TECHNICAL SUPPORT DOCUMENT: ENERGY EFFICIENCY PROGRAM FOR CONSUMER PRODUCTS AND COMMERCIAL AND INDUSTRIAL EQUIPMENT:

RESIDENTIAL BOILERS

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CHAPTER 1. INTRODUCTION

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CHAPTER 1. INTRODUCTION

1.1 PURPOSE OF THE DOCUMENT

This technical support document (TSD) is a stand-alone report that provides the technical analyses and results supporting the information presented in the final rule for residential boilers.

1.2 SUMMARY OF THE NATIONAL BENEFITS

DOE's analyses indicate that the adopted AFUE energy conservation standards for residential boilers are expected to save a significant amount of energy. Relative to the case without amended standards, the lifetime energy savings for residential boilers purchased in the 30-year period that begins in the first full year of compliance with the amended standards (2021-2050) amount to 0.16 quadrillion Btu (quads).[a] This represents a savings of 0.6 percent relative to the energy use of these products in the case without amended standards (referred to as the "no-new-standards case").

The cumulative net present value (NPV) of total consumer costs and savings for the amended residential boilers AFUE standards ranges from $0.35 billion to $1.20 billion at 7-percent and 3-percent discount rates, respectively. This NPV expresses the estimated total value of future operating-cost savings minus the estimated increased product costs for residential boilers purchased in 2021–2050.

In addition, the amended AFUE standards for residential boilers are expected to have significant environmental benefits. DOE estimates that the AFUE standards would result in cumulative emission reductions (over the same period as for energy savings) of 9.33 million metric tons (Mt) [b] of carbon dioxide (CO_2), 2.075 thousand tons of sulfur dioxide (SO_2), 122.3 tons of nitrogen oxides (NO_X), 71.9 thousand tons of methane (CH_4), 0.09 thousand tons of nitrous oxide (N_2O), and 0.45 pounds of mercury (Hg).[c] The cumulative reduction in CO_2 emissions through 2030 amounts to 0.77 Mt, which is equivalent to the emissions resulting from the annual electricity use of more than 70,000 homes.

The value of the CO_2 reductions is calculated using a range of values per metric ton of CO_2 (otherwise known as the "Social Cost of Carbon", or SCC) developed by a Federal

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[a] A quad is equal to 1015 British thermal units (Btu). The quantity refers to full-fuel-cycle (FFC) energy savings. FFC energy savings includes the energy consumed in extracting, processing, and transporting primary fuels (*i.e.*, coal, natural gas, petroleum fuels), and, thus, presents a more complete picture of the impacts of energy efficiency standards. For more information on the FFC metric, see chapter 10.

[b] A metric ton is equivalent to 1.1 short tons. Results for gases other than CO2 are presented in short tons.

[c] DOE calculated emissions reductions relative to the no-new-standards-case, which reflects key assumptions in the Annual Energy Outlook 2015 (AEO 2015) Reference case, which generally represents current legislation and environmental regulations for which implementing regulations were available as of October 31, 2014. DOE notes that the amended AFUE standards are estimated to cause a very slight increase in mercury emissions due to associated increase in boiler electricity use.

interagency working group (IWG).[d] The derivation of the SCC values is discussed in chapter 14. Using discount rates appropriate for each set of SCC values, DOE estimates that the net present monetary value of the CO_2 emissions reduction (not including CO_2-equivalent emissions of other gases with global warming potential) from residential boiler AFUE standards is between $0.053 billion and $0.802 billion, with a value of $0.263 billion using the central SCC case represented by $40.0/t in 2015. DOE also estimates that the net present monetary value of the NO_X emissions reduction to be $0.109 billion at a 7-percent discount rate, and $0.328 billion at a 3-percent discount rate.[e]

Table 1.2.1 summarizes the national economic benefits and costs expected to result from the adopted AFUE standards for residential boilers.

[d] Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Interagency Working Group on Social Cost of Carbon, United States Government (May 2013; revised July 2015) (Available at: https://www.whitehouse.gov/sites/default/files/omb/inforeg/scc-tsd-final-july-2015.pdf).

[e] DOE estimated the monetized value of NO_X emissions reductions using benefit per ton estimates from the Regulatory Impact Analysis titled, "Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants," published in June 2014 by EPA's Office of Air Quality Planning and Standards. (Available at: http://www3.epa.gov/ttnecas1/regdata/RIAs/111dproposalRIAfinal0602.pdf.) See chapter 14 for further discussion. Note that the agency is presenting a national benefit-per-ton estimate for particulate matter emitted from the Electricity Generating Unit sector based on an estimate of premature mortality derived from the ACS study (Krewski et al., 2009). If the benefit-per-ton estimates were based on the Six Cities study (Lepuele et al., 2011), the values would be nearly two-and-a-half times larger. Because of the sensitivity of the benefit-per-ton estimate to the geographical considerations of sources and receptors of emissions, DOE intends to investigate refinements to the agency's current approach of one national estimate by assessing the regional approach taken by EPA's Regulatory Impact Analysis for the Clean Power Plan Final Rule. Note that DOE is currently investigating valuation of avoided and SO_2 and Hg emissions.

Table 1.2.1 Summary of National Economic Benefits and Costs of Amended AFUE Energy Conservation Standards for Residential Boilers (TSL 3)*

Category	Present Value *Billion 2014$*	Discount Rate *%*
Benefits		
Consumer Operating Cost Savings	0.500	7
	1.468	3
CO_2 Reduction Value ($12.2/t case)**	0.053	5
CO_2 Reduction Value ($40.0/t case)**	0.263	3
CO_2 Reduction Value ($62.3/t case)**	0.425	2.5
CO_2 Reduction Value ($117/t case)**	0.802	3
NO_x Reduction Value†	0.109	7
	0.328	3
Total Benefits††	0.872	7
	2.058	3
Costs		
Consumer Incremental Installed Costs	0.150	7
	0.270	3
Total Net Benefits		
Including Emissions Reduction Value††	0.722	7
	1.789	3

* This table presents the costs and benefits associated with residential boilers shipped in 2021−2050. These results include benefits to consumers which accrue after 2050 from the products purchased in 2021−2050. The costs account for the incremental variable and fixed costs incurred by manufacturers due to the standard, some of which may be incurred in preparation for the rule.

** The CO_2 values represent global monetized values of the SCC, in 2014$, in 2015 under several scenarios of the updated SCC values. The first three cases use the averages of SCC distributions calculated using 5%, 3%, and 2.5% discount rates, respectively. The fourth case represents the 95th percentile of the SCC distribution calculated using a 3% discount rate. The SCC time series incorporate an escalation factor.

† The $/ton values used for NO_X are described in chapter 14. DOE estimated the monetized value of NO_X emissions reductions using benefit per ton estimates from the Regulatory Impact Analysis titled, "Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants," published in June 2014 by EPA's Office of Air Quality Planning and Standards. (Available at: http://www3.epa.gov/ttnecas1/regdata/RIAs/111dproposalRIAfinal0602.pdf.) See chapter 14 for further discussion. Note that the agency is presenting a national benefit-per-ton estimate for particulate matter emitted from the Electricity Generating Unit sector based on an estimate of premature mortality derived from the ACS study (Krewski et al., 2009). If the benefit-per-ton estimates were based on the Six Cities study (Lepuele et al., 2011), the values would be nearly two-and-a-half times larger. Because of the sensitivity of the benefit-per-ton estimate to the geographical considerations of sources and receptors of emissions, DOE intends to investigate refinements to the agency's current approach of one national estimate by assessing the regional approach taken by EPA's Regulatory Impact Analysis for the Clean Power Plan Final Rule.

†† Total Benefits for both the 3% and 7% cases are derived using the series corresponding to average SCC with 3-percent discount rate ($40.0/t case).

For the adopted standby mode and off mode standards, the lifetime energy savings for residential boilers purchased in the 30-year period that begins in the first full year of compliance

with amended standards (2021-2050) amount to 0.0026 quads. This is a savings of 1.2 percent relative to the standby energy use of these products in the no-new-standards case.

The cumulative NPV of total consumer costs and savings for the adopted standby mode and off mode standards for residential boilers ranges from $0.003 billion to $0.014 billion at 7-percent and 3-percent discount rates, respectively. This NPV expresses the estimated total value of future operating-cost savings minus the estimated increased product costs for residential boilers purchased in 2021–2050.

In addition, the standby mode and off mode standards are expected to have significant environmental benefits. The energy savings are expected to result in cumulative emission reductions (over the same period as for energy savings) of 0.154 Mt of CO_2, 0.087 thousand tons of SO_2, 0.278 thousand tons of NO_X, 0.669 thousand tons of CH_4, 0.0018 thousand tons of N_2O, and 0.642 pounds of Hg. The cumulative reduction in CO_2 emissions through 2030 amounts to 0.013 Mt, which is equivalent to the emissions resulting from the annual electricity use of approximately 1,200 homes.

As noted above, the value of the CO_2 reductions is calculated using a range of values per metric ton of CO_2 (otherwise known as the SCC) developed by a Federal interagency IWG. The derivation of the SCC values is discussed in chapter 14. Using discount rates appropriate for each set of SCC values, DOE estimates that the net present monetary value of the CO_2 emissions reduction from standby mode and off mode standards for residential boilers is between $0.001 billion and $0.013 billion, with a value of $0.004 billion using the central SCC case represented by $40.0/t in 2015. DOE also estimates that the net present monetary value of the NO_X emissions reduction to be $0.0002 billion at a 7-percent discount rate, and $0.0007 billion at a 3-percent discount rate.

Table 1.2.2 summarizes the national economic benefits and costs expected to result from the adopted standby mode and off mode standards for residential boilers.

Table 1.2.2 Summary of National Economic Benefits and Costs of Adopted Standby Mode and Off Mode Energy Conservation Standards for Residential Boilers (TSL 3)*

Category	Present Value *Billion 2014$*	Discount Rate *%*
Benefits		
Consumer Operating Cost Savings	0.007	7
	0.022	3
CO_2 Reduction Value ($12.2/t case)**	0.001	5
CO_2 Reduction Value ($40.0/t case)**	0.004	3
CO_2 Reduction Value ($62.3/t case)**	0.007	2.5
CO_2 Reduction Value ($117/t case)**	0.013	3
NO_x Reduction Value†	0.0002	7
	0.0007	3
Total Benefits††	0.012	7
	0.027	3
Costs		
Consumer Incremental Installed Costs	0.004	7
	0.008	3
Total Net Benefits		
Including Emissions Reduction Value††	0.008	7
	0.019	3

* This table presents the costs and benefits associated with residential boilers shipped in 2021−2050. These results include benefits to consumers which accrue after 2050 from the products purchased in 2021−2050. The costs account for the incremental variable and fixed costs incurred by manufacturers due to the standard, some of which may be incurred in preparation for the rule.

** The CO_2 values represent global monetized values of the SCC, in 2014$, in 2015 under several scenarios of the updated SCC values. The first three cases use the averages of SCC distributions calculated using 5%, 3%, and 2.5% discount rates, respectively. The fourth case represents the 95th percentile of the SCC distribution calculated using a 3% discount rate. The SCC time series incorporate an escalation factor.

† The $/ton values used for NO_X are described in chapter 14. DOE estimated the monetized value of NO_X emissions reductions using benefit per ton estimates from the Regulatory Impact Analysis titled, "Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants," published in June 2014 by EPA's Office of Air Quality Planning and Standards. (Available at: http://www3.epa.gov/ttnecas1/regdata/RIAs/111dproposalRIAfinal0602.pdf.) See chapter 14 for further discussion. Note that the agency is presenting a national benefit-per-ton estimate for particulate matter emitted from the Electricity Generating Unit sector based on an estimate of premature mortality derived from the ACS study (Krewski et al., 2009). If the benefit-per-ton estimates were based on the Six Cities study (Lepuele et al., 2011), the values would be nearly two-and-a-half times larger. Because of the sensitivity of the benefit-per-ton estimate to the geographical considerations of sources and receptors of emissions, DOE intends to investigate refinements to the agency's current approach of one national estimate by assessing the regional approach taken by EPA's Regulatory Impact Analysis for the Clean Power Plan Final Rule.

†† Total Benefits for both the 3% and 7% cases are derived using the series corresponding to average SCC with 3-percent discount rate ($40.0/t case).

The benefits and costs of the adopted energy conservation standards, for residential boiler products sold in 2021-2050, can also be expressed in terms of annualized values. Benefits and

costs for the AFUE standards are considered separately from benefits and costs for the standby mode and off mode electrical consumption standards, because for the reasons explained in the chapter 3, it was not technically feasible to develop a single, integrated standard. The monetary values for the total annualized net benefits are the sum of: (1) the national economic value of the benefits in reduced consumer operating cost, minus (2) the increases in product purchase price and installation costs, plus (3) the value of the benefits of CO_2 and NO_X emission reductions, all annualized.[f]

Although the value of operating cost savings and CO_2 emission reductions are both important, two issues are relevant. First, the national operating cost savings are domestic U.S. consumer monetary savings that occur as a result of market transactions, whereas the value of CO_2 reductions is based on a global value. Second, the assessments of operating cost savings and CO_2 savings are performed with different methods that use different time frames for analysis. The national operating cost savings is measured for the lifetime of residential boilers shipped in 2021–2050. Because CO_2 emissions have a very long residence time in the atmosphere,[g] the SCC values in future years reflect future CO_2 emissions impacts that continue beyond 2100.

Estimates of annualized benefits and costs of the adopted AFUE standards for residential boilers are shown in Table 1.2.3.

The results under the primary estimate are as follows. Using a 7-percent discount rate for benefits and costs other than CO_2 reduction (for which DOE used a 3-percent discount rate along with the SCC series that has a value of $40.0/t in 2015),[h] the estimated cost of the AFUE standards in this rule is $17.0 million per year in increased equipment costs, while the estimated annual benefits are $56.5 million in reduced equipment operating costs, $15.5 million in CO_2 reductions, and $12.3 million in reduced NO_X emissions. In this case, the net benefit amounts to $67.4 million per year. Using a 3-percent discount rate for all benefits and costs and the SCC series that has a value of $40.0/t in 2015, the estimated cost of the AFUE standards is $15.9 million per year in increased equipment costs, while the estimated annual benefits are $86.8 million in reduced operating costs, $15.5 million in CO_2 reductions, and $19.4 million in reduced NO_X emissions. In this case, the net benefit amounts to $105.8 million per year.

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f To convert the time-series of costs and benefits into annualized values, DOE calculated a present value in 2015, the year used for discounting the NPV of total consumer costs and savings. For the benefits, DOE calculated a present value associated with each year's shipments in the year in which the shipments occur (*e.g.*, 2021 or 2030), and then discounted the present value from each year to 2015. The calculation uses discount rates of 3 and 7 percent for all costs and benefits except for the value of CO2 reductions, for which DOE used case-specific discount rates, as shown in Table 1.2.2. Using the present value, DOE then calculated the fixed annual payment over a 30-year period, starting in the compliance year, that yields the same present value.

g The atmospheric lifetime of CO2 is estimated of the order of 30–95 years. Jacobson, MZ (2005), "Correction to 'Control of fossil-fuel particulate black carbon and organic matter, possibly the most effective method of slowing global warming,'" J. Geophys. Res. 110. pp. D14105.

h DOE used a 3-percent discount rate because the SCC values for the series used in the calculation were derived using a 3-percent discount rate (see chapter 14).

Table 1.2.3 Annualized Benefits and Costs of Amended AFUE Energy Conservation Standards for Residential Boilers (TSL 3)

	Discount Rate %	Primary Estimate*	Low Net Benefits Estimate*	High Net Benefits Estimate*
		million 2014$/year		
Benefits				
Consumer Operating Cost Savings	7	56.5	53.5	60.1
	3	86.8	81.6	92.8
CO_2 Reduction Value ($12.2/t case)**	5	4.4	4.3	4.5
CO_2 Reduction Value ($40.0/t case)**	3	15.5	15.3	15.8
CO_2 Reduction Value ($62.3/t case)**	2.5	23.0	22.7	23.4
CO_2 Reduction Value ($117/t case)**	3	47.5	46.8	48.3
NO_x Reduction Value†	7	12.3	12.2	28.0
	3	19.4	19.2	43.2
Total Benefits††	7 plus CO_2 range	73 to 116	70 to 112	93 to 136
	7	84.4	81.0	104.0
	3 plus CO_2 range	111 to 154	105 to 148	141 to 184
	3	121.7	116.1	151.9
Costs				
Consumer Incremental Installed Costs	7	17.0	19.9	14.7
	3	15.9	19.2	13.4
Net Benefits				
Total††	7 plus CO_2 range	56 to 99	50 to 93	78 to 122
	7	67.4	61.1	89.3
	3 plus CO_2 range	95 to 138	86 to 128	127 to 171
	3	105.8	96.9	138.5

* This table presents the annualized costs and benefits associated with residential boilers shipped in 2021−2050. These results include benefits to consumers which accrue after 2050 from the products purchased in 2021−2050. The results account for the incremental variable and fixed costs incurred by manufacturers due to the standard, some of which may be incurred in preparation for the rule. The Primary, Low Benefits, and High Benefits Estimates utilize projections of energy prices from the *AEO 2015* Reference case, Low Economic Growth case, and High Economic Growth case, respectively. In addition, incremental product costs reflect a medium decline rate in the Primary Estimate, a low decline rate in the Low Benefits Estimate, and a high decline rate in the High Benefits Estimate. The methods used to derive projected price trends are explained in chapter 8.
** The CO_2 values represent global monetized values of the SCC, in 2014$, in 2015 under several scenarios of the updated SCC values. The first three cases use the averages of SCC distributions calculated using 5%, 3%, and 2.5% discount rates, respectively. The fourth case represents the 95th percentile of the SCC distribution calculated using a 3% discount rate. The SCC time series incorporate an escalation factor.

† The $/ton values used for NO_X are described in chapter 14. DOE estimated the monetized value of NOx emissions reductions using benefit per ton estimates from the Regulatory Impact Analysis titled, "Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants," published in June 2014 by EPA's Office of Air Quality Planning and Standards. (Available at: http://www3.epa.gov/ttnecas1/regdata/RIAs/111dproposalRIAfinal0602.pdf.) For DOE's Primary Estimate and Low Net Benefits Estimate, the agency is presenting a national benefit-per-ton estimate for particulate matter emitted from the Electric Generating Unit sector based on an estimate of premature mortality derived from the ACS study (Krewski et al., 2009). For DOE's High Net Benefits Estimate, the benefit-per-ton estimates were based on the Six Cities study (Lepuele et al., 2011), which are nearly two-and-a-half times larger than those from the ACS study. Because of the sensitivity of the benefit-per-ton estimate to the geographical considerations of sources and receptors of emission, DOE intends to investigate refinements to the agency's current approach of one national estimate by assessing the regional approach taken by EPA's Regulatory Impact Analysis for the Clean Power Plan Final Rule.
†† Total benefits for both the 3% and 7% cases are derived using the series corresponding to the average SCC with the 3-percent discount rate ($40.0/t) case. In the rows labeled "7% plus CO_2 range" and "3% plus CO_2 range," the operating cost and NO_X benefits are calculated using the labeled discount rate, and those values are added to the full range of CO_2 values.

