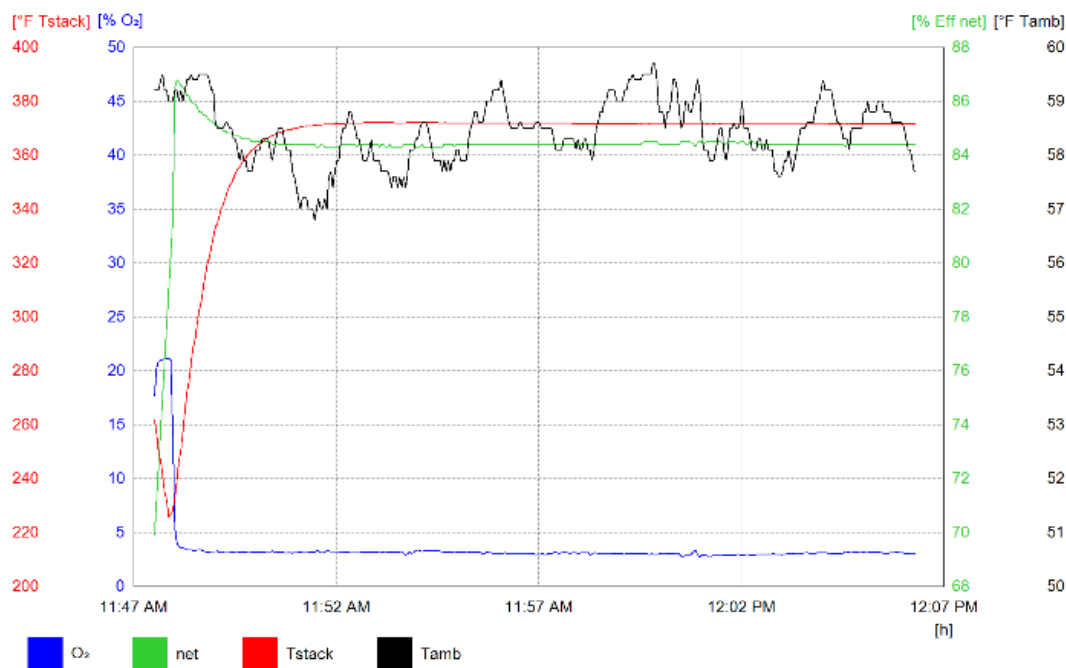
¹² Energy and Environmental Analysis, Inc. 2005. *Characterization of the US Industrial/Commercial Boiler Population*. Conducted for the Oak Ridge National Laboratory. Table 2-1, page 2-1.

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.

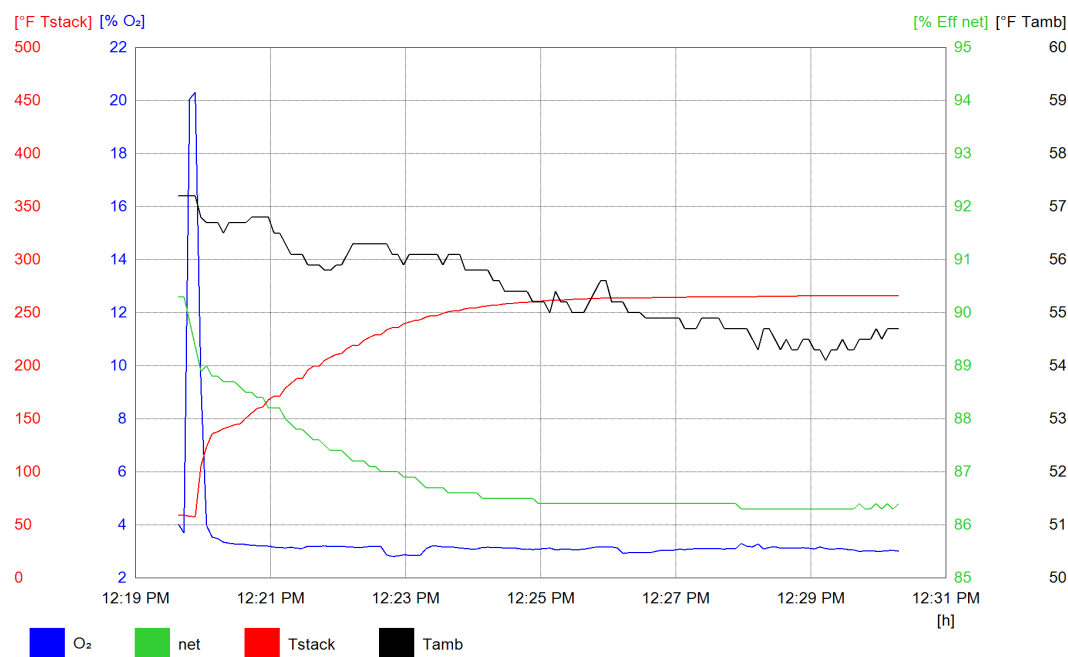
Example #1: Non-Condensing, Feedwater Economizer

A project completed by the SCG in 2018 at a refining facility in Bakersfield, California, provided data on a feedwater economizer.¹⁴ 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).