Estimates of annualized benefits and costs of the adopted standby mode and off mode standards are shown in Table 1.2.4. The results under the primary estimate are as follows. Using a 7-percent discount rate for benefits and costs other than CO_2 reduction (for which DOE used a 3-percent discount rate along with the SCC series that has a value of $40.0/t in 2015), the estimated cost of the residential boiler standby mode and off mode standards in this rule is $0.46 million per year in increased equipment costs, while the estimated annual benefits are $0.84 million in reduced equipment operating costs, $0.25 million in CO_2 reductions, and $0.03 million in reduced NO_X emissions. In this case, the net benefit amounts to $0.66 million per year. Using a 3-percent discount rate for all benefits and costs and the SCC series that has a value of $40.0/t in 2015, the estimated cost of the AFUE standards is $0.46 million per year in increased equipment costs, while the estimated annual benefits are $1.28 million in reduced operating costs, $0.25 million in CO_2 reductions, and $0.04 million in reduced NO_X emissions. In this case, the net benefit amounts to $1.11 million per year.

Table 1.2.4 Annualized Benefits and Costs of Adopted Standby Mode and Off Mode Energy Conservation Standards for Residential Boilers (TSL 3)

	Discount Rate %	Primary Estimate*	Low Net Benefits Estimate*	High Net Benefits Estimate*
		million 2014$/year		
Benefits				
Consumer Operating Cost Savings	7	0.84	0.81	0.89
	3	1.28	1.25	1.38
CO_2 Reduction Value ($12.2/t case)**	5	0.07	0.07	0.07
CO_2 Reduction Value ($40.0/t case)**	3	0.25	0.25	0.26
CO_2 Reduction Value ($62.3/t case)**	2.5	0.37	0.36	0.38
CO_2 Reduction Value ($117/t case)**	3	0.77	0.75	0.79
NO_x Reduction Value †	7	0.03	0.03	0.06
	3	0.04	0.04	0.10
Total Benefits††	7 plus CO_2 range	0.94 to 1.63	0.91 to 1.59	1.02 to 1.74
	7	1.12	1.09	1.21
	3 plus CO_2 range	1.40 to 2.09	1.36 to 2.04	1.54 to 2.26
	3	1.58	1.54	1.73
Costs				
Consumer Incremental Installed Costs	7	0.46	0.45	0.47
	3	0.46	0.45	0.47
Net Benefits				
Total††	7 plus CO_2 range	0.48 to 1.17	0.46 to 1.14	0.55 to 1.26
	7	0.66	0.63	0.73
	3 plus CO_2 range	0.93 to 1.63	0.91 to 1.59	1.07 to 1.78
	3	1.11	1.09	1.25

* This table presents the annualized costs and benefits associated with residential boilers shipped in 2021−2050. These results include benefits to consumers which accrue after 2050 from the products purchased in 2021−2050. The results account for the incremental variable and fixed costs incurred by manufacturers due to the standard, some of which may be incurred in preparation for the rule. The Primary, Low Benefits, and High Benefits Estimates utilize projections of energy prices from the *AEO 2015* Reference case, Low Economic Growth case, and High Economic Growth case, respectively.

** The CO_2 values represent global monetized values of the SCC, in 2014$, in 2015 under several scenarios of the updated SCC values. The first three cases use the averages of SCC distributions calculated using 5%, 3%, and 2.5% discount rates, respectively. The fourth case represents the 95th percentile of the SCC distribution calculated using a 3% discount rate. The SCC time series incorporate an escalation factor.

† The $/ton values used for NO_X are described in chapter 14. DOE estimated the monetized value of NOx emissions reductions using benefit per ton estimates from the Regulatory Impact Analysis titled, "Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants," published in June 2014 by EPA's Office of Air Quality Planning and Standards. (Available at: http://www3.epa.gov/ttnecas1/regdata/RIAs/111dproposalRIAfinal0602.pdf.) For DOE's Primary Estimate and Low Net Benefits Estimate, the agency is presenting a national benefit-per-ton estimate for particulate matter emitted from the Electric Generating Unit sector based on an estimate of premature mortality derived from the ACS study (Krewski et al., 2009). For DOE's High Net Benefits Estimate, the benefit-per-ton estimates were based on the Six Cities study (Lepuele et al., 2011), which are nearly two-and-a-half times larger than those from the ACS study. Because of the sensitivity of the benefit-per-ton estimate to the geographical considerations of sources and receptors of emission, DOE intends to investigate refinements to the agency's current approach of one national estimate by assessing the regional approach taken by EPA's Regulatory Impact Analysis for the Clean Power Plan Final Rule.
†† Total benefits for both the 3% and 7% cases are derived using the series corresponding to the average SCC with the 3-percent discount rate ($40.0/t) case. In the rows labeled "7% plus CO_2 range" and "3% plus CO_2 range," the operating cost and NO_X benefits are calculated using the labeled discount rate, and those values are added to the full range of CO_2 values.

DOE's analysis of the national impacts of the adopted standards is described in chapters 10, 13, and 14 of this TSD.

Based on the analyses culminating in this final rule, DOE found the benefits to the Nation of the standards (energy savings, positive NPV of consumer benefits, consumer LCC savings, and emission reductions) for both AFUE as well as standby mode and off would outweigh the burdens (loss of INPV for manufacturers and LCC increases for some consumers). DOE has concluded that the standards in this final rule represent the maximum improvement in energy efficiency that is technologically feasible and economically justified, and would result in significant conservation of energy.

DOE also added the annualized benefits and costs from the individual annualized tables to provide a combined benefit and cost estimate of the adopted AFUE and standby mode and off mode standards, as shown in Table 1.2.5.[i] The results under the primary estimate are as follows. Using a 7-percent discount rate for benefits and costs other than CO_2 reduction (for which DOE used a 3-percent discount rate along with the SCC series that has a value of $40.0/t in 2015), the estimated cost of the residential boiler AFUE and standby mode and off mode standards in this rule is $17.4 million per year in increased equipment costs, while the estimated annual benefits are $57.4 million in reduced equipment operating costs, $15.8 million in CO_2 reductions, and $12.4 million in reduced NO_X emissions. In this case, the net benefit amounts to $68.1 million per year. Using a 3-percent discount rate for all benefits and costs and the SCC series that has a value of $40.0/t in 2015, the estimated cost of the residential boiler AFUE and standby mode and off mode standards in this rule is $16.4 million per year in increased equipment costs, while the estimated annual benefits are $88.1 million in reduced equipment operating costs, $15.8 million in CO_2 reductions, and $19.4 million in reduced NO_X emissions. In this case, the net benefit amounts to $106.9 million per year

i To obtain the combined results, DOE added the results for the AFUE standards in Table 1.2.3 with the results for the standby standards in Table 1.2.4.

Table 1.2.5 Annualized Benefits and Costs of Adopted AFUE and Standby Mode and Off Mode Energy Conservation Standards for Residential Boilers (TSL 3)

	Discount Rate	Primary Estimate*	Low Net Benefits Estimate*	High Net Benefits Estimate*
		million 2014$/year		
Benefits				
Consumer Operating Cost Savings	7%	57.4	54.3	61.0
	3%	88.1	82.8	94.2
CO_2 Reduction Value ($12.2/t case)**	5%	4.5	4.4	4.6
CO_2 Reduction Value ($40.0/t case)**	3%	15.8	15.6	16.1
CO_2 Reduction Value ($62.3/t case)**	2.5%	23.4	23.0	23.8
CO_2 Reduction Value ($117/t case)**	3%	48.2	47.5	49.1
NO_X Reduction Value†	7%	12.4	12.2	28.0
	3%	19.4	19.2	43.3
Total Benefits††	7% plus CO_2 range	74.2 to 117.9	70.9 to 114	93.6 to 138
	7%	85.5	82.1	105
	3% plus CO_2 range	112 to 156	106 to 150	142 to 187
	3%	123.3	117.6	153.6
Costs				
Consumer Incremental Product Costs	7%	17.4	20.3	15.1
	3%	16.4	19.6	13.9
Net Benefits				
Total††	7% plus CO_2 range	56.8 to 100	50.6 to 93.7	78.5 to 123
	7%	68.1	61.8	90.0
	3% plus CO_2 range	95.6 to 139	86.8 to 130	128 to 173
	3%	106.9	98.0	139.7

* This table presents the annualized costs and benefits associated with residential boilers shipped in 2021−2050. These results include benefits to consumers which accrue after 2050 from the products purchased in 2021−2050. The results account for the incremental variable and fixed costs incurred by manufacturers due to the standard, some of which may be incurred in preparation for the rule. The Primary, Low Benefits, and High Benefits Estimates utilize projections of energy prices from the *AEO 2015* Reference case, Low Economic Growth case, and High Economic Growth case, respectively. In addition, incremental product costs reflect a medium decline rate in the Primary Estimate, a low decline rate in the Low Benefits Estimate, and a high decline rate in the High Benefits Estimate. The methods used to derive projected price trends are explained in chapter 8.
** The CO_2 values represent global monetized values of the SCC, in 2014$, in 2015 under several scenarios of the updated SCC values. The first three cases use the averages of SCC distributions calculated using 5%, 3%, and 2.5% discount rates, respectively. The fourth case represents the 95th percentile of the SCC distribution calculated using a 3% discount rate. The SCC time series incorporate an escalation factor.
† The $/ton values used for NO_X are described in chapter 14. DOE estimated the monetized value of NO_X emissions reductions using benefit per ton estimates from the Regulatory Impact Analysis titled, "Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants," published in June 2014 by EPA's Office of Air Quality Planning and Standards. (Available at: http://www3.epa.gov/ttnecas1/regdata/RIAs/111dproposalRIAfinal0602.pdf.) For DOE's Primary Estimate and Low Net Benefits Estimate, the agency is presenting a national benefit-per-ton estimate for particulate matter emitted from the Electric Generating Unit sector based on an estimate of premature mortality derived from the ACS study (Krewski et al., 2009). For DOE's High Net Benefits Estimate, the benefit-per-ton estimates were based on the Six Cities study (Lepuele et al., 2011), which are nearly two-and-a-half times larger than those from the ACS study. Because of the sensitivity of the benefit-per-ton estimate to the geographical considerations of sources and receptors of emission, DOE intends to investigate refinements to the agency's current approach of one national estimate by assessing the regional approach taken by EPA's Regulatory Impact Analysis for the Clean Power Plan Final Rule.
†† Total benefits for both the 3% and 7% cases are derived using the series corresponding to the average SCC with the 3-percent discount rate ($40.0/t) case. In the rows labeled "7% plus CO_2 range" and "3% plus CO_2 range," the operating cost and NO_X benefits are calculated using the labeled discount rate, and those values are added to the full range of CO_2 values.

1.3 OVERVIEW OF STANDARDS FOR RESIDENTIAL BOILERS

Title III, Part B[j] of EPCA (42 U.S.C. 6291-6309, as codified), sets forth a variety of provisions designed to improve energy efficiency and established the Energy Conservation Program for Consumer Products Other Than Automobiles, a program covering most major household appliances and certain industrial and commercial equipment.[k] The National Appliance Energy Conservation Act of 1987 (NAECA), Pub. L. 100-12, amended EPCA to establish energy conservation standards for residential furnaces and boilers, as well as requirements to conduct two cycles of rulemaking to determine whether these standards should be amended. (42 U.S.C. 6295(f))

On November 19, 2007, DOE published a final rule revising the energy conservation standards for residential furnaces and boilers, which addressed the first required review of standards for boilers under 42 U.S.C. 6295(f)(4)(B). 72 FR 65136. On December 19, 2007, the Energy Independence and Security Act of 2007 (EISA 2007), Pub. L. No. 110-140, was signed into law, which further revised the energy conservation standards for residential boilers. More specifically, EISA 2007 revised the minimum AFUE requirements for residential

j For editorial reasons, upon codification in the U.S. Code, Part B was redesignated Part A.
k All references to EPCA in this document refer to the statute as amended through the American Energy Manufacturing Technical Corrections Act (AEMTCA), Pub. L. 112-210 (Dec. 18, 2012).

boilers and set several design requirements for each product class (42 U.S.C. 6295(f)(3)). EISA 2007 required compliance with the amended energy conservation standards for residential boilers beginning on September 1, 2012.

On July 28, 2008, DOE published a final rule technical amendment to the November 2007 furnaces and boilers final rule to codify the energy conservation standard levels, the design requirements, and compliance dates for residential boilers outlined EISA 2007. 73 FR 43611. For gas-fired hot water boilers, oil-fired hot water boilers, and electric hot water boilers, EISA 2007 mandates, among other requirements, that residential boilers manufactured after September 2012 have an automatic means for adjusting water temperature. 10 CFR 430.32(e)(2)(ii)-(iv). The automatic means for adjusting water temperature must automatically adjust the water temperature of the water supplied by the boiler to ensure that an incremental change in the inferred heat load produces a corresponding incremental change in the temperature of the water supplied. EISA 2007 also disallows the use of constant-burning pilot lights in gas-fired hot water boilers and gas-fired steam boilers.

1.4 PROCESS FOR SETTING ENERGY CONSERVATION STANDARDS

Under EPCA, when DOE is studying new or amended standards, it must consider, to the greatest extent practicable, the following seven factors (42 U.S.C. 6295 (o)(2)(B)(i)):

1) the economic impact of the standard on the manufacturers and consumers of the affected products;

2) the savings in operating costs throughout the estimated average life of the product compared to any increases in the initial cost or maintenance expense;

3) the total projected amount of energy savings likely to result directly from the imposition of the standard;

4) any lessening of the utility or the performance of the products likely to result from the imposition of the standard;

5) the impact of any lessening of competition, as determined in writing by the Attorney General, that is likely to result from the imposition of the standard;

6) the need for national energy conservation; and

7) other factors the Secretary considers relevant.

Other statutory requirements are set forth in 42 U.S.C. 6295 (o)(1)–(2)(A), (2)(B)(ii)–(iii), and (3)–(4) and 42 U.S.C. 6316(e).

DOE considers interested party participation to be a very important part of the process for setting energy conservation standards. Through formal public notifications (*i.e.*,

Federal Register notices), DOE actively encourages the participation and interaction of all interested parties during the comment period in each stage of the rulemaking. Beginning with the framework document and during subsequent comment periods, interactions among interested parties provide a balanced discussion of the information that is required for the standards rulemaking.

Before DOE determines whether to adopt a proposed energy conservation standard, it must first solicit comments on the proposed standard. (42 U.S.C. 6295(p)(2)) Any new or amended standard must be designed to achieve the maximum improvement in energy efficiency and be technologically feasible and economically justified. (42 U.S.C. 6295(o)(2)(A)) To determine whether economic justification exists, DOE must review comments on the proposal and determine that the benefits of the proposed standard exceed its burdens to the greatest extent practicable, weighing the seven factors listed above. (42 U.S.C. 6295 (o)(2)(B)(i))

After the publication of the framework document, this energy conservation standards rulemaking process involves three additional, formal public notices, which DOE publishes in the *Federal Register*. The first of the rulemaking notices is a notice of data availability (NODA), which is designed to publicly vet the models and tools used in the rulemaking and to facilitate public participation before the notice of proposed rulemaking (NOPR) stage. The second notice is the NOPR, which presents a discussion of: (1) comments received in response to the NODA analyses; (2) analyses of the impacts of potential amended energy conservation standards on consumers, manufacturers, and the Nation; (3) DOE's weighting of these impacts of amended energy conservation standards; and (4) the proposed energy conservation standards for each product. The third notice is the final rule, which presents a discussion of: (1) the comments received in response to the NOPR; (2) the revised analyses; (3) DOE's weighting of these impacts; (4) the amended energy conservation standards DOE is adopting for each product; and (5) the effective dates of the amended energy conservation standards.

On February 11, 2013, DOE published a notice of public meeting and availability of the framework document. 78 FR 9631. The framework document, *Rulemaking Framework Document for Residential Boilers*, describes the procedural and analytical approaches DOE anticipated using to evaluate the establishment of amended energy conservation standards for these products. This document is available at: www.regulations.gov/#!documentDetail;D=EERE-2012-BT-STD-0047-0001.

After publishing the framework document, DOE held a public meeting on March 13, 2013 to discuss procedural and analytical approaches to the rulemaking. In addition, DOE used the public meeting to inform and facilitate involvement of interested parties in the rulemaking process. The analytical framework presented at the public meeting described the different analyses, such as the engineering analysis and the consumer economic analyses (*i.e.*, the LCC and payback period (PBB) analyses), the methods proposed for conducting them, and the relationships among the various analyses.

Table 1.4.1 Analyses Under the Process Rule

NODA	NOPR	Final Rule
Market and technology assessment	Revised analyses	Revised NOPR analyses
Screening analysis	Life-cycle cost subgroup analysis	
Engineering analysis	Manufacturer impact analysis	
Energy use determination	Utility impact analysis	
Markups for equipment price determination	Emissions analysis	
Life-cycle cost and payback period analyses	Employment impact analysis	
Shipments analysis	Regulatory impact analysis	
National impact analysis		

On February 11, 2014, DOE published a NODA and TSD. 79 FR 8122. The NODA TSD provided technical analyses and results that support the information presented in the NODA for residential boilers. The NODA TSD also provided responses to the comments submitted from interested parties during the framework document comment period. The document is available at: www.regulations.gov/#!documentDetail;D=EERE-2012-BT-STD-0047-0015. The comment period was closed on March 13, 2014.

On March 31, 2015, DOE published a notice of proposed rulemaking in the Federal Register (March 2015 NOPR). 80 FR 17222. In the March 2015 NOPR, DOE addressed in detail the comments received in earlier stages of the rulemaking, and proposed amended energy conservation standards for residential boilers. In conjunction with the March 2015 NOPR, DOE published on its website the complete NOPR TSD, which incorporated the analysis DOE conducted and technical documentation for each analysis. Also published on DOE's website were the LCC analysis spreadsheet and the national impact analysis spreadsheet. These materials are available at:
www1.eere.energy.gov/buildings/appliance_standards/product.aspx?productid=89

The comment period for the March 2015 NOPR was initially set to end June 1, 2015, but was subsequently extended to July 1, 2015 in a *Federal Register* notice published on May 20, 2015. After the publication of the March 2015 NOPR, DOE received written comments. DOE also held a public meeting in Washington DC on April 30, 2015 to discuss and receive comments regarding the tools and methods DOE used in the NOPR analysis, as well as the results for that analysis.

In addition to revising the various NOPR analyses, DOE also performed an LCC subgroup analysis, manufacturer impact analysis, utility impact analysis, employment impact analysis, and regulatory impact analysis for the final Rule.

1.5 STRUCTURE OF THE DOCUMENT

This document outlines the analytical approaches used in this rulemaking. This document consists of 17 chapters and 24 appendices.

Chapter 1	Introduction: provides an overview of this rulemaking and outlines the structure of the document.
Chapter 2	Analytical Framework: describes an overview of the rulemaking process, methodology, analytical tools, and relationships among the various analyses.
Chapter 3	Market and Technology Assessment: characterizes the market for the considered products and the technologies available for increasing product efficiency.
Chapter 4	Screening Analysis: identifies all the design options that improve efficiency of the considered products and determines which technology options are viable for consideration in the engineering analysis.
Chapter 5	Engineering Analysis: discusses the methods used for developing the relationship between manufacturer production cost and increased product efficiency.
Chapter 6	Markups Analysis: discusses the methods used for establishing markups for converting manufacturer prices to customer product costs.
Chapter 7	Energy Use Analysis: discusses the process used for generating energy-use estimates for the considered products as a function of standard levels.
Chapter 8	Life-Cycle Cost and Payback Period Analyses: discusses the methods used to analyze effects of standards on individual customers and users of the products and compares the life-cycle cost (LCC) and payback period (PBP) of products with and without higher energy conservation standards.
Chapter 9	Shipments Analysis: estimates shipments of the products over the 30-year analysis period that is used in performing the national impact analysis (NIA), including how shipments may vary under alternative standard levels.
Chapter 10	National Impact Analysis: assesses the national energy savings, and the national net present value of total consumer costs and savings, expected to result from specific, potential energy conservation standards.

Chapter 11	Consumer Subgroup Analysis: discusses the effects of standards on subgroups of residential boiler consumers and compares the LCC and PBP of products with and without higher energy conservation standards for these consumers.
Chapter 12	Manufacturer Impact Analysis: discusses the effects of amended standards on the finances and profitability of manufacturers.
Chapter 13	Emissions Impact Analysis: discusses the effects of standards on air-borne emissions, including the impact of emissions of six pollutants or greenhouse gases: sulfur dioxide, (SO_2), nitrogen oxides, (NO_X), carbon dioxide, (CO_2), mercury, (Hg), methane, (CH_4), and nitrous oxide. (N_2O).
Chapter 14	Monetization of Emission Reductions Benefits: discusses the monetization of reductions in CO_2 and NO_X emissions.
Chapter 15	Utility Impact Analysis: discusses the effects of standards on the installed generation capacity of electric utilities.
Chapter 16	Employment Impact Analysis: discusses the effects of standards on national employment.
Chapter 17	Regulatory Impact Analysis: discusses the present regulatory actions as well as the impact of non-regulatory alternatives to setting energy efficiency standards.
Appendix 6A	Detailed Data for Product Price Markups
Appendix 6B	Incremental Markups: Theory and Evidence
Appendix 7A	Building Variables
Appendix 7B	Determination of Residential Boiler Energy Use in the LCC Analysis
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Appendix 8B	Uncertainty and Variability in the LCC Analysis for Residential Boilers

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Appendix 8D	Energy Price Calculations for Residential Boilers
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CHAPTER 2. ANALYTICAL FRAMEWORK

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CHAPTER 2. ANALYTICAL FRAMEWORK

2.1 INTRODUCTION

The Energy Policy and Conservation Act (EPCA), as amended (42 USC 6291 *et. seq.*), requires that when prescribing new or amended energy conservation standards for covered products, the U.S. Department of Energy (DOE) must promulgate standards that achieve the maximum improvements in energy efficiency that are technologically feasible and economically justified. (42 U.S.C. 6295(o)(2)(A)) This chapter provides a description of the analytical framework that DOE is using to evaluate amended energy conservation standards for residential boilers. This chapter sets forth the methodology, analytical tools, and relationships among the various analyses that are part of this rulemaking.

Figure 2.1.1 summarizes the analytical components of the standards-setting process. The focus of this figure is the center column, identified as "Analyses." The columns labeled "Key Inputs" and "Key Outputs" show how the analyses fit into the rulemaking process, and how the analyses relate to each other. Key inputs are the types of data and information that the analyses require. Some key inputs exist in public databases; DOE collects other inputs from interested parties or those with special knowledge. Key outputs are analytical results that feed directly into the standards-setting process. Arrows connecting analyses show types of information that feed from one analysis to another.

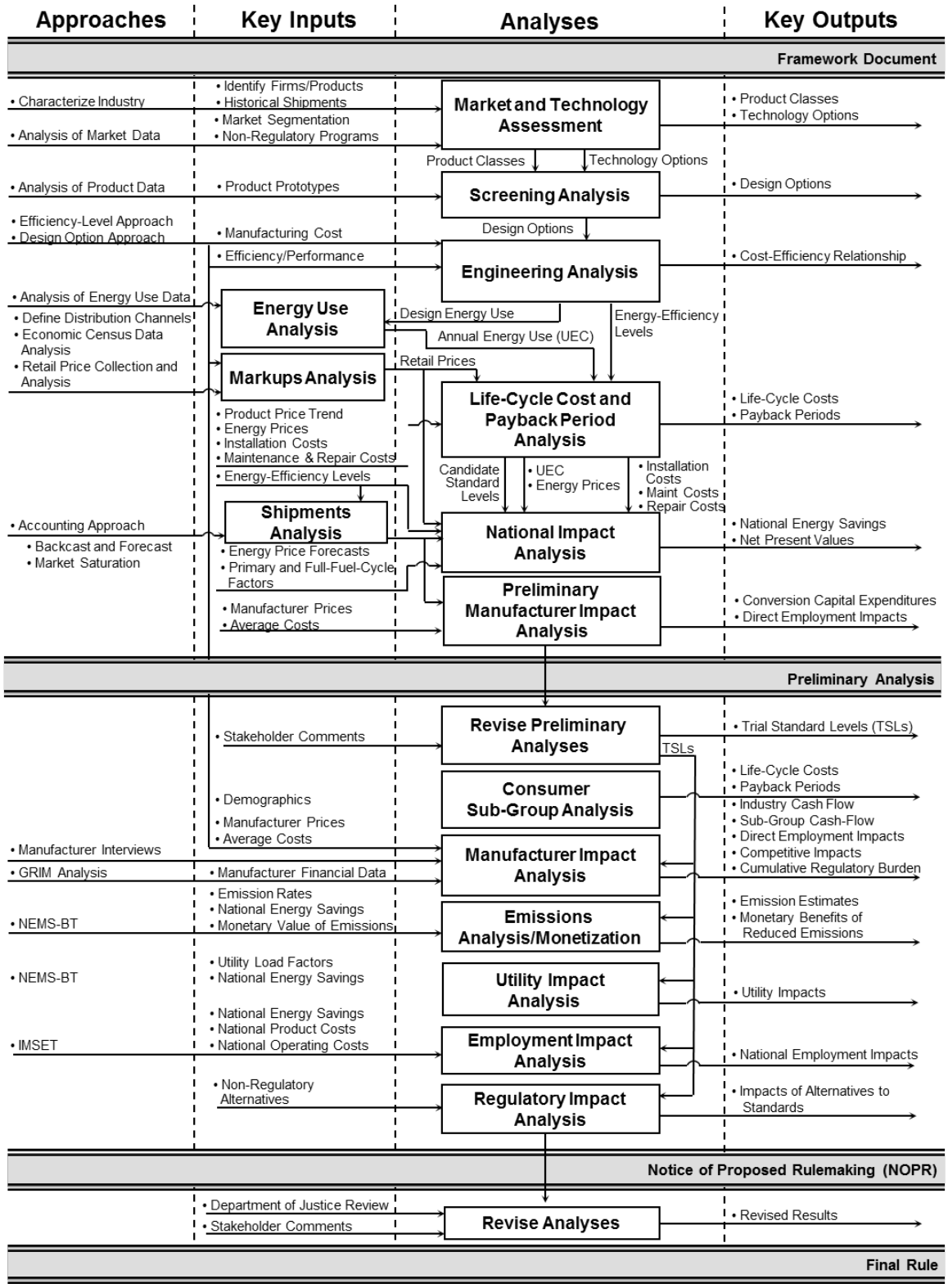

Figure 2.1.1 Flow Diagram of Analyses for the Rulemaking Process[a]

In developing its final rule, DOE used the results of the above analyses as a starting point, incorporating revisions to the analyses based on comments and new information received in response to the March 2015 NOPR. In this technical support document (TSD), DOE presents results of the following analyses that were performed for this final rule:

- A market and technology assessment to characterize the relevant products, their markets, and technology options for improving their energy efficiency, including prototype designs.
- A screening analysis to review each technology option and determine if it is technologically feasible; is practicable to manufacture, install, and service; would adversely affect product utility or product availability; or would have adverse impacts on health and safety.
- An engineering analysis to develop relationships between the manufacturer selling price (MSP) and increased efficiency.
- A markups analysis to develop distribution channel markups that relate the manufacturer production cost (MPC) to the cost to the consumer.
- An energy use analysis to determine the annual energy use of the considered products in a representative set of users.
- A life-cycle cost (LCC) and payback period (PBP) analysis to calculate the savings in operating costs at the consumer level throughout the life of the covered products compared with any increase in the installed cost for the products likely to result directly from imposition of a standard.
- A shipments analysis to forecast product shipments, which are then used to calculate the national impacts of standards on energy, net present value (NPV), and future manufacturer cash flows.
- A national impact analysis (NIA) to assess the aggregate impacts at the national level of potential energy conservation standards for the considered products, as measured by the NPV of total consumer economic impacts and the national energy savings (NES).
- An LCC subgroup analysis to evaluate variations in consumer characteristics that might cause a standard to disproportionately affect particular consumer subpopulations.
- A manufacturer impact analysis to assess the potential impacts of energy conservation standards on manufacturers' capital conversion expenditures, marketing costs, shipments, and research and development costs.

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[a] Note: This rulemaking issued a notice of data availability (NODA) instead of a preliminary analysis.

- A utility impact analysis to estimate the effects of potential standards on electric, gas, or oil utilities.
- An employment impact analysis to assess the aggregate impacts on national employment.
- An emissions analysis to assess the impacts of amended energy conservation standards on the environment.
- An emissions monetization to assess the benefits associated with emissions reductions.
- A regulatory impact analysis to examine major alternatives to amended energy conservation standards that potentially could achieve substantially the same regulatory goal at a lower cost.

2.2 BACKGROUND

Amendments to Title III of EPCA have given DOE the authority to regulate the energy efficiency of several products, including residential boilers, which are the focus of this document. (42 U.S.C. 6292(a)(5); 42 U.S.C. 6295(f)(4)(C))

DOE developed this analytical framework and documented its findings in the *Rulemaking Framework Document for Residential Boilers* (February 11, 2013). On that same day, DOE published the notice of public meeting and availability of the framework document for residential boilers in the *Federal Register*. 78 FR 9631. In conjunction, DOE posted the framework document to the DOE website.[b] DOE presented the analytical approach to interested parties during a public meeting held on March 13, 2013. DOE responded to comments from interested parties in the notice of data availability (NODA), which was published on February 11, 2014. 79 FR 8122. In response to the publication of the NODA, DOE received comments from interested parties regarding DOE's analytical approach. DOE published the notice of proposed rulemaking on March 31, 2015. 80 FR 28852. DOE subsequently held a public meeting on April 30, 2015 to discuss and receive comments regarding the tools and method used in the NOPR analysis.

The following sections provide a general description of the different analytical components of the rulemaking analytical framework. DOE used the most reliable and accurate data available at the time of each analysis in this rulemaking.

2.3 MARKET AND TECHNOLOGY ASSESSMENT

When DOE begins an energy conservation standards rulemaking, it develops information that provides an overall picture of the market for the products considered, including the nature of

[b] The February 11, 2013, residential boilers framework document is available at the following link: www1.eere.energy.gov/buildings/appliance_standards/rulemaking.aspx?ruleid=112.

the products, market characteristics, and industry structure. This activity consists of both quantitative and qualitative efforts based primarily on publicly available information. The market assessment examined manufacturers, trade associations, and the quantities and types of products offered for sale.

DOE recognizes that there may be limited public information on national shipments, manufacturing costs, channels of distribution, and manufacturer market shares of residential boilers. This type of data is an important input for analyses that determine if energy conservation standards are economically justified and will result in significant energy savings. Therefore, DOE encourages interested parties to submit data that will improve DOE's understanding of the residential boilers market. These data may be provided under a confidentiality agreement with DOE's contractor responsible for this part of the rulemaking analysis, Navigant Consulting, Inc. (NCI). As in other rulemakings, NCI works with confidential data provided by manufacturers and other organizations in preparing aggregated results for DOE's analysis. These aggregated results do not divulge the sensitive, individual raw data, but enable other interested parties to comment on the aggregated dataset.

Alternatively, interested parties may submit confidential data to DOE, indicating in writing which data should remain confidential. Interested parties must submit confidential information to DOE according to the procedures outlined in 10 CFR 1004.11. Pursuant to 10 CFR 1004.11, any person submitting information that he or she believes to be confidential and exempt by law from public disclosure should submit two copies. One copy of the document shall include all the information believed to be confidential, and the other copy shall have the information believed to be confidential deleted. DOE will make its own determination about the confidential status of the information and treat it accordingly.[c]

DOE reviewed relevant literature and interviewed manufacturers to develop an overall picture of the residential boiler industry in the United States. Industry publications and trade journals, government agencies, and trade organizations provided the bulk of the information, including: (1) manufacturers and their approximate market shares; (2) shipments by product type (*e.g.*, gas-fired hot water, oil-fired hot water); (3) product information; and (4) industry trends.

The analyses developed as part of the market and technology assessment are described in chapter 3.

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[c] Factors that DOE considers when evaluating requests to treat submitted information as confidential include: (1) a description of the items; (2) whether and why such items are customarily treated as confidential within the industry; (3) whether the information is generally known by or available from other public sources; (4) whether the information has previously been made available to others without obligation concerning its confidentiality; (5) an explanation of the competitive injury to the submitting person which would result from public disclosure; (6) a date after which such information might lose its confidential character; and (7) why disclosure of the information would be contrary to the public interest.

2.3.1 Scope of Coverage

For this rulemaking, DOE proposes to maintain the scope of coverage as defined by its current regulations for this analysis of amended annual fuel utilization efficiency (AFUE) standards, which includes six product classes of residential boilers. DOE has not conducted an analysis of an AFUE standard level for electric boilers or combination appliances. However, DOE has considered standby mode and off-mode standards for electric boilers.

2.3.2 Product Classes

When evaluating and establishing energy conservation standards, DOE generally divides covered products into product classes by the type of energy used, capacity, or other performance-related features that affect efficiency. Different energy conservation standards may apply to different product classes. (42 U.S.C. 6295(q)) DOE then conducts its analysis for each product class and considers establishing standards that provide separate standard levels for each product class considered.

In the NOPR and final rule analysis, DOE maintained the existing product classes for residential boilers, which are denominated in EPCA at 42 U.S.C. 6295(f)(3)(A) and at 10 CFR 430.32(e)(2)(ii).[d] For residential boilers, the existing product classes are based on fuel type and heat transfer medium. The type of energy used is explicitly identified as a criterion for creating a separate product class in EPCA. (42 U.S.C. 6295(q)) Further, DOE has determined that heat transfer medium is a performance-related characteristic that merits a separate product class due to the significantly different efficiency and performance characteristics of hot water and steam boilers. In this analysis, DOE maintained the product classes established by EPCA, and analyzed six product classes for this rulemaking, which are shown in Table 2.3.1. For gas-fired and oil-fired boilers, enough public data were readily available to conduct robust analyses, and DOE analyzed amended AFUE standards. The electric boiler product classes represent significantly fewer shipments and significantly less energy use. Further, according to DOE's test procedure, electric boilers are assigned an AFUE rating of 100 percent, and therefore there are no design options available for improving the AFUE of these products. DOE analyzed only standby mode and off mode electrical use for the electric boilers product classes.

[d] EPCA includes a total of six product classes, which includes a product class for electric steam boilers. EPCA specifies the minimum AFUE and the design requirements as "none." (42 U.S.C. 6295 (f)(3)(A)) Because there are no standards for electric steam boilers, this product class is not listed at 10 CFR 430.32(e)(2)(ii). However, DOE plans to maintain the electric steam boiler product class as specified by EPCA for consideration of standby mode and off mode energy conservation standards.

Table 2.3.1 Product Classes

Fuel Type	Heat Transfer Medium
Gas	Steam
	Hot Water
Oil	Steam
	Hot Water
Electric	Steam
	Hot Water

2.3.3 Market Assessment

As part of the market and technology assessment, DOE developed information that provides an overall picture of the market for the products considered, including the nature of the products, market characteristics, and industry structure. DOE collected quantitative and qualitative information, primarily from publicly available sources. The market assessment examined manufacturers, trade associations, and the quantities and types of products sold and offered for sale. DOE reviewed relevant literature and interviewed manufacturers to develop an overall picture of the residential boiler industry in the United States. Industry publications and trade journals, government agencies, and trade organizations provided the bulk of the information, including: (1) manufacturers and their market shares; (2) shipments by product type; (3) product information; and (4) industry trends. The analyses developed as part of the market assessment are described in chapter 3.

2.3.4 Technology Assessment

DOE typically uses information relating to existing and past technology options and prototype designs as inputs to determine what technologies manufacturers use to attain higher performance levels. In consultation with stakeholders, DOE develops a list of technologies for consideration. Initially, these technologies encompass all those DOE believes are technologically feasible.

DOE developed its list of technologically feasible design options for the considered products through consultation with manufacturers of components and systems, and from trade publications and technical papers. Because many options for improving product efficiency are available in existing units, product literature and direct examination provided additional information. The technologies examined in the technology assessment are described in detail in chapter 3 of the TSD.

2.4 SCREENING ANALYSIS

The purpose of the screening analysis is to evaluate the technologies identified in the technology assessment to determine which technologies to consider further and which technologies to screen out. DOE consulted with industry, technical experts, and other interested parties in developing a list of energy-saving technologies for the technology assessment. DOE

then applied the screening criteria to determine which technologies were unsuitable for further consideration in this rulemaking. Chapter 4, the screening analysis, contains details about DOE's screening criteria.

As presented in further detail below, the screening analysis examines whether various technologies: (1) are technologically feasible; (2) are practicable to manufacture, install, and service; (3) have an adverse impact on product utility or availability; and (4) have adverse impacts on health and safety. In consultation with interested parties, DOE reviewed the list of residential boiler technologies according to these criteria. In the engineering analysis, DOE further considers the efficiency-enhancement technologies that it did not eliminate in the screening analysis.

1. *Technological feasibility.* DOE screens out technologies that are not incorporated in commercially-available products or working prototypes.

2. *Practicability to manufacture, install, and service.* If DOE determines that mass production of a technology in commercial products and reliable installation and servicing of the technology cannot be achieved on the scale necessary to serve the relevant market by the time of the compliance date of the standard, it will not consider that technology further.

3. *Adverse impacts on product or product utility or availability.* If DOE determines a technology has a significant adverse impact on the utility of the product for significant consumer subgroups or results in the unavailability of any covered product type with performance characteristics (including reliability), features, size, capacities, and volumes that are substantially the same as products generally available in the United States at the time, it will not consider that technology further.

4. *Adverse impacts on health or safety.* If DOE determines that a technology will have significant adverse impacts on health or safety, it will not consider that technology further.

DOE develops an initial list of technology options from the technologies identified as technologically feasible in the technology assessment. Then, in consultation with interested parties, DOE reviews the list to determine if these options are practicable to manufacture, install, and service, would adversely affect product utility or availability, or would have adverse impacts on health and safety. In the engineering analysis, DOE further considers technology options that it did not screen out in the screening analysis. Chapter 4 contains additional details about the screening analysis and the justification for screening out certain technologies. In addition, chapter 5 contains a description of the technologies considered at each efficiency level.

2.5 ENGINEERING ANALYSIS

The engineering analysis (chapter 5) establishes the relationship between manufacturing production cost and selling price and efficiency for each residential boiler. This relationship

serves as the basis for cost-benefit calculations in terms of individual consumers, manufacturers, and the Nation. Chapter 5 discusses the product classes analyzed, representative baseline units, incremental efficiency levels, methodology used to develop manufacturing production costs and manufacturer markups, cost-efficiency curves, and the impact of efficiency improvements on the considered products. To determine the cost to consumers of residential boilers at various efficiency levels, DOE estimated manufacturing costs, markups in the distribution chain, installation costs, and maintenance costs.