¹⁴ Southern California Gas Company (SCG). 2018. *Energy Efficiency Calculation Incentive Program (EECIP) Post-Installation Report*. Report/Project No.: CUSTOMER X1D.16S.



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 <i>when the water vapor in flue gas is not condensed, and heat exchanger effectiveness is known.</i>			
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

Performance:	Load 1 Stage 1	Stage 2
Load of Maximum Output, %	100%	
Burner Input, MBTU/Hr	41460	
Fuel to Output Efficiency, %	80.80%	
O ² Content, %	2.95	
Excess Air, %	15.0	
Exhaust Entering Temp, °F	490°	
Exhaust Flow Rate, SCFM	8320	8320
Exhaust Leaving Temp, °F		170°
Pressure Drop " W.C. Max	0.40	0.32
Liquid Entering Temp, °F	240.0°	70.0°
Liquid Flow Rate, GPM	68.0	68.0
Liquid Leaving Temp, °F	292.6°	118.4°
Pressure Drop, PSIG	0.99	1.14
Heat Recovered, MBTU/Hr	1716	1637
Total Heat Recovered per Load		3354
Savings:		
Heat Saved (x 100 MBTU/Hr)	21.243	20.266
Annual Hours of Operation	4000	4000
ANNUAL SAVINGS (USD)	\$92,980	

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

Blue indicates inputs, Green indicates reference, Black indicates calculated				
	Parameter / Calculation	Value	Units	Source
	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		therms/kBtuh	=AJ/K
	=	4.10	input cap.	

* 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.

APPLICATION DATA –CONDENSING ECONOMIZER #1				
Condensing Economizer Model:	C2X-R3BE6AL (Qty: 1)			
Primary Fuel Type:	Natural Gas			
Secondary Fuel Type:	None			
Heat Source Description:	CBEX Elite-700-600-150ST			
Exhaust Gas Flow Direction:	Vertical			
Operating Pressure [psig]:	100			
Feedwater Control:	Modulating - Continuous Pumps			
Overall Configuration [in]:	80 x 66			
Overall Height [in]:	87 (with Transitions)			
Liquid Connection [in]:	2.5			
Exhaust Connection [in]:	24 (Diameter)			
Dry (Wet) Weight [lb]:	3785 (4080)			
Surface Area [ft²]:	3337			
Design Pressure [psig]:	300/300			
Hydrostatic Test Pressure [psig]:	450/450			
Design Temperature [°F]:	600/550			
Maximum Entering Temperature [°F]:	750			
PERFORMANCE DATA				
Load of Maximum Output [%]:	100	75	50	25
1st Stage				
Gas Entering Temperature [°F]:	407	390	372	355
Gas Flow Rate [scfm]:	4792	3581	2382	1356
Liquid Flow Rate [gpm]:	41.9	31.4	21	10.5
Liquid Entering Temperature [°F]:	227	227	227	227
Liquid Leaving Temperature [°F]:	250.8	247.6	244.1	242.9
Pressure Drop [psig]:	<1	<1	<1	<1
Heat Recovered (Sensible) [MBtu/hr]:	499438.1	323264.6	179841.8	83460.7
2nd Stage				
Gas Leaving Temperature [°F]:	176	169	156	144
Liquid Flow Rate [gpm]:	41.9	31.4	21	10.5
Liquid Entering Temperature [°F]:	50	50	50	50
Liquid Leaving Temperature [°F]:	117	116	119	134
Liquid Pressure Drop [psig]:	<1	<1	<1	<1
Heat Recovered (Latent) [MBtu/hr]:	1403952	1044386	729723	443754
Results				
Gas Pressure Drop [in. w.c. max]:	0.56	0.31	0.14	0.04
Heat Recovered (Total) [MBtu/hr]:	1903390	1367651	909565	527215

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/ft³	@ 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					

Blue indicates inputs, Green indicates reference, Black indicates calculated					
	Parameter / Calculation	Value1	Value2	Units	Source
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 This approach provides a reasonable RUL estimate without the requiring any a priori knowledge about the age of the equipment being replaced.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

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. <i>Energy Efficiency Policy Manual v 2.0</i> . 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).

¹⁵ California Public Utilities Commission (CPUC), Energy Division. 2013. *Energy Efficiency Policy Manual Version 5*. Page 32.

¹⁶ KEMA, Inc. 2008. "Summary of EUL-RUL Analysis for the April 2008 Update to DEER." Memorandum submitted to Itron, Inc.

¹⁷ California Public Utilities Commission (CPUC). 2016. Resolution E-4807. December 16. Page 13.

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. <i>DEER Database 2011 Update Documentation</i> . 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. <i>Energy Efficiency Policy Manual Version 5</i> . 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: <i>Com-Default>2, Ind-Default>2, Agric-Default>2</i>
GSIA	Source: DEER. The GSIA of 1.0 is associated with GSIA ID: <i>Def-GSIA</i>
EUL/RUL	Source: DEER2020. The value of 20 years is associated with EUL ID: <i>PrcHt-StmBlr</i>

REVISION HISTORY

Measure Characterization Revision History

Revision Number	Date	Primary Author, Title, Organization	Revision Summary and Rationale for Revision Effective Date and Approved By
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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.