In the engineering analysis pertaining to residential boilers, DOE evaluated a range of product efficiency levels and associated manufacturing costs. The purpose of the analysis is to estimate the incremental increase to selling prices that would result from increasing efficiency levels above the baseline model in each product class. The engineering analysis considers technologies not eliminated in the screening analysis, although certain technologies were not analyzed due to other reasons, such as negligible incremental efficiency improvements, lack of information on efficiency improvement, or the inability of the existing DOE test procedures to measure any reduction in energy use. DOE considers the remaining technologies, as appropriate, in developing the cost-efficiency curves, which are subsequently used for the LCC and PBP analyses.

DOE typically structures its engineering analysis around one of three methodologies: (1) the design option approach, which calculates the incremental costs of adding specific design options to a baseline model; (2) the efficiency level approach, which calculates the relative costs of achieving increases in energy efficiency levels without regard to the particular design options used to achieve such increases; and/or (3) the reverse engineering or cost-assessment approach, which involves a "bottom-up" manufacturing cost assessment based on a detailed bill of materials derived from tear-downs of the product being analyzed.

For this analysis, DOE conducted the engineering analysis for residential boilers using a combination of the efficiency level and cost-assessment approaches for analysis of various energy efficiency levels. More specifically, DOE identified the efficiency levels for analysis and then used the cost-assessment approach to determine the manufacturing costs at those levels. This approach involved physically disassembling commercially available products, consulting with outside experts, reviewing publicly available cost and performance information, and modeling product cost. Chapter 5 describes the methodology and results of the efficiency level analysis used to derive the cost-efficiency relationships.

2.6 MARKUPS ANALYSIS

DOE analyzed product markups to convert the manufacturer costs estimated in the engineering analysis to consumer prices, which then were used in the LCC and PBP and the manufacturer impact analyses. DOE calculated markups for baseline products (baseline markups) and for more efficient products (incremental markups). An incremental markup relates the change in the MPC of higher-efficiency models (the incremental cost increase) to the change in the retailer or distributor sales price.

To develop markups, DOE identified how the product is distributed from the manufacturer to the consumer. After establishing appropriate distribution channels, DOE used data from sources that included the financial filings of manufacturers and distributors to determine how prices are marked up as the product passes from the manufacturer to the consumer. Chapter 6 of the TSD provides details on DOE's development of markups for residential boilers.

2.7 ENERGY USE ANALYSIS

The energy use analysis assesses the energy savings potential from adopting higher efficiency standards for residential boilers. The analysis provides the basis for the energy savings values DOE uses in the LCC and subsequent analyses. DOE estimated the annual energy consumption of residential boilers at specified energy efficiency levels for a representative set of residential and commercial users of this product as defined by building type and location. The energy consumption estimates for residential boilers include the heating energy use by the product for space heating, as well as the auxiliary electricity consumption, such as pumps, the draft inducer, and the ignition device.

DOE used RECS 2009 and CBECS 2003 energy data and weather data from NOAA to estimate weather-normalized energy use. The RECS 2009 data provide information on the home characteristics, as well as heating energy use in each household. The survey includes household information such as the physical characteristics of housing units, household demographics, information about other heating and cooling products installed in the household, fuel types used, energy consumption and expenditures, and other relevant data. For residential boilers used in commercial applications, DOE used the CBECS 2003 buildings sample.

To estimate the annual energy consumption of boilers meeting higher efficiency levels, DOE calculated the heating load based on the RECS 2009 and CBECS 2003 estimates of the annual energy consumption of the boiler for each household. DOE then used the house heating load to determine the burner operating hours, which are needed to calculate the fuel consumption and electricity consumption based on the DOE residential furnace and boiler test procedure. To calculate the electricity consumption of the pump and other auxiliary components, DOE utilized data from manufacturer product literature.

In addition, when applicable, DOE accounted for energy use of boilers when used for domestic water heating during the summer and the impact of water heating during the non-heating season on electricity consumption of the air conditioner.

DOE also determined boiler electricity consumption during standby mode and off mode based on input from the engineering analysis (chapter 5).

Chapter 7 describes the details of the energy use analysis methodology.

2.8 LIFE-CYCLE COST AND PAYBACK PERIOD ANALYSIS

In determining whether an energy efficiency standard is economically justified, DOE considers the economic impacts of potential standards on consumers. The effects of new or amended standards on individual consumers usually include a reduction in operating cost and an increase in purchase cost. DOE used the following two metrics to measure consumer impacts.

- Life-cycle cost (LCC), the total consumer cost of a piece of product, generally throughout the life of the product. The LCC calculation includes total installed cost (manufacturer selling price, distribution markups, sales tax, and installation costs); operating costs (energy, repair, and maintenance costs); product lifetime; and a discount rate. Future operating costs are discounted to the time of purchase and summed over the lifetime of the product.
- Payback period (PBP), a measure of the amount of time it takes consumers to recover the assumed higher purchase price of more energy efficient product through reduced operating costs. Inputs to the calculation of payback period include the installed cost to the consumer and first-year operating costs.

DOE analyzed the net effect of amended residential boiler standards on consumers by determining the LCC and PBP using the engineering performance data, the energy use data, and the markups. Inputs to the LCC calculation include the installed cost to the consumer (purchase price plus installation cost), operating expenses (energy expenses, repair costs, and maintenance costs), the lifetime of the product, and a discount rate. Inputs to the payback period calculation include the installed cost to the consumer and first-year operating costs.

DOE generated LCC and PBP results as probability distributions using a simulation approach based on Monte Carlo analysis methods, in which certain key inputs to the analysis consist of probability distributions rather than single-point values. Therefore, the outcomes of the Monte Carlo analysis can also be expressed as probability distributions. As a result, the analysis produces a range of LCC and PBP results which allows DOE to identify the fraction of consumers achieving LCC savings or incurring net cost at the considered efficiency levels.

Chapter 8 provides more details on the LCC and PBP analysis methodology.

2.9 SHIPMENTS ANALYSIS

Forecasts of product shipments are needed to calculate the national impacts of standards on energy use, NPV, and future manufacturer cash flows. DOE developed shipment forecasts based on an analysis of key market drivers for residential boilers. In DOE's shipments model, shipments of product are driven by new construction, stock replacements, and other types of purchases.

The shipments models take an accounting approach, tracking market shares of each product class and the vintage of units in the existing stock. Stock accounting uses product

shipments as inputs to estimate the age distribution of in-service product stocks for all years. The age distribution of in-service product stocks is a key input to calculations of both the NES and NPV, because operating costs for any year depend on the age distribution of the stock.

For shipments of residential boilers replacing old products, DOE used a survival function to estimate the fraction of residential boilers of a given age still in operation. The survival function takes into account the product lifetime of residential boilers, as well as the fraction of consumers who choose to extend the life of their residential boiler by repairing rather than replacing the unit. Chapter 9 of this TSD provides additional details on the shipments analysis.

2.10 NATIONAL IMPACT ANALYSES

The national impact analysis assesses the net present value, to the nation, of total consumer life-cycle cost and net energy savings. DOE determined both the NPV and NES for the efficiency levels considered for the product classes analyzed. To make the analysis more accessible and transparent to all interested parties, DOE prepared a Microsoft® Excel spreadsheet model to forecast NES and the national consumer economic costs and savings resulting from new standards. The spreadsheet model uses as inputs typical values (as opposed to probability distributions). To assess the effect of input uncertainty on NES and NPV results, DOE may conduct sensitivity analyses by running scenarios on specific input variables. Chapter 10 of the NOPR TSD provides additional details regarding the national impact analysis.

Several of the inputs for determining NES and NPV depend on the forecast trends in product energy efficiency. For the no-new-standards case—without new or amended standards—DOE uses the efficiency distributions developed for the LCC analysis, and assumes some rate of change over the forecast period. In this analysis, DOE used a roll-up scenario in developing its forecasts of efficiency trends after standards take effect. Under a roll-up scenario, all products that perform at levels below a prospective standard are moved, or rolled-up, to the minimum performance level allowed under the standard. Product efficiencies above the standard level under consideration would remain the same as before the revised standard takes effect.

2.10.1 National Energy Savings Analysis

The inputs for determining the national energy savings for each product class are: (1) annual energy consumption per unit, (2) shipments, (3) product stock, (4) national energy consumption, and (5) site-to-source conversion factors for energy. DOE calculated national energy consumption by multiplying the number of units, or stock, of each product class (by vintage, or age) by the unit energy consumption (also by vintage). DOE calculated annual NES based on the difference in national energy consumption for the no-new-standards case and for each energy conservation standard being considered. DOE estimated energy consumption and savings based on site energy consumption, which it then converted to source energy. Cumulative energy savings are the sum of the NES for each year.

2.10.2 Net Present Value Analysis

The inputs for determining NPV are: (1) total annual installed cost, (2) total annual savings in operating costs, and (3) a discount factor to calculate the present value of costs and savings. DOE determined the net savings for each year as the difference between the no-new-standards case and each standards case in terms of total savings in operating costs versus total increases in installed costs. DOE calculated savings over the lifetime of product shipped in the forecast period. DOE calculated NPV as the difference between the present value of operating cost savings and the present value of total installed costs. DOE used a discount factor based on real discount rates of 3 and 7 percent to discount future costs and savings to present values.

For the NPV analysis, DOE calculates increases in total installed costs as the difference in total installed cost between the no-new-standards case and standards case (*i.e.*, once the standards take effect). Because the more efficient products bought in the standards case usually cost more than product bought in the no-new-standards case, cost increases appear as negative values in the NPV.

DOE expresses savings in operating costs as decreases associated with the lower energy consumption of products bought in the standards case compared to the no-new-standards case. Total savings in operating costs are the product of savings per unit and the number of units of each vintage that survive in a given year. DOE used *AEO 2015* as the source of projections for future energy prices.

DOE estimates the NPV of consumer benefits using both a 3-percent and a 7-percent real discount rate. DOE uses these discount rates in accordance with guidance provided by the Office of Management and Budget (OMB) to federal agencies on the development of regulatory analysis. (OMB Circular A-4 (Sept. 17, 2003), section E, "Identifying and Measuring Benefits and Costs".)

2.11 CONSUMER SUBGROUP ANALYSIS

In analyzing the potential impacts of new or amended standards on consumers, DOE evaluates the potential impact of new or amended standards on identifiable groups of consumers (*i.e.*, subgroups) that may be disproportionately affected by a national standard. Accordingly, DOE evaluated impacts on low-income households and senior-only households using the LCC and payback period spreadsheet model, using inputs appropriate to these subgroups to the extent possible. The residential boiler subgroup analysis is discussed in detail in chapter 11 of this TSD.

2.12 MANUACTURER IMPACT ANALYSIS

The manufacturer impact analysis (MIA) assesses the impacts of new or amended energy conservation standards on manufacturers of the considered equipment. Potential impacts include financial effects, both quantitative and qualitative, that might lead to changes in the manufacturing practices for these products. DOE identified these potential impacts through interviews with manufacturers and other interested parties.

DOE conducted the MIA in three phases. In Phase I, an industry profile was created to characterize the industry, and a preliminary MIA was conducted to identify important issues that required consideration. In Phase II, an industry cash flow model and an interview questionnaire were prepared to guide subsequent discussions. In Phase III, manufacturers were interviewed, and the impacts of standards were assessed both quantitatively and qualitatively. Industry and subgroup cash flow and NPV were assessed through use of the Government Regulatory Impact Model (GRIM). Then impacts on competition, manufacturing capacity, employment, and cumulative regulatory burden were assessed based on manufacturer interview feedback and discussions. DOE discusses its findings from the MIA in chapter 12 of this TSD.

2.13 EMISSIONS IMPACT ANALYSIS

In the emissions analysis, DOE estimated the impact on power sector emissions of carbon dioxide (CO_2), nitrogen oxides (NOx), sulfur dioxide (SO_2) and mercury (Hg) from potential energy conservation standards for the considered product. In addition, DOE estimated emissions impacts in production activities (extracting, processing, and transporting fuels) that provide the energy inputs to power plants. These are referred to as "upstream" emissions. Together, these emissions account for the full-fuel-cycle (FFC). In accordance with DOE's FFC Statement of Policy (76 FR 51282 (Aug. 18, 2011)), the FFC analysis includes impacts on emissions of methane and nitrous oxide, both of which are recognized as greenhouse gases.

Because the on-site operation of residential boilers requires use of fossil fuels and results in emissions of CO_2, NOx, and SO_2 at the sites where these appliances are used, DOE also accounted for the reduction in these site emissions and the associated upstream emissions due to potential standards.

DOE primarily conducted the emissions analysis using emissions factors for CO_2 and most of the other gases derived from data in the latest version of EIA's *AEO*. Combustion emissions of methane (CH_4) and nitrous oxide (N_2O) were estimated using emissions intensity factors published by the Environmental Protection Agency (EPA), GHG Emissions Factors Hub.[e]

EIA prepares the *AEO* using the National Energy Modeling System (NEMS). Each annual version of NEMS incorporates the projected impacts of existing air quality regulations on emissions. The text below refers to *AEO 2015,* which generally represents current legislation and environmental regulations, including recent government actions, for which implementing regulations were available as of October 31, 2014.

[e] www2.epa.gov/climateleadership/center-corporate-climate-leadership-ghg-emission-factors-hub

Sulfur dioxide emissions from affected electric generating units (EGUs) are subject to nationwide and regional emissions cap and trading programs. Title IV of the Clean Air Act sets an annual emissions cap on SO_2 for affected EGUs in the 48 contiguous states and the District of Columbia (D.C.). Sulfur dioxide emissions from 28 eastern states and D.C. were also limited under the Clean Air Interstate Rule (CAIR), which created an allowance-based trading program that operates along with the Title IV program in those states and D.C. 70 FR 25162 (May 12, 2005). CAIR was remanded to EPA by the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit), but it remained in effect.[f] On July 6, 2011 EPA issued a replacement for CAIR, the Cross-State Air Pollution Rule (CSAPR). 76 FR 48208 (August 8, 2011). On August 21, 2012, the D.C. Circuit issued a decision to vacate CSAPR.[g] The court ordered EPA to continue administering CAIR. *AEO 2015* assumes that CAIR remains a binding regulation through 2040.[h]

The attainment of emissions caps is typically flexible among EGUs and is enforced through the use of emissions allowances and tradable permits. Under EPA regulations, any excess SO_2 emissions allowances resulting from the lower electricity demand caused by the adoption of an energy conservation standard could be used to permit offsetting increases in SO_2 emissions by any regulated EGU. In past rulemakings, DOE recognized that there was uncertainty about the effects of energy conservation standards on SO_2 emissions covered by the existing cap-and-trade system, but it concluded that no reductions in power sector emissions would occur for SO_2 as a result of such standards.

Beginning in 2016, however, SO_2 emissions will fall as a result of the Mercury and Air Toxics Standards (MATS) for power plants. 77 FR 9304 (Feb. 16, 2012). In the final MATS rule, EPA established a standard for hydrogen chloride (HCl) as a surrogate for acid gas hazardous air pollutants (HAP), and also established a standard for SO_2 (a non-HAP acid gas) as an alternative equivalent surrogate standard for acid gas HAP. The same controls are used to reduce HAP and non-HAP acid gas; thus, SO_2 emissions will be reduced as a result of the control technologies installed on coal-fired power plants to comply with the MATS requirements for acid gas. *AEO 2015* assumes that, in order to continue operating, coal plants must have either

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[f] See *North Carolina v. EPA*, 550 F.3d 1176 (D.C. Cir. 2008); *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008).

[g] See *EME Homer City Generation, LP v. EPA*, 696 F.3d 7, 38 (D.C. Cir. 2012).

[h] On April 29, 2014, the U.S. Supreme Court reversed the judgment of the D.C. Circuit and remanded the case for further proceedings consistent with the Supreme Court's opinion. The Supreme Court held in part that EPA's methodology for quantifying emissions that must be eliminated in certain states due to their impacts in other downwind states was based on a permissible, workable, and equitable interpretation of the Clean Air Act provision that provides statutory authority for CSAPR. See *EPA v. EME Homer City Generation*, No 12-1182, slip op. at 32 (U.S. April 29, 2014). On October 23, 2014, the D.C. Circuit lifted the stay of CSAPR and CSAPR went into effect (and the CAIR sunset) in January 1, 2015. Because DOE is using emissions factors based on *AEO 2015*, the analysis assumes that CAIR, not CSAPR, is the regulation in force. The difference between CAIR and CSAPR is not relevant for the purpose of DOE's analysis of SO_2 emissions.

flue gas desulfurization or dry sorbent injection systems installed by 2016. Both technologies, which are used to reduce acid gas emissions, also reduce SO_2 emissions. Under the MATS, emissions will be far below the cap that would be established by CAIR, so it is unlikely that excess SO_2 emissions allowances resulting from the lower electricity demand would be needed or used to permit offsetting increases in SO_2 emissions by any regulated EGU. Therefore, energy conservation standards will reduce SO_2 emissions in 2016 and beyond.

CAIR established a cap on NOx emissions in eastern states and the District of Columbia. Energy conservation standards are expected to have little or no physical effect on these emissions in those states covered by CAIR because excess NOx emissions allowances resulting from the lower electricity demand could be used to permit offsetting increases in NOx emissions. However, energy conservation standards would be expected to reduce NOx emissions in the states not affected by the caps, so DOE estimated NOx emissions reductions from potential standards in the states where emissions are not capped.

The MATS limit mercury emissions from power plants, but they do not include emissions caps and, as such, DOE's energy conservation standards would likely reduce mercury emissions. DOE estimated mercury emissions reduction using emissions factors based on *AEO 2015*, which incorporates the MATS.

Power plants may emit particulates from the smoke stack, which are known as direct particulate matter (PM) emissions. NEMS does not account for direct PM emissions from power plants. DOE is investigating the possibility of using other methods to estimate reduction in PM emissions due to standards. The great majority of ambient PM associated with power plants is in the form of secondary sulfates and nitrates, which are produced at a significant distance from power plants by complex atmospheric chemical reactions that often involve the gaseous emissions of power plants, mainly SO_2 and NOx. The monetary benefits that DOE estimated for reductions in SO_2 and NOx emissions resulting from standards are in fact primarily related to the health benefits of reduced ambient PM.

Further detail is provided in chapter 13 of this TSD.

2.14 MONETIZING REDUCED CO_2 AND OTHER EMISSIONS

DOE assigned monetary values to the benefits likely to result from the reduced emissions of CO_2 and NO_X expected from each TSL considered for commercial and industrial pumps. To assign a monetary value of benefits resulting from reduced CO_2 emissions, DOE used the most current Social Cost of Carbon (SCC) values developed and/or agreed on by an interagency process. The SCC is intended to be a monetary measure of the incremental damage resulting from GHG emissions, including, but not limited to, net loss in agricultural productivity, human health effects, property damage from sea level rise, and changes in ecosystem services. Any effort to quantify or monetize the harms associated with climate change raise serious questions of science, economics, and ethics. But with full regard for the limits of both quantification and

monetization, the SCC can be used to estimate the social benefits of reductions in GHG emissions.

At the time of this final rule, the most recent interagency estimates of the potential global benefits resulting from reduced CO_2 emissions in 2015, expressed in 2013$, were $12.0, $40.0, $62.3, and $117 per metric ton avoided.[i] For emissions reductions that occur in later years, these values grow in real terms. Additionally, the interagency group determined that a range of values from 7 percent to 23 percent should be used to adjust the global SCC to calculate domestic effects, although DOE will give preference to consideration of the global benefits of reducing CO_2 emissions.

DOE multiplied the CO_2 emissions reduction estimated for each year by each of the four SCC values for that year. To calculate a present value of the stream of monetary values, DOE discounted the values in each of the four cases using the discount rates that had been used to obtain the SCC values in each case. DOE recognizes that scientific and economic knowledge continues to evolve rapidly regarding the contribution of CO_2 and other GHG to changes in the future global climate and the potential resulting damages to the world economy. Thus, the SCC values are subject to change.

DOE has estimated how the considered energy conservation standards would reduce site NO_X emissions nationwide and decrease power sector NO_X emissions in those 22 States not affected by the CAIR. DOE estimated the monetized value of net NO_X emissions reductions resulting from each of the TSLs considered for this NOPR based on estimates developed by EPA for 2016, 2020, 2025, and 2030.[j] The values reflect estimated mortality and morbidity per ton of directly emitted NO_X reduced by electricity generating units. EPA developed estimates using a 3-percent and a 7-percent discount rate to discount future emissions-related costs. The values in 2016 are $5,562/ton using a 3-percent discount rate and $4,920/ton using a 7-percent discount rate (2014$). DOE extrapolated values after 2030 using the average annual rate of growth in 2016-2030. DOE multiplied the emissions reduction (tons) in each year by the associated $/ton values, and then discounted each series using discount rates of 3 percent and 7 percent as appropriate.

DOE is investigating appropriate valuation of Hg and SO_2 emissions. DOE has not monetized estimates of SO_2 and Hg reduction in this rulemaking.

Further detail on the emissions monetization is provided in chapter 14 of the TSD.

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[i] *Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866, Technical Model Update for the Social Cost of Carbon (SCC)*. Interagency Working Group on Social Cost of Carbon, United States Government, Internal EPA Draft, February 13, 2013.
[j] www2.epa.gov/benmap/sector-based-pm25-benefit-ton-estimates

2.15 UTILITY IMPACT ANALYSIS

In the utility impact analysis, DOE analyzes the changes in electric installed capacity and generation attributable to each TSL for potential energy conservation standards. The utility impact analysis is based on output of the Energy Information Administration (EIA)'s National Energy Modeling System (NEMS). NEMS is a public-domain, multi-sectorial, partial-equilibrium model of the U.S. energy sector. Each year, the EIA uses NEMS to produce an energy forecast for the United States (the *Annual Energy Outlook*). The EIA publishes a reference case, which incorporates all energy-related policies at the time of publication, and a variety of side cases that analyze the impact of different policies, energy prices, and market trends. DOE is using a new method based on results published for the *AEO 2015* Reference case and a set of alternative cases that implement a variety of efficiency-related policies. Further detail is provided in chapter 15 of this NOPR TSD.

2.16 EMPLOYMENT IMPACT ANALYSIS

The adoption of energy conservation standards can affect employment both directly and indirectly. Direct employment effects are changes in the numbers of employees at the plants that produce commercial and industrial pumps. DOE evaluates direct employment impacts in the MIA. Indirect employment impacts may result when standards (1) cause expenditures to shift between goods (the substitution effect) or (2) impact income and overall expenditure levels (the income effect). DOE defines indirect employment impacts from standards as net jobs eliminated or created in the general economy as a result of increased spending driven by increased equipment costs and reduced spending on energy.

To investigate indirect employment impacts in the employment impact analysis, DOE uses the Pacific Northwest National Laboratory's "Impact of Sector Energy Technologies" (ImSET) model.[k] The ImSET model was developed for DOE's Office of Planning, Budget, and Analysis to estimate the employment and income effects of energy-saving technologies in buildings, industry, and transportation. Compared with approaches that simply apply an economic multiplier, ImSET allows for a more complete and automated analysis of the economic impacts of energy conservation investments. Further detail is provided in chapter 16 of the NOPR TSD.

2.17 REGULATORY IMPACT ANALYSIS

DOE prepared a regulatory impact analysis (RIA) pursuant to Executive Order 12866, Regulatory Planning and Review. 58 FR 51735 (October 4, 1993). The RIA addresses the potential for non-regulatory alternatives to energy conservation standards in improving the

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[k] M.J. Scott, O.V. Livingston, P.J. Balducci, J.M. Roop, and R.W. Schultz. *ImSET 3.1: Impact of Sector Energy Technologies: Model Description and User's Guide*. PNNL-18412, Pacific Northwest National Laboratory. May 2009. www.pnl.gov/main/publications/external/technical_reports/PNNL-18412.pdf. (Last accessed September 16, 2014.)

energy efficiency or reducing the energy consumption of the equipment covered under this rulemaking. DOE recognizes that voluntary or other non-regulatory efforts by manufacturers, utilities, and other interested parties can substantially affect energy efficiency or reduce energy consumption. DOE bases its assessment on the recorded impacts of any such initiatives to date, but also considers information presented by interested parties regarding the impacts current initiatives may have in the future. Further detail on the RIA is provided in chapter 17 of this TSD.

CHAPTER 3: MARKET AND TECHNOLOGY ASSESSMENT

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CHAPTER 3: MARKET AND TECHNOLOGY ASSESSMENT

3.1 INTRODUCTION

This chapter provides a profile of the residential boiler industry in the United States. The U.S. Department of Energy (DOE) developed the market and technology assessment presented in this chapter primarily from publicly available information. This assessment is helpful in identifying the major manufacturers and characteristics of products on the market, which form the basis of the downstream analyses.

This chapter consists of two sections: the market assessment and the technology assessment. The market assessment provides an overall picture of the market for the products concerned, including a scope of the products covered, product classes, industry structure, manufacturer market shares; regulatory and non-regulatory efficiency improvement programs; and market trends and quantities of residential boilers sold. The technology assessment identifies a list of technology options for improving residential boiler efficiency to consider in the screening and engineering analyses.

The information DOE gathers for the market and technology assessment serves as resource material for use throughout the rulemaking. DOE considers both quantitative and qualitative information from publicly available sources and interested parties.

3.1.1 Product Definitions

Residential boilers are heating devices that transfer heat from combustion gases to water or from electricity to water, which then provide heat to a home through a hot water or steam distribution system.

Residential boilers are defined in the Energy Policy and Conservation Act (EPCA) as a type of furnace. Specifically, the term "furnace" is defined as: "a product which utilizes only single-phase electric current or direct current in conjunction with natural gas, propane, or home heating oil, and which –

(A) is designed to be the principal heating source for the living space of a residence;

(B) is not contained within the same cabinet with a central air conditioner whose rated cooling capacity is above 65,000 Btu [British thermal units] per hour;

(C) is an electric central furnace, electric boiler, forced- air central furnace, gravity central furnace, or low pressure steam or hot water boiler; and

(D) has a heat input rate of less than 300,000 Btu per hour for electric boilers and low pressure steam or hot water boilers and less than 225,000 Btu per hour for forced-air central furnaces, gravity central furnaces, and electric central furnaces."

(42 U.S.C. 6291(23))

DOE has incorporated this definition into its regulations at 10 Code of Federal Regulations (CFR) 430.2. In addition, DOE has defined "electric boiler" and "low-pressure steam or hot water boiler" at 10 CFR 430.2 as follows:

> *Electric boiler* means an electrically powered furnace designed to supply low pressure steam or hot water for space heating application. A low-pressure steam boiler operates at or below 15 pounds per square inch gauge (psig) steam pressure; a hot water boiler operates at or below 160 psig water pressure and 250 °F water temperature.

> *Low-pressure steam or hot water boiler* means an electric, gas or oil burning furnace designed to supply low pressure steam or hot water for space heating application. A low-pressure steam boiler operates at or below 15 pounds psig steam pressure; a hot water boiler operates at or below 160 psig water pressure and 250 °F water temperature.

Appendix N to Subpart B of 10 CFR Part 430 references the definitions section of the American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) 103-1993 (Method of Testing for Annual Fuel Utilization Efficiency of Residential Central Furnaces and Boilers),[1] which contains additional definitions of a boiler, many of which are similar to those listed above. Specifically, ASHRAE 103-1993 defines the following terms:

> *Boiler:* a self-contained fuel-burning or electrically heated appliance for supplying low-pressure steam or hot water for space-heating application.

> *Boiler, finned-tube*: a boiler whose heat exchanger consists of only finned-tubes.

> *Boiler, low-pressure steam or hot water*: an electric, gas, or oil-burning boiler designed to supply low-pressure steam or hot water for space-heating applications. A low-pressure steam boiler operates at or below 15 psig steam pressure; a hot water boiler operates at or below 160 psig water pressure and 250°F water temperature.

3.1.2 Product Classes and Scope of Coverage

When necessary, DOE divides covered products into classes by (a) the type of energy used; (b) the capacity of the product; or (c) any other performance-related feature that justifies different standard levels, such as features affecting consumer utility. (42 U.S.C. 6295(q)) DOE then conducts its analyses and considers establishing standards at different levels for each product class.

DOE examined several possible characteristics or features that could warrant separation of covered products into different product classes. As noted in the framework document and in the initial technical analysis presented in the notice of data availability (NODA) and NOPR (79 FR 8122, Feb. 11, 2014; 80 FR 17222, Mar. 31, 2015), DOE has chosen to maintain the existing product classes for residential boilers in the analysis. The current product classes are divided by the type of energy used (fuel type) and by the heat transfer medium (*i.e.*, steam or hot water) as shown in Table 3.1.1. (See 10 CFR 430.32(e)(2).) DOE has determined that heat transfer medium is a performance-related characteristic that merits a separate product class due to the different efficiency and performance characteristics of hot water and steam boilers. In the

analysis, DOE maintained the product classes established by the Energy Independence and Security Act of 2007 (EISA 2007).

Table 3.1.1 Product Classes

Fuel Type	Heat Transfer Medium
Gas	Steam
	Hot Water
Oil	Steam
	Hot Water
Electric	Steam
	Hot Water

Although the existing product classes include electric boilers, DOE has not included electric boilers in the analysis of amended annual fuel utilization efficiency (AFUE) standards. Electric boilers do not have an AFUE requirement under 10 CFR 430.32(e)(2)(ii). The current DOE test procedure for determining AFUE considers non-weatherized boilers as indoor units and, thus considers jacket heat loss as usable heat, as those losses would go to the heated space for an indoor unit. Therefore, DOE would not expect any significant energy efficiency improvement (as measured by the DOE test procedure) as a result of setting AFUE energy conservation standards for these products. However, DOE has considered standby mode and off mode standards for electric boilers in the analysis.

DOE also did not separately analyze combination appliances that provide both space heating and domestic hot water to a residence in this analysis. DOE made this determination based on the outcome of the test procedure rulemaking. DOE has not yet adopted a test procedure to determine the energy efficiency of combination appliances in both space and water heating modes. However, federal statutes do require that combination appliances be tested and rated to provide efficiency ratings for the primary function.

3.1.3 Test Procedure

The energy conservation standards for residential boilers are represented in terms of the AFUE as measured by the DOE test procedure (see 10 CFR 430.32(e)(2)(ii)). The DOE test procedure for determining the AFUE of residential boilers is located at Appendix N to Subpart B of 10 CFR Part 430 and references ASHRAE Standard 103-1993 (*Method of Testing for Annual Fuel Utilization Efficiency of Residential Central Furnaces and Boilers*). AFUE is an annualized fuel efficiency metric that fully accounts for fuel consumption in active, standby, and off modes.

To satisfy the requirements of EPCA as amended by EISA, as noted above DOE updated its test procedure for furnaces and boilers to establish a method for measuring the electrical energy use in standby mode and off mode for residential boilers in a final rule published on October 20, 2010. 75 FR 64621. These test procedure amendments were primarily based on and incorporate by reference provisions of the International Electrotechnical Commission (IEC) Standard 62301 (first edition), *Household electrical appliances—Measurement of standby power.* On December 31, 2012, DOE published a final rule that updated the incorporation by reference of the standby mode and off mode test procedure provisions to refer to the latest edition of IEC Standard 62301 (second edition). 77 FR 76831

On July 10, 2013, DOE published a final rule in the *Federal Register* (the July 2013 final rule) that modified the existing testing procedures for residential furnaces and boilers. The modification addressed the omission of equations needed to calculate AFUE for two-stage and modulating condensing furnaces and boilers that are tested using an optional procedure provided by section 9.10 of ASHRAE 103-1993 (incorporated by reference into DOE's test procedure), which allows the test engineer to omit the heat-up and cool-down tests if certain conditions are met. 78 FR 41265. Specifically, the DOE test procedure allows condensing boilers (and furnaces) to omit the heat-up and cool-down tests provided that the units have no measurable airflow through the combustion chamber and heat exchanger during the burner off period and have post-purge period(s) of less than 5 seconds. For two-stage and modulating condensing furnaces and boilers, ASHRAE 103-1993 (and by extension the DOE test procedure) did not contain equations to calculate the heating seasonal efficiency (which contributes to the ultimate calculation of AFUE) when the option in section 9.10 is selected. The only equation that was provided in the test procedure to calculate the heating seasonal efficiency for two-stage and modulating condensing furnaces and boilers requires values for the part-load efficiencies, which are based on the results of the heat-up and cool-down tests. The July 2013 final rule adopted two new equations needed to account for the use of section 9.10 for two-stage and modulating condensing furnaces and boilers.

EPCA, as amended by EISA 2007, requires that DOE must review test procedures for all covered products at least once every 7 years. (42 U.S.C 6293(b)(1)(A)) DOE must base the analysis of amended standards on the most recent version of its test procedures. Accordingly, DOE has used the amended test procedure in considering product efficiencies, energy use, and efficiency improvements in its analyses. In December 2015, DOE published a test procedure final rule for residential furnaces and boilers.[a] Major changes adopted in the December 2015 test procedure final rule included:

- Clarifying the definition of the electrical power term PE;
- Adopting a smoke stick test for determining the use of minimum default draft factors;
- Allowing for the measurement of condensate under steady-state conditions;
- Referencing the manufacturer's installation and operations (I&O) manual and providing clarification if the I&O manual does not specify test set up;
- Specifying ductwork for units installed without a return duct;
- Specifying testing requirements for units with multiposition configurations; and
- Revising the required reporting precision for AFUE.
- Adopting a verification method for determining whether a boiler incorporates an automatic means for adjusting water temperature and whether this design requirement functions as required.

[a] For more information see: http://www.regulations.gov/#!docketDetail;D=EERE-2012-BT-TP-0024

3.2 MARKET ASSESSMENT

The following market assessment identifies manufacturer trade associations, domestic and international manufacturers of residential boilers, and regulatory and non-regulatory programs. The market assessment also describes the cost structure for the residential boiler industry and summarizes relevant market performance data.

3.2.1 Trade Association

The Air-Conditioning, Heating, and Refrigeration Institute (AHRI) is a national trade association of manufacturers of residential, commercial, and industrial appliances and equipment, including residential boilers.[b] AHRI was established in January 2008 when the Air-Conditioning and Refrigeration Institute (ARI) merged with the Gas Appliance Manufacturers Association (GAMA). AHRI develops and publishes technical standards for residential and commercial air conditioning, heating, and refrigeration equipment using rating criteria and procedures for measuring and certifying product performance. AHRI maintains the *Directory of Certified Product Performance* that lists all products that it has certified for performance, including a certified performance directory for residential boilers. DOE used the data in the AHRI certification directory for residential boilers in its market assessment.

3.2.2 Manufacturers and Market Share

DOE constructed a database of residential boilers based on its review of the AHRI directory of certified performance for residential boilers,[2] manufacturers' websites and product catalogs, the ENERGY STAR® listing of qualified residential boilers,[3] the California Energy Commission (CEC) appliance efficiency database,[4] and the DOE certification and compliance management system[5] (CCMS) database to create a comprehensive database of residential boilers available on the market. DOE examined this database to identify residential boiler manufacturers. DOE does not have empirical data on the market shares of particular manufacturers of residential boilers. However, as shown in Table 3.2.1, DOE divided manufacturers into "major" and "other" based on DOE research and discussions with manufacturers. Major manufacturers are estimated to have a market share of at least 15 percent, and the rest of the manufacturers are considered as other.

Table 3.2.1 Residential Boiler Manufacturers

Company	Parent Name (if applicable)	Market
Lochinvar Corporation	A.O. Smith Water Products Company	Other
Crown Boiler Company	Burnham	Major
Burnham Commercial		
Burnham Hydronics (US Boiler Company, Inc.)		
New York Boiler Company, Inc.		
Argo	ECR International	Major

[b] For more information see: http://www.ahrinet.org/site/318/About-Us.

ECR International, Ltd - Olsen Division		
Oneida Royal		
Dunkirk Boilers		
Pennco, Inc.		
Utica Boilers, Inc.		
Ultimate Engineering		
Hydrotherm	Mestek	Other
Smith Cast Iron Boilers		
Embassy Industries, Inc.		
RBI Water Heater		
Raypak, Inc.	Paloma Industries	Other
Weil-McLain	SPX Corporation	Major
Williamson-Thermoflo		
Bosch	Bosch	Other
Buderus		
Viessmann	Viessmann Manufacturing Company	Other
LAARS Heating Systems	Bradford White	Other
Axeman-Anderson	Axeman-Anderson	Other
Boyertown Furnace Company	Boyertown Furnace Company	Other
Navien	Kyung Dong Network Co, Ltd.	Other
Columbia Boiler Company	Vari Corporation	Other
Thermo-Dynamics Boiler Company		
Electric Furnace Man		
Camus Hydronics	Camus Hydronics	Other
Energy Kinetics	Energy Kinetics	Other
NY Thermal	Dennison Holdings Ltd.	Other
Triangle Tube	ACV International NV	Other
SIME North America	SIME	Other
Heat Transfer Products, Inc.	Heat Transfer Products, Inc.	Other
PB Heat LLC	Peerless Boilers	Other
Slant/Fin Corporation	Slant/Fin Corporation	Other
Thermolec	Thermolec	Other
Allied Engineering Company	E-Z-Rect Manufacturing Ltd.	Other
Grandby Industries	Pensotti	Other
De Dietrich	DDR Americas, Inc.	Other
IBC Technologies, Inc.	IBC Technologies, Inc.	Other
BRD Thermea	Baxi Spa	Other

3.2.3 Potential Small Business Impacts

DOE also considers the impact of amended energy conservation standards on small

businesses. The U.S. Small Business Administration (SBA) lists small business size standards for industries as they are described in North American Industry Classification System (NAICS). For residential boilers, the size standard is matched to NAICS code 333414, heating equipment (except warm-air furnaces) manufacturing. The number of employees in a small business is combined with the total employees of the parent company; it does not represent the division manufacturing residential boilers. DOE has identified nine small businesses in the residential boiler market that fall under the SBA's definition as having 500 employees or fewer. 13 CFR part 121. DOE studies the potential impacts on these small businesses in detail during the manufacturer impact analysis, which can be found in chapter 12 of this final rule TSD.

DOE has identified the following small business manufacturers of residential boilers:

- Axeman Anderson
- Vari Corporation
- Energy Kinetics
- Hamilton Engineering
- ECR International
- Heat Transfer Products, Inc.
- Peerless Boiler
- Slant/Fin Boiler
- Triangle Tube

3.2.4 Distribution Channels

Two distribution channels represent the majority of the heating, ventilating, and air conditioning HVAC market. In the replacement market the original equipment manufacturer (OEM) assembles the system and sells it to a wholesaler; the wholesaler sells the unit to a contractor (also known as a dealer); and the contractor sells the unit to the final consumer and performs the installation. In the replacement market, the final consumer is usually the homeowner, as illustrated in Figure 3.2.1, and is very influential in product selection. Replacements "in kind" (replacing a unit with a similar or identical product) are common, although premium products are also commonly sold in this market. In the new construction distribution channel, the manufacturer sells to the equipment wholesaler, who in turn sells to the mechanical contractor, who in turn sells it to the general contractor, who sells to the consumer. DOE also considered a national accounts distribution channel for residential boilers used in commercial applications. Further details about each of these distribution channels are included in the markups analysis, which can be found in chapter 6 of this final rule TSD.

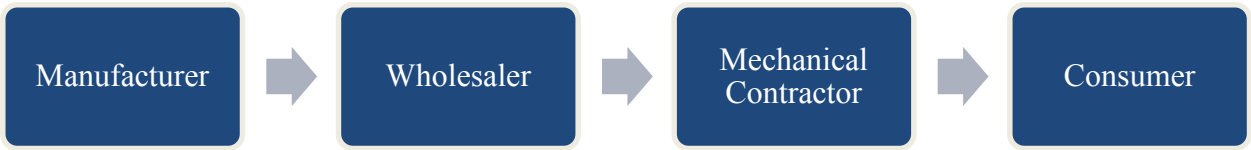

Figure 3.2.1 Replacement Distribution Channel

Figure 3.2.2 New Construction Distribution Channel

Figure 3.2.3 National Account Distribution Channel

3.2.5 Regulatory Programs

The following section details current regulatory programs mandating energy conservation standards for residential boilers. Section 3.2.5.1 discusses current federal energy conservation standards. Section 3.2.5.2 reviews Canadian energy conservation standards that may affect the companies servicing the North American market. Section 3.2.5.3 reviews the United Kingdom's energy conservation standards.

3.2.5.1 Current Federal Energy Conservation Standards

Part A of Title III of EPCA addresses the energy conservation standards for consumer products other than automobiles, which include residential boilers. (42 U.S.C. 6291-6309) The current federal standards prescribed by EPCA, shown in Table 3.2.2, have applied since September, 1, 2012.

Table 3.2.2 Federal Energy Conservation Standards Established by EISA

Product Class	Minimum Annual Fuel Utilization Efficiency %	Design Requirements
Gas Hot Water	82	No constant burning pilot, automatic means for adjusting water temperature
Gas Steam	80	No constant burning pilot
Oil Hot Water	84	Automatic means for adjusting temperature
Oil Steam	82	None
Electric Hot Water	None	Automatic means for adjusting temperature
Electric Steam	None	None

3.2.5.2 Canadian Energy Conservation Standards

The Natural Resources Canada (NRCan) Office of Energy Efficiency regulation mandates energy conservation standards for residential boilers that apply to imports and interprovincial trade. The standards for boilers are expressed as minimum AFUE, rated according to the Canadian test standard CAN/CSA P.2-2007, *Testing method for measuring annual fuel utilization efficiency of residential gas-fired furnaces and boilers;* (*CSA P.2*). The Canadian boiler standards are shown in Table 3.2.3. The AFUE standards became effective in September 1, 2010, and the prescriptive requirements became effective on September 1, 2012.[6]

Table 3.2.3 Canadian Energy Conservation Standards for Residential Boilers

Boiler Type	Minimum AFUE %	Prescriptive Requirements
Gas Hot Water	82	No constant burning pilot; Automatic means for adjusting water temperature
Gas Steam	80	No constant burning pilot
Oil Hot Water	84	Automatic means for adjusting water temperature
Oil Steam	82	None
Electric Hot Water	None	Automatic means for adjusting water temperature

3.2.5.3 United Kingdom Energy Conservation Standards

The United Kingdom Department of Energy and Climate Change uses the standard assessment procedure (SAP) methodology to assess and compare the energy and environmental performance of dwellings. The SAP uses the seasonal efficiency of domestic boilers in the UK (SEDBUK), which provides an average annual efficiency of boilers operating in typical domestic

conditions. Part L1 of the building regulations code in the United Kingdom requires that all gas-fired boilers installed in England or Wales after April 1, 2005, and all oil-fired boilers installed after April 1, 2007, must be condensing and must be rated A or B on the SEDBUK scale.[7]

Table 3.2.4 SEDBUK Efficiency Bands

Efficiency Band	SEDBUK %
A	90 and above
B	86–90
C	82–96
D	78–82
E	74–78
F	70–74
G	Below 70

3.2.6 Non-Regulatory Programs

DOE identified non-regulatory programs aimed at improving the energy efficiency of residential boilers. Two such programs are based on voluntary efficiency targets for residential boilers: the ENERGY STAR program and the Consortium for Energy Efficiency (CEE) initiative.

3.2.6.1 ENERGY STAR

ENERGY STAR is a voluntary labeling program conducted by EPA and DOE that identifies and promotes energy-efficient products. To qualify, a product must usually exceed federal minimum standards by a specified amount, or if no federal standard exists, it must meet minimum efficiency levels set by the program and/or exhibit selected energy-saving features. ENERGY STAR maintains energy efficiency specifications for various products, including residential boilers. Table 3.2.5 shows the ENERGY STAR level, which took effect April 1, 2002 and expired in October 2014. The new ENERGY STAR efficiency levels divide residential boilers by fuel type and took effect October 1, 2014. [8]

Table 3.2.5 ENERGY STAR Requirements for Qualifying Residential Boilers Prior to October 1, 2014

Product	Efficiency Level (AFUE) %
Residential Boiler	85

Table 3.2.6 ENERGY STAR Requirements for Qualifying Residential Boilers After October 1, 2014

Product	Efficiency Level (AFUE) %
Gas Residential Boilers	90
Oil Residential Boilers	87

3.2.6.2 Consortium for Energy Efficiency

The CEE is a coalition of energy efficiency programs in the United States and Canada engaged in establishing common goals and methods for promoting energy efficiency across a broad range of products. It includes state energy efficiency offices, energy efficiency advocacy groups, and utilities. The CEE high-efficiency residential gas heating initiative promotes the use of high-efficiency gas residential boilers. CEE identifies two tiers of efficiency levels for residential boilers, listed in Table 3.2.7.[9]

Table 3.2.7 CEE Efficiency Tiers for Residential Gas Boilers

Tier	AFUE Rating %
Tier 1	85
Tier 2	90

3.2.6.3 Consumer Rebate Program

In addition to the federal and state tax credits available for purchasers of residential boilers, many states and local utility companies offer rebates for higher efficiency boilers. They are typically for existing homes and retrofits only. DOE maintains a database of such rebates, the Database of State Incentives for Renewables and Efficiency (DSIRE),[10] as well as information on other state, local, utility, and federal incentives and policies that promote renewable energy and energy efficiency. For more information on individual rebate programs, visit the DSIRE website at www.dsireusa.org.

3.2.6.4 Federal Tax Credits

Until December 31, 2010, a federal tax credit provided consumers with a $150 credit toward their federal income tax if they purchased qualifying residential boilers. To qualify for the federal tax credit a hot water boiler should have an AFUE of 95 or greater.[10] There are currently no federal tax credits for high-efficiency residential boilers.

3.2.7 Product Lifetime

The lifetime of residential boilers can vary significantly depending on how often the system is used (which is dependent upon the climate of the region where the product is installed and the personal preferences of the consumer) and how regularly it is maintained and serviced.

DOE used national survey data and manufacturer shipment data to calculate the distribution of residential boiler lifetimes. DOE reviewed available literature to determine the appropriate lifetime for residential boilers.

DOE estimated that the average lifetime as being 26.5 years for hot water gas-fired boilers, 23.6 years for steam gas-fired boilers, 24.7 years for hot water oil-fired boilers, and 19.2

years for steam oil-fired boilers. DOE's methodology for determining the lifetime of the products under analysis are described in detail in appendix 8F of this final rule TSD.

DOE interviewed several manufactures to gather information regarding the lifetime of residential boilers. Many manufacturers stated that the design and efficiency level of the boiler affects the expected lifetime. During manufacturer interviews conducted for the initial and NOPR analyses, several manufacturers stated that higher efficiency condensing boilers, made of stainless steel or cast aluminum, often have shorter lifetimes than lower efficiency cast iron boilers. Manufacturers pointed to the warranties offered on both types of heat exchangers to substantiate their claims. However, these manufacturers also generally noted that condensing residential boilers have only been available a relatively short time, so estimating the lifetime is difficult.

3.2.8 Market Performance Data

As explained previously, DOE examined several sources to compile a comprehensive database of residential boilers available on the market today. This database contains information such as manufacturer name, model number, input capacity, efficiency, and other physical and performance characteristics. DOE only examined products that meet EPCA's definition of a residential boiler (see section 3.1 in this chapter). Table 3.2.8 shows the number of the models in the DOE database for each product class. As Table 3.2.8 indicates, the majority of residential boilers on the market are gas-fired hot water boilers.

Table 3.2.8 Number of Boiler Models Listed in DOE's Residential Boiler Database by Product Class

Product Class	Number of Models as of Aug 2015
Gas-Steam	95
Gas-Hot Water	762
Oil-Steam	80
Oil-Hot Water	501

3.2.9 Efficiency Data

DOE characterized the distribution of boiler efficiencies available to consumers by separating the active models listed in the DOE database into their respective product classes (section 3.1) and placing the models into bins based on their efficiency. The efficiency ratings were rounded to the nearest whole percentage as specified in 10 CFR 430.23(n)(2) and separated into bins by rounding to the nearest 1 percent AFUE (*e.g.,* 83.7 is in the 84 AFUE bin). DOE then counted the number of models in each efficiency bin to examine the distribution of product efficiency.

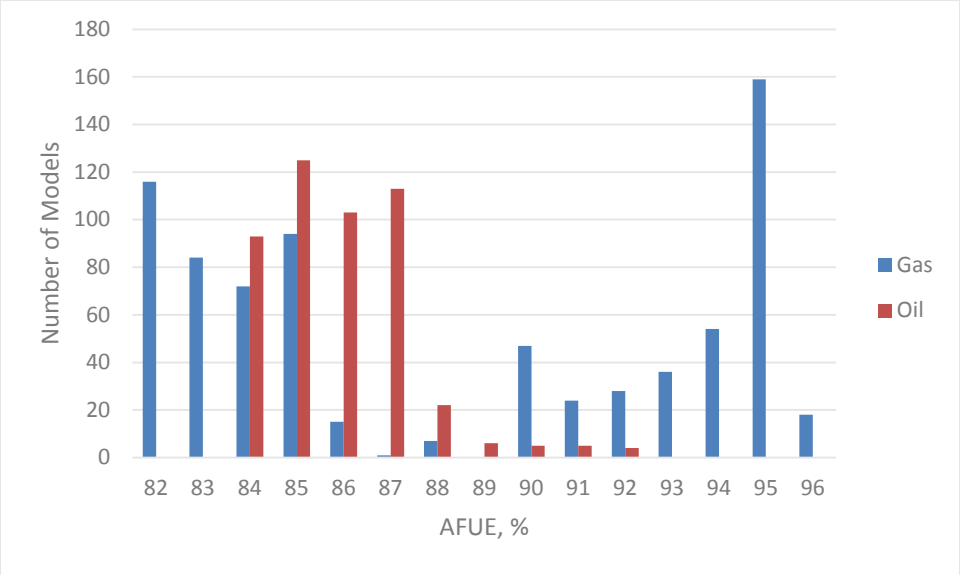

Figure 3.2.4 AFUE Ratings for Residential Hot Water Boilers in the DOE Database

As shown in Figure 3.2.4, hot water boiler models generally fall into one of two ranges – non-condensing (*i.e.*, 82 to 86 percent AFUE for gas-fired hot water boilers) or condensing (*i.e.*, at or above 90 percent AFUE for gas-fired hot water boilers). The efficiency distribution of the boilers varies based upon the fuel type used. This is because of the chemical makeup of the fuel combustion byproducts. Gaseous fuels such as ntural gas and propane have a higher hydrogen content, which causes more water vapor to be formed during combustion. This results in lower efficiencies in non-condensing gas boilers. Most non-condensing boilers are concentrated at 82 percent AFUE for gas-fired hot water boilers and 85 percent AFUE for oil-fired hot water boilers. Most condensing boilers are at either 90 or 95 percent AFUE for gas-fired hot water boilers.

The majority of oil boilers on the market are non-condensing (*i.e.*, less than 90 percent AFUE), however there are a small number of oil-fired condensing boiler models and most are at 90 and 91 percent AFUE. Condensing oil boilers are less common due in part to the high sulfur content of heating oil, which can cause additional maintenance and corrosion issues. New limits on maximum sulfur content of heating oil in the Northeast may reduce these issues. Using low-sulfur heating oil with boiler systems can not only reduce the emission of particulate matter, but also allows for the use of a secondary condensing heat exchanger.

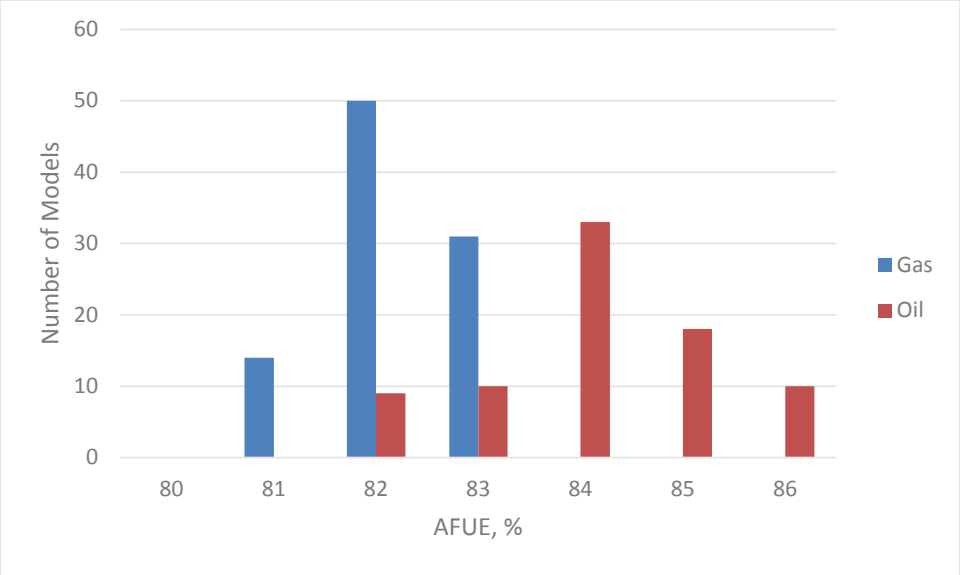

Figure 3.2.5 AFUE Ratings for Residential Steam Boilers in the DOE Database

As shown in Figure 3.2.5, gas-fired residential steam boilers have efficiencies ranging from 81 percent AFUE to 83 percent AFUE. Oil-fired residential steam boilers have efficiencies ranging from 82 percent AFUE up to 86 percent AFUE. As with hot water boilers, the efficiency of the boilers varies based upon the fuel type used. There are no higher level efficiencies in steam boilers.

3.2.10 Shipments

Information about annual residential boiler shipment trends allows DOE to estimate the impacts of energy conservation standards on the residential boiler industry. DOE used historical shipments data from *Appliance Magazine*, AHRI, and ENERGY STAR to populate its shipments model for residential boilers. DOE used shipment projections to calculate the national impacts of standards and to calculate the future cash flows of manufacturers. DOE developed shipments projections based on an analysis of key market drivers for a particular product (see chapter 9).

DOE used this data for two main purposes. First, the shipment data and market trend information contributed to the shipments analysis and no-new-standards case (*i.e.*, without new or amended standards) forecast for residential boilers (chapter 9). Second, DOE used the data to develop the installed stock of equipment for the national impact analysis (chapter 10). More detailed shipments data are given in chapter 9 and appendix 9A of the TSD.

3.3 BOILER TECHNOLOGY ASSESSMENT

The technology assessment focuses on understanding how residential boilers use energy and on identifying potential technology changes that would improve the efficiency of these products. Measures that improve the rated product efficiency are analyzed as technology options. The technologies identified in this assessment are based on existing technologies as well as working prototypes. In consultation with interested parties, DOE has created a list of technology options for consideration in this rulemaking. Following research into this list of technology

options, those technology options that pass the screening criteria are considered suitable options for improving the efficiency of the product in the engineering analysis, and will assist DOE in determining the max-tech design as well as the cost of improving product efficiency.

At this time, DOE is aware of a set of technology options (discussed in further detail below) that could be used to improve residential boiler efficiency. The technologies listed in sections 3.3.2 and 3.3.3 focus on measures that would improve either the rated AFUE or reduce standby and/or off mode electrical energy consumption. DOE is aware of technologies that improve overall efficiency of residential boilers but do not improve AFUE or reduce standby/off mode energy consumption as measured by the DOE test procedure, and these technologies are described in section 3.3.4.

3.3.1 Boiler and Heat Exchanger Characterization

Fuel burning boilers transfer heat from the combustion gases to water, which is then sent to the heated space through a steam or hot water distribution system. The technology used for steam boilers is generally the same as for hot-water boilers except that circulating pumps are not required in steam boilers.

Residential boilers can be characterized by the type of heat exchanger material. Cast-iron, steel, stainless steel, copper, and aluminum are the most commonly used heat exchanger materials. The heat exchanger's function is to transfer heat from the combustion gases to the heating medium (*e.g.*, hot water or steam), which is then distributed to the heated space. Various types of heat exchangers are commonly used in residential boilers.

Most non-condensing boilers are made with cast iron, copper, or steel heat exchangers. The most common heat exchanger design used in residential hot water and steam boilers is the cast-iron sectional boiler. In this design, water is heated in cast-iron chambers called sections. The sections are fit together to form an assembly, which is typically assembled horizontally. Hot combustion gases form in the combustion chamber near the bottom of the boiler and rise through cavities between the sections, transferring heat to the water within. Generally, the greater the number of sections, the greater the rate of heat output from the boiler.

There are two major categories of cast-iron boiler: dry base and wet base. A dry-base boiler is commonly used in atmospheric gas-fired boilers. In a dry-base boiler, the combustion chamber is under the fluid-backed sections. Combustion occurs on the surface of burner tubes suspended below the water-filled sections. Hot exhaust gases are drawn upward between boiler sections, or through fire tubes, and enter a flue gas collector at the top of the boiler. A wet-base boiler is a common configuration for oil-fired boilers. In a wet-base boiler, the top and sides of the combustion chamber are enclosed by fluid-backed sections. It has the advantage of exposing more of the section's surface area to the combustion chamber, which is completely surrounded by the water-filled heat exchanger.[11]

The amount of metal in cast-iron boilers makes them relatively heavy. These boilers can contain up to 15 gallons of water. The combination of metal and water weight enables them to absorb a significant amount of heat into their own material. This high thermal mass is

undesirable in situations where the boiler is significantly oversized, and thus experiences extended periods of off-time between firing cycles. During this time, residual heat remaining in the boiler's metal and water following burner shutdown can be carried up to the flue by air currents passing through the combustion chamber. The majority of gas-fired boilers have flue dampers to reduce the draft heat loss. The residual heat is also transferred through the boiler's jacket to the air surrounding the boiler.

Another commonly used heat exchanger design in non-condensing gas-fired residential hot water boilers is the copper water-tube boiler. In copper water-tube boilers, the outside of the tubes are directly exposed to the combustion gases. Design variations include both vertical and horizontal-tube arrangements. The tubes are usually manufactured with fins that increase the heat transfer area exposed to the flue gases. The high thermal conductivity of copper, relative to cast iron or steel, means that significantly less surface area is needed to achieve the same rate of heat transfer. This makes for smaller and significantly lighter boilers. Copper water-tube boilers require constant water circulation while being fired to prevent damage from thermal stress. This requirement must be incorporated into the design of system piping and control.

The third material commonly used in non-condensing boilers is steel. In a steel fire-tube boiler, water surrounds a group of steel tubes through which the hot combustion gases pass. Spiral baffles known as turbulators are inserted into the fire tubes to increase heat transfer by inducing turbulence and slowing the passage of the exhaust gases. The fire tubes are welded to steel bulkheads at each end to form the overall heat exchanger assembly. Most steel boilers are built around horizontal fire tubes. Some boilers route the flue gases through multiple tubes before they reach the flue-pipe connection. This allows additional heat to be extracted from the flue gases.

Condensing boilers are typically made from corrosion-resistant metals such as stainless steel or aluminum, as other metals will corrode due to the acidic condensate that occurs as a byproduct of the condensing process. Condensing boilers have a variety of different heat exchanger designs. Design variations include fire tube or water tube, and at least one manufacturer offers a primary heat exchanger that is sectional cast iron with a secondary condensing heat exchanger. The majority of condensing boilers are gas fired. Condensing boilers are typically forced or induced draft because they cannot use a natural draft venting system as the buoyancy of the cooler flue gases is not sufficient to draw the gases up the vent system. Condensing boilers are generally sold with more sophisticated controls than non-condensing boilers, and are often viewed as premium products and are equipped with additional features.

In the non-condensing range (*i.e.*, 82 to 88 percent AFUE) the majority of the gas hot water boilers heat exchangers are made of cast iron, and a smaller number of models are comprised of copper or steel. The heat exchanger of a baseline unit is typically constructed from cast iron. In the condensing range (*i.e.*, at or above 90 percent AFUE) the majority of heat exchangers are stainless steel with a smaller number of models made of aluminum. There are also a few condensing boilers made of cast iron some of which have an additional stainless steel heat exchanger.

In the non-condensing range the heat exchangers of oil fired hot water boilers are mostly made of cast iron; a smaller number are made of steel. At condensing levels, oil-fired boiler heat exchangers are made of cast iron and steel.

3.3.2 Technology Options That May Improve AFUE

DOE has identified the following technology options, which have the potential to improve the efficiency of residential boilers.

1. Heat exchanger improvements
2. Modulating operation
3. Dampers
4. Direct vent
5. Pulse combustion
6. Premix burners
7. Burner derating
8. Low-pressure air-atomized oil burner
9. Delayed-action oil pump solenoid valve
10. Electronic ignition

3.3.2.1 Heat Exchanger Improvements

Improving the heat exchanger for boilers increases the rate of transfer from the hot combustion gases to the heating medium (*i.e.*, hot water or steam), which is then distributed to the heated space. The improved heat transfer increases the thermal efficiency and AFUE.

Improvements to the heat exchanger can be achieved by modifying baseline designs of standard boilers to (1) increase heat exchanger surface area, (2) modify or add heat exchanger surface features, (3) modify or add heat exchanger baffles and turbulators, and (4) increase the corrosion resistance of the heat exchanger to withstand flue gas condensation.

Increase heat exchanger surface area and add mechanical draft. The performance of the heat exchanger can be improved by increasing the surface area relative to the fuel input. An increase in surface area provides a larger surface over which heat transfer can occur. This increases the overall rate of heat transfer occurring in the boiler, thereby improving the boiler's ability to efficiently extract heat from the hot combustion gases. The result is an increase in steady-state efficiency of the unit, and thus the AFUE.

Mechanical draft systems can be added to boilers to enable the use of more efficient heat exchangers. Mechanical draft systems allow for increased heat exchange surface area and/or tighter flueways by overcoming the drop in pressure associated with restrictive flow passages in more efficient heat exchangers and by supplementing the loss of buoyancy in cooler flue gases to provide sufficient airflow. Mechanical draft systems can be designed as either induced draft or forced draft systems. An induced draft fan is located downstream of the heat exchanger and pulls flue gases through the gas pathway, creating negative pressure in the heat exchanger. A

forced draft fan is located upstream of the heat exchanger and creates positive pressure in the heat exchanger that pushes the products of combustion through the system.

Modify or add heat exchange surface features. An alternative to increasing the size of the heat exchanger is enhancing the effectiveness of the heat exchanger surfaces. One way this may be done is by adding surface features to the heat exchanger. Incorporating surface features, such as dimples, increases the turbulence in the air passing close to the heat exchanger's surface, which can enhance heat transfer when correctly designed.

Induce turbulence in heat exchanger baffles and turbulators. Turbulators and baffles are pieces of metal that are incorporated into the heat exchanger to improve the heat transfer through the walls of the heat exchanger by inducing turbulence and slowing the passage of the exhaust gases through the heat exchanger.

Increase the corrosion resistance of the heat Exchanger. When efficiency of a combustion heating appliance is increased to the point where combustion gases are cooled below the dew point of the gas, condensate will form. Flue gas condensate is acidic and corrosive. Corrosion due to condensation of flue gases limits the AFUE that can be achieved by boilers with heat exchangers made from materials that are less resistant to corroding, such as cast iron and copper. Using heat exchangers made out of more corrosion-resistant materials, such as cast aluminum and stainless steel, allows for the recovery of the latent heat (the heat from condensation of water vapor in the combustion products) and raises the AFUE to above 90 percent. These types of boilers require the addition of a condensate pump and mechanical draft system.

3.3.2.2 Modulating Operation

Two-stage and modulating combustion allows boilers to meet heating load requirements more precisely. When low heating load conditions exist, a two-stage or modulating boiler can operate at a reduced input rate for an extended period of burner on-time to meet the reduced heating load. When combustion air supply is also modulated to match the fuel input rate, the burner is essentially derated, making the heat exchanger more effective in periods of lower heat demand, raising the AFUE.

The primary difference between two-stage and step-modulating control is that the two-stage control must operate between either the low firing rate and off or the high firing rate and off; the continuous modulating control has more firing rates and can operate between multiple firing rates.

3.3.2.3 Dampers

Off-cycle (which refers to the burner off-cycle) dampers restrict the intake and exhaust air flow through the venting system during standby mode by closing when the burner is not operating, thereby trapping residual heat in the heat exchanger. During the burner off-cycle, the boiler loses heat by natural convection and conduction through the combustion air inlet and flue. Installing a damper at these points improves AFUE by preventing heat from escaping and

minimizing off-cycle heat losses. Most atmospheric boilers have dampers, including those at the baseline efficiency level.

3.3.2.4 Direct Vent

Direct-vent appliances use ducts to provide outdoor air for combustion. Non-direct-vent appliances typically use air from the appliance's environment for combustion. Direct-vent systems may use a combustion-air preheat system that passes the outdoor combustion air through a heat exchanger in contact with the flue gases. The combustion air does not mix with the flue gases. The so-called direct-vent with preheat design uses a concentric vent/combustion air system in which the flue gases pass through a central-vent pipe and the combustion air passes through a concentric duct surrounding it. This arrangement creates a counter-flow heat exchanger that recovers some heat from the flue gases to preheat the combustion air.

The direct-vent-without-preheat design is the same as the direct-vent-with-preheat design, except that the combustion air is not preheated by the flue gases. There are separate vent and combustion air systems and the combustion air is not preheated. The current test procedure does not differentiate between the performances of direct-vent with and without preheat technology; both are evaluated as isolated combustion system installations. Using direct vent improves the AFUE rating because the heat loss through infiltration is reduced.

3.3.2.5 Pulse Combustion

Pulse combustion burners operate on self-sustaining resonating pressure waves that alternately rarefy the combustion chamber (drawing a fresh fuel-air mixture into the chamber) and pressurize it (causing ignition by compression heating of the mixture to its flash point). Pulse combustion systems feature high heat transfer rates, and have a high combustion efficiency compared to conventional boiler designs. Similar efficiencies can be achieved through the use of other technologies, and manufacturers typically no longer use this technology to improve efficiency.

3.3.2.6 Premix Burners

Premixing fuel gas and combustion air prior to arrival at the flame results in more complete combustion using lower levels of excess air. The lower levels of excess air raise the temperature of the gases entering the heat exchanger, which enhances heat exchange and improves efficiency. Lower levels of excess air also raise the water vapor dew point which facilitates condensation and the recovery of latent heat and improves AFUE. Premix burners have lower NOx emissions than traditional burners.

3.3.2.7 Burner Derating

Reducing burner firing rate for gas and oil boilers while keeping heat exchanger geometry and surface area and the fuel-air ratio the same will increase the ratio of heat transfer surface area to energy input, thereby increasing the AFUE. However, the lower energy input means that less heat would be provided than with conventional burner firing rates.

3.3.2.8 Low-Pressure, Air-Atomized Oil Burner

The residential oil burner market is currently dominated by the pressure-atomized retention head burner. The fuel input rate is controlled by the size of the nozzle orifice. Pressure-atomizing nozzles that are designed for low firing rates suffer rapid fouling of the small internal passages, leading to bad spray patterns and poor combustion performance. To overcome the low input limitations of conventional oil burners, Brookhaven National Laboratory[12] developed a low-pressure, air-atomized oil burner. In addition, it can operate with low levels of excess combustion air for lean-burning, ultra-clean combustion. A lower level of excess air generally improves AFUE rating.

3.3.2.9 Delayed-Action Oil Pump Solenoid Valve

A delayed-action oil pump solenoid valve is installed between the oil pump and the burner nozzle to supplement the fuel pump regulator. It does so by delaying the fuel release by three to six seconds after the igniter and burner blower start until the oil pressure reaches the level required to fully discharge the oil into the combustion chamber without dripping. This ensures that the oil burns more completely, which improves efficiency.

3.3.2.10 Electronic Ignition

Boilers are equipped with electronic ignition systems, which light the burner with an electrical component upon a call for heat. Unlike standing pilot ignition systems that consume fuel continuously, electronic devices and their control modules operate only during the active mode, which improves AFUE. Electronic ignition is already required for all gas boilers and is present on oil boilers.

There are different types of electronic ignition systems including:
(1) Hot surface ignition: The igniter in this system is an electrically heated resistance element that thermally ignites the main burner directly without the use of a pilot light.
(2) Intermittent pilot ignition: This device lights a pilot light by generating a spark. The pilot light in turn lights the main burner.
(3) Direct spark ignition: DSI ignites the main burner directly by generating a spark.
(4) Interrupted duty ignition systems: all modern oil burners have a type of electronic ignition called interrupted duty ignition. A step-up transformer supplies power to two electrodes, which causes a spark to jump. The interrupted duty ignition system for an oil burner activates the spark only until either a steady flame is established or the end of a timed trail-for-ignition period.

3.3.3 Technology Options that Improve Standby Mode and Off Mode Energy Efficiency

On October 20, 2010, DOE published a final rule in the *Federal Register* in which it concluded that it is not technologically feasible to create an integrated metric that incorporates standby mode and off mode energy consumption into the statutorily identified efficiency descriptor, AFUE. The October 2010 final rule amended DOE's test procedure for furnaces and boilers to establish a method for measuring the electrical energy use in standby and off mode for gas and oil-fired boilers pursuant to requirements established by EISA 2007. 75 FR 64621. The

technologies described in this section would reduce the standby mode and off mode energy consumption as measured by the DOE test procedure.

3.3.3.1 Transformer Improvements

Transformers continue to supply power to the control board in all modes of operation, including standby mode. Increasing their operating efficiency will reduce the boiler's standby electrical power consumption.

A toroidal transformer has an annular core made of very tightly wound, grain-oriented, silicon steel ribbons, which are arranged so that all their molecules are aligned with the direction of flux. This allows better performance (*i.e.*, more quiet and efficient operation) than a traditional laminated transformer, in which unaligned molecules increase the core's reluctance, or capacity, for opposing magnetic induction. These improvements in efficiency allow an up to 50 percent reduction in size and weight, such that they can be used in new, innovative applications. Overall efficiency of toroidal transformers is 90 to 95 percent.[13]

Research has shown that larger, low loss transformers use four times less energy in standby than do off-the-shelf transformers.[14]

3.3.3.2 Control Relay for Models with Brushless Permanent Magnet Motors

During testing of standby and off mode components performed for the DOE furnace and central air conditioner rulemaking,[c] DOE found that brushless permanent magnet (BPM) motors and their associated controls consume power while in standby and/or off modes, while permanent split capacitor motors did not have any standby or off mode power draw. Therefore, the BPM motor and associated controls could be disconnected while the system is in standby mode or off mode via a control relay to further reduce a system's standby/off mode power consumption. A typical control relay activates a switch when current runs through it; when there is no current, a spring holds the switch in the open position.

3.3.3.3 Switching Mode Power Supply

While linear power supplies regulate voltage supply to the DC circuit with a series element, switching mode power supplies (SMPS) do so in an alternative, more effective way. In a SMPS, power-handling electronics switch on and off (where on means the switch is closed and voltage drop is negligible, and off means the switch is open and current is negligible) with high frequency. This effectively connects or disconnects the output (load) to the input source. Continuous power flow to the load can be maintained and controlled by varying the duty cycle or frequency of the SMPS.

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[c] http://www1.eere.energy.gov/buildings/appliance_standards/residential/residential_furnaces_cac_hp_final_rule.html

Linear power supplies experience significant heat losses because they use resistance elements, which convert electrical energy to heat energy, to regulate power supply. By using a switch to control energy flow instead, switching mode power supplies avoid such heat losses and have much higher efficiency. SMPS do introduce transient losses that increase with frequency, but these losses are negligible in comparison with the energy saved. Thus, replacing a linear power supply with an SMPS has the potential to reduce the electrical power consumption of residential boilers in standby and off mode.

3.3.4 Technologies That Do Not Increase AFUE or Standby

DOE has listed technologies that may improve overall efficiency of residential boilers but do not improve AFUE or reduce standby/off mode energy consumption as measured by the DOE test procedure. DOE did not consider these technologies beyond the screening analysis because they do not affect the rated efficiency. Chapter 4 provides more detail on these technologies.

- Micro combined heat and power (micro-CHP)
- Improved motor efficiency
- Positive shut-off valve for oil burner nozzles
- Heat pump boilers

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CHAPTER 4. SCREENING ANALYSIS

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CHAPTER 4. SCREENING ANALYSIS

4.1 INTRODUCTION

This chapter discusses the screening analysis conducted by the U.S. Department of Energy (DOE) of the technology options identified in the market and technology assessment for residential boilers (chapter 3). In the market and technology assessment, DOE presented an initial list of technology options that can be used to improve the energy efficiency and/or reduce energy consumption of residential boilers. The goal of the screening analysis is to identify any technology options that will be eliminated from further consideration in the rulemaking analyses.

The candidate technology options are assessed based on information gathered during DOE research, as well as inputs from stakeholders including manufacturers, trade organizations, and energy efficiency advocates. Technology options which are judged to be viable approaches for improving energy efficiency are retained as inputs to the subsequent engineering analysis. Technology options which are not incorporated in commercial products or in working prototypes, or that fail to meet certain criteria as to practicability to manufacture, install and service, as to impacts on product utility or availability, or as to health or safety will be eliminated from consideration in accordance with 10 CFR 430, subpart C, appendix A, section 4(a)(4)(i-iv).

DOE uses the following four screening criteria to determine which technology options are suitable for further consideration in an energy conservation standards rulemaking:

1. Technological feasibility. DOE will consider technologies incorporated in commercial products or in working prototypes to be technologically feasible.

2. Practicability to manufacture, install, and service. If mass production and reliable installation and servicing of a technology in commercial products could be achieved on the scale necessary to serve the relevant market at the time the standard comes into effect, then DOE will consider that technology practicable to manufacture, install, and service.

3. Adverse impacts on product utility or product availability. If DOE determines a technology would have a significant adverse impact on the utility of the product to significant subgroups of consumers, or would result in the unavailability of any covered product type with performance characteristics (including reliability), features, sizes, capacities, and volumes that are substantially the same as products generally available in the United States at the time, it will not consider this technology further.

4. Adverse impacts on health or safety. If DOE determines that a technology will have significant adverse impacts on health or safety, it will not consider this technology further.

4.2 TECHNOLOGIES THAT DO NOT IMPACT AFUE OR STANDBY AND OFF MODE ENERGY CONSUMPTION

DOE eliminated 4 technologies that were identified in the technology assessment because they have no effect on or do not increase annual fuel utilization efficiency (AFUE) as measured by the DOE test procedure at Appendix N to Subpart B of 10 CFR Part 430. However, these features (*i.e.*, micro combined heat and power, improved motor efficiency, positive shut-off valve for oil burner nozzles, and heat pump boilers) can reduce the energy consumption of the residential boilers in actual applications. Although these technologies were not considered in the analyses, DOE does not discourage their use by manufacturers because of their potential to reduce annual energy consumption. For each technology removed for this reason, DOE provided an explanation of why the technology does not affect AFUE.

4.2.1 Micro Combined Heat and Power (Micro-CHP)

It is possible to use the heat generated by the boiler's combustion system to generate electricity opportunistically. Self-generated electricity can be used to operate the electrical components of the boiler or can be sold back to the grid. Known methods of micro-CHP include fuel cell generators, thermophotovoltaic generators, thermoelectric generators, and thermionic conversion. Other techniques use engines based on the Rankine cycle, Brayton cycle, Stirling cycle, or Otto cycle, where the engine drives an electrical generator or provides direct mechanical power and the waste heat from the engine is used for space heating. Neither the boiler's electricity use nor the heat generated by its electrical components, however, contribute to the calculation of AFUE. Therefore, this technology will have no effect on AFUE.

4.2.2 Improved Motor Efficiency

More-efficient electric motors could be used in hot-water boiler pumps and draft inducers. Most hot-water boiler pumps use a permanent split capacitor (PSC) design. PSC motors are reasonably efficient (above 70 percent) when operating at high speed; however, when these motors are operated at low speed, their efficiencies may drop into the 20 percent range. Energy consumed by the pump or other electrical components, such as draft inducers, is not accounted for by the AFUE calculation.

4.2.3 Positive Shut-Off Valve for Oil Burner Nozzles

One option for oil-fired boilers is a positive shut-off valve on the fuel nozzle, which reduces smoke and soot production during burner start-up and shutdown. This valve is generally installed directly in the nozzle tip and prevents oil from dripping into the combustion chamber. This option can also be retrofitted on existing burners. A positive shut-off valve in an oil burner nozzle does not affect the efficiency of the appliance, but plays a role as an emission-control device.

4.2.4 Heat Pump Boilers

Heat pump boilers use heat pump technology to extract heat from a surrounding source for heating the boiler hot water. For electric boilers, this is an alternative to using electric resistance elements for heating. Since heat does not naturally transfer from a low temperature to a higher temperature, a mechanical system consisting primarily of a closed refrigeration loop containing a refrigerant vapor compressor, an evaporator (a type of heat exchanger), a condenser (another heat exchanger), and an expansion device is used to transfer the heat. The working fluid in the loop, the refrigerant, transfers heat from the heat source (typically the ambient air) to the boiler water. Typically, the evaporator captures heat from the ambient air, and the condenser delivers this heat to the water inside of the boiler. The pump and expansion device facilitate pressure and phase changes to allow for these heat transfer processes. This technology does not improve AFUE, as the test procedure currently sets the AFUE at 100% for indoor electric boilers. Gas-fired absorption heat pumps also use a refrigeration loop to transfer heat to the water, and operate similarly to electric heat pumps except that the compressor is replaced with an absorption cycle. Similarly, this technology does not improve AFUE as it is not captured by the test method.

4.3 SCREENED OUT TECHNOLOGIES

This section describes the technologies that DOE eliminated for failure to meet one of the following four factors: (1) technological feasibility; (2) practicability to manufacture, install, and service; (3) impacts on product utility or product availability; and (4) adverse impacts on health or safety. DOE eliminated pulse combustion, control relays for brushless permanent magnet motors, and burner derating.

4.3.1 Pulse Combustion

Pulse combustion burners operate on self-sustaining resonating pressure waves that alternately rarefy the combustion chamber (drawing a fresh fuel-air mixture into the chamber) and pressurize it (causing ignition by compression heating of the mixture to its flash point). Pulse combustion systems feature high heat transfer rates, and have high combustion efficiency. However, manufacturers have indicated that pulse combustion boilers have had reliability issues in the past, and therefore, they do not consider this as a viable option to improve efficiency. Further, manufacturers indicated that similar or greater efficiencies to those in pulse combustion boilers can be achieved using alternative technologies. For these reasons, DOE is not including pulse combustion as a technology option as it would reduce customer utility.

4.3.2 Burner Derating

Burner derating reduces the burner firing rate while keeping heat exchanger geometry and surface area and the fuel-air ratio the same, which increases the ratio of heat transfer surface area to energy input, and increases efficiency. However, the lower energy input means that less heat is provided than with conventional burner firing rates, which reduces consumer utility. As a result of the decreased heat output of boilers with derated burners, DOE has screened out burner derating as a technology option as it would reduce customer utility

4.3.3 Control Relay for Models with Brushless Permanent Magnet (BPM) Motors (Standby/Off Mode)

During testing of standby and off mode components performed for the DOE furnace and central air conditioner rulemaking,[a] DOE found that BPM motors and their associated controls consume power while in standby and/or off modes, while PSC motors did not have any standby or off mode power draw. Therefore, for those boilers that utilize them, the BPM motor and associated controls could be disconnected while the system is in standby mode or off mode through the use of a control relay to further reduce a system's standby/off mode power consumption. A typical control relay activates a switch when current runs through it and when there is no current a spring holds the switch in the open position. However, manufacturer feedback in the furnace rulemaking (which was reconfirmed during interviews for the boiler rulemaking) indicated that ECM motors are subjected to large currents upon start up and using a control relay to completely depower them could reduce the lifetime of the motors, leading to a reduction in utility of the product. Manufacturer feedback at the framework public meeting also indicated that this feature would reduce the lifetime of the motors. For this reason, DOE is not including control relays as a technology option.

4.4 REMAINING TECHNOLOGIES

After eliminating those technologies that have no effect on improving the rated AFUE or reducing the standby mode and off mode energy consumption, and screening the other technologies using the four criteria listed above, DOE passed the remaining technologies to the engineering analysis for consideration in developing the cost-efficiency relationship.

4.4.1 AFUE Efficiency Standards

For its AFUE standards analysis, DOE considered the following technology options:

- Heat Exchanger Improvements
- Modulating Operation
- Direct Vent
- Delayed Action Oil Pump Solenoid Valve
- Premix Burners
- Low Pressure Air Atomizing Oil Burner

DOE also considered dampers and electronic ignition, but found that they are already incorporated in baseline products.

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[a] For more information see: http://www1.eere.energy.gov/buildings/appliance_standards/residential/residential_furnaces_cac_hp_final_rule.html

4.4.2 Standby Mode and Off Mode Power Consumption Standards

Because DOE is required by EPCA, as amended by EISA 2007, to include a descriptor for standby mode and off mode energy consumption for residential boilers, a separate screening analysis was conducted for standby and off mode design options. (42 U.S.C. 6295(gg)(2)(A))

DOE considered the following design options that are capable of reducing the standby and off mode electrical power consumption of residential boilers:

- Transformer Improvements
- Switching Mode Power Supply

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CHAPTER 5. ENGINEERING ANALYSIS

5.1 INTRODUCTION

The engineering analysis establishes the relationship between the manufacturer production cost (MPC) and the energy efficiency (*i.e.*, annual fuel utilization efficiency (AFUE)) of residential boilers. The relationship between the MPC and energy efficiency, or cost–efficiency relationship, serves as the basis for subsequent cost–benefit calculations for individual consumers, manufacturers, and the Nation.

The primary inputs to the engineering analysis are data from the market and technology assessment (chapter 3 of the technical support document, TSD), input from manufacturers, baseline specifications, and production cost estimates developed using a cost model. The primary output of the engineering analysis is a set of cost-efficiency relationships that represent the average incremental cost of increasing product efficiency above the baseline levels. In the subsequent markups analysis (chapter 6 of the TSD), the U.S. Department of Energy (DOE) determines customer prices by applying distribution markups, sales tax, and contractor markups to the manufacturer sales prices (MSPs) developed in the engineering analysis. After applying these markups, the data serve as inputs to the energy use characterization (chapter 7 of the TSD) and the life-cycle cost and payback period analyses (chapter 8 in the TSD).

DOE typically structures its engineering analysis around one of three methodologies. These are: (1) the design-option approach, which calculates the incremental costs of adding specific design options to a baseline model; (2) the efficiency-level approach, which calculates the relative costs of achieving increases in energy efficiency levels, without regard to the particular design options used to achieve such increases; and/or (3) the reverse engineering or cost-assessment approach, which involves a "bottom-up" manufacturing cost assessment based on a detailed bill of materials derived from teardowns of the product being analyzed. Deciding which methodology to use for the engineering analysis depends on the product, the design options under study, and any historical data that DOE can draw on.

DOE conducted this engineering analysis for AFUE efficiency levels of residential boilers using a combination of the efficiency level and cost-assessment approaches. More specifically, DOE identified the efficiency levels for analysis and then used the cost-assessment approach to determine the manufacturing costs at those levels. Although manufacturers have varied designs, DOE found that the pathway for improving energy efficiency was relatively homogeneous, and as a result, has identified the technologies incorporated at each efficiency level that drive the cost and efficiency changes.

For the standby mode and off mode analyses, DOE adopted a design-option approach, which allowed for the calculation of incremental costs through the addition of specific design options to the baseline model.

5.2 PRODUCT CLASSES CONSIDERED

As noted in the market and technology assessment (chapter 3 in the TSD), DOE has chosen to maintain the existing product classes for residential boilers in the analysis. 10 CFR 430.32(e)(2) The current product classes are divided by the type of energy used (fuel type) and by the heat transfer medium (*i.e.*, steam or hot water) as shown in Table 5.2.1. DOE has determined that heat transfer medium is a performance-related characteristic that merits a separate product class due to the significantly different efficiency and performance characteristics of hot water and steam boilers. In the analysis, DOE maintained the product classes established by the Energy Independence and Security Act of 2007 (EISA 2007).

Table 5.2.1 Product Classes Considered for Standby Mode and Off Mode

Fuel Type	Heat Transfer Medium
Gas	Steam
	Hot Water
Oil	Steam
	Hot Water
Electric	Steam
	Hot Water

As Table 5.2.2 shows, DOE has not included electric boilers in the final rule analysis of amended AFUE standards. However, DOE has considered standby mode and off mode electrical consumption standards for electric boilers in the analysis. DOE also did not separately analyze combination appliances that provide both space heating and domestic hot water to a residence in this analysis.

Table 5.2.2 Product Classes Considered for AFUE Standards

Fuel Type	Heat Transfer Medium
Gas	Steam
	Hot Water
Oil	Steam
	Hot Water

5.3 METHODOLOGY OVERVIEW

This section describes the analytical methodology used in the engineering analysis. Figure 5.3.1 shows a flow diagram of this methodology and the corresponding sections in this chapter. The results of the engineering analysis are cost-efficiency curves for each representative product

class.

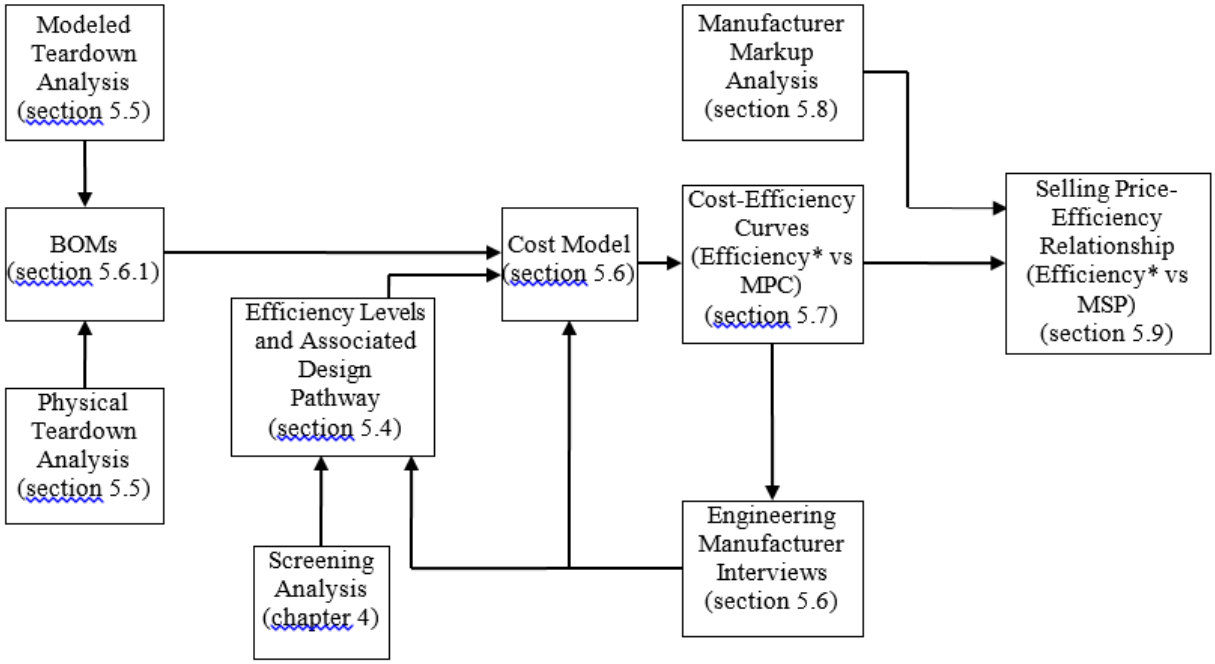

Figure 5.3.1 Flow Diagram of Engineering Analysis Methodology

DOE started by identifying in the market assessment (chapter 3 of this TSD) residential boilers available on the market and the energy efficiency level associated with each. DOE also identified the technologies and features typically incorporated into products at the baseline level and various energy efficiency levels above the baseline. DOE gathered the information from the physical and virtual teardown analysis to create bills of materials (BOMs) for each product using reverse engineering methods (section 5.5). DOE converted the information recorded in the BOMs to dollar values using a cost model computer program to calculate the MPC for products spanning the full range of efficiencies from the baseline to the maximum technology available. DOE also identified the technology or combination of technologies mainly responsible for improving the energy efficiency of residential boilers, as DOE found that the use of these technologies was relatively similar across manufacturers.

During the preparation of the cost efficiency comparison and MPCs, DOE interviewed manufacturers to gain insight into the residential boiler industry and request input on the engineering approach and estimates DOE used for the analysis. DOE used the information gathered from these interviews to refine efficiency levels and potential technology pathways, as well as assumptions in the cost model. DOE converted the MPCs into manufacturer selling prices (MSPs, section 5.10) using publicly available industry financial data, along with

manufacturer feedback.

The methodology used for the standby mode and off mode engineering analysis started with determining the energy use of baseline products. DOE adopted a design-option approach, which allowed for the calculation of incremental costs through the addition of specific design options to a baseline model. DOE decided on this approach because it did not have sufficient data to execute an efficiency-level analysis, as manufacturers typically do not rate or publish data on the standby mode and/or off mode energy consumption of their products. Because standby mode and off mode electricity consumption is not currently regulated, manufacturers generally do not invest in reducing the standby and off mode electrical energy consumption of their products; this is likely because the production cost cannot be passed onto the consumer as consumers do not value this feature enough to pay extra for it. Therefore, DOE determined that there is no basis for comparison of efficiency levels between products. The design-option approach, by contrast, allowed DOE to examine potential designs for improving the off mode energy consumption.

5.4 EFFICIENCY LEVELS

For the majority of the product classes presented in section 5.2, DOE analyzed multiple efficiency levels and estimated the manufacturer production costs at each of these levels. The following subsections provide the full efficiency level range from the baseline efficiency level to the maximum technology feasible efficiency level for each product class. DOE notes that in all cases the highest efficiency level was identified through review of available product literature for commercially available products. In addition, this section contains a brief description of the design options that are generally found in products at each efficiency level, as DOE found that the designs utilized were similar across manufacturers.

5.4.1 Baseline Unit

DOE selected baseline units as reference points for each product class, against which DOE measured changes resulting from potential amended energy conservation standards. The baseline unit in each product class represents the basic characteristics of products in that class. Typically, a baseline unit is a unit that just meets current federal energy conservation standards and provides basic consumer utility. DOE uses the baseline unit for comparison in several phases of the analyses, including the engineering analysis, lifecycle cost (LCC) analysis, payback period (PBP) analysis, and national impacts analysis (NIA). To determine energy savings that will result from an amended energy conservation standard, DOE compares energy use at each of the higher energy efficiency levels to the energy consumption of the baseline unit. Similarly, to determine the changes in price to the consumer that will result from an amended energy conservation standard, DOE compares the price of a baseline unit to the price of a unit at each higher efficiency level.

Table 5.4.1 presents the baseline AFUE energy efficiency levels for each considered product class as well as some common characteristics of these baseline residential boilers.

Table 5.4.1 Baseline AFUE Energy Efficiency Levels and Features for Residential Boilers

Product Class	AFUE %	Input Capacity *btu/hr*	Heat Exchanger	Draft	Design Requirements
Gas Hot Water	82	100,000	Sectional, dry-base cast iron or copper-tube	-Natural draft -Draft hood (4.7.1) or draft diverter (4.7.2) -Stack damper (4.8.1)	No constant burning pilot, automatic means for adjusting water temperature
Gas Steam	80	100,000	Sectional, dry-base cast iron	-Natural draft -Draft hood (4.7.1) or draft diverter (4.7.2) -Stack damper (4.8.1)	No constant burning pilot
Oil Hot Water	84	140,000	Sectional, wet-base cast iron	-Power burner natural draft (4.5.2.1) - Barometric regulator (4.7.3)	Automatic means for adjusting temperature
Oil Steam	82	140,000	Sectional, wet-base cast iron	-Power burner Natural draft (4.5.2.1) - Barometric regulator (4.7.3)	None

The design-option approach calculates the incremental cost for products with standby or off mode energy consumption above a baseline model in each product class covered in the rulemaking. In most rulemakings, the baseline is determined by the current federal energy conservation standard. However, because this is the first rulemaking to regulate the standby and off mode energy consumption of residential boilers, DOE instead established the baseline model for the standby mode and off mode analysis as the most energy-consumptive product. DOE defined and identified baseline components as those that consume the most electricity during standby mode and off mode operation. The most consumptive baseline components were then "assembled" to model the electrical system of a boiler with the maximum system off mode electrical energy consumption from DOE's representative test data.

DOE identified components that contribute to the standby mode and off mode energy consumption in the teardown-generated BOM used for the boilers that were analyzed. During the 2010 furnace and central air conditioner rulemaking, DOE performed measurements of standby mode and off mode electrical energy consumption on each of these components in accordance with the test procedure for furnaces and boilers, which is identical for both products. DOE aggregated these measurements, in conjunction with nominal power ratings and feedback from manufacturers regarding individual component's power draw, to characterize the electrical

energy use of each component operating in standby mode or off mode. Certain electrical components in residential furnaces are similar to those found in residential boilers. In the initial analysis DOE assumed the measured power consumption from the furnace rulemaking would be representative of the component standby consumption of boilers in the analysis. DOE than estimated the costs of individual components based on available literature,[1] volume-variable price quotations and detailed discussions with manufacturers.

DOE tested the standby mode and off mode energy consumption of fourteen boiler models across the various product classes to inform the component analysis. The most consumptive baseline components were then "assembled" to model the electrical system of a boiler with the maximum system off mode electrical energy consumption from DOE's representative test data. The baseline gas-fired hot water boiler model contains a 40VA control transformer, user display, electronically commutated motor (ECM) burner motor (and associated controls), and linear power supply. For oil-fired boilers only, the baseline model also included an oil-fired burner that contains an additional transformer that consumes additional standby power. DOE maintained the baseline power consumption levels analyzed in the NOPR in the final rule analysis. The baseline standby mode and off mode levels are presented in Table 5.4.2.

Table 5.4.2 Baseline Standby Mode and Off Mode Power Consumption by Component for Boilers

Component	Standby Mode and Off Mode Power Consumption watts					
	Gas Hot Water	Oil Hot Water	Gas-Fired Steam	Oil-Fired Steam	Electric Hot Water	Electric Steam
Transformer	4	4	4	4	4	4
ECM Burner Motor	1	N/A	N/A	N/A	N/A	N/A
Controls	2.5	2.5	2.5	2.5	2.5	2.5
Display	4	4	4	4	4	4
Oil Burner	N/A	3	N/A	3	N/A	N/A
Total (watts)	11.5	13.5	10.5	13.5	10.5	10.5

DOE analyzed the expected standby mode and off mode power consumption of electric boilers by comparing their components that consume power in standby mode and off mode to the standby mode and off mode power consumption of gas boilers. In electric boilers, DOE found that the same components primarily contribute to standby mode and off mode power consumption in the baseline design (*i.e.*, the control transformer and the control board power supply).

To estimate the standby mode and off mode power consumption of electric boilers, DOE compared wiring diagrams, control schematics, and images of control boards of gas and electric boilers. DOE found that electric boilers commonly use a 40VA transformer that is very similar to those found in gas boilers. For the analysis of standby mode and off mode for

electric boilers, DOE assumed that the power consumption associated with these transformers would be the same. Further, a DOE review of electric boilers found that other components are also the same as or very similar to those used in gas boilers. Therefore, DOE assumed the standby consumption for these components would be the same in electric boilers as in gas boilers. A key difference between electric boilers and gas boilers control systems is that electric boilers control boards tend to be less complex because they do not require functions such as flame ignition and supervision or other combustion safety controls. However, electric boilers control boards must use relays and/or sequencers that have higher capacity ratings than the relays typically found in gas boilers to turn the electric heating elements on incrementally. The elements must be activated individually to limit inrush currents and prevent trips of circuit breakers. DOE estimates that the additional standby mode and off mode power consumption associated with the use of larger relays and/or sequencers in electric boilers is offset by need for combustion controls in gas boilers.

As a result, DOE assumed that an electric boiler has a standby mode and off mode electrical consumption similar to that of a gas boiler in similar models, with the exception that electric boilers do not utilize ECM burner motors and therefore have slightly less standby. In addition, the design options that were identified for reducing the standby mode and off mode power consumption of gas boilers (*i.e.*, a switching mode power supply and a low loss transformer) will have the same impact on the standby mode and off mode power consumption of electric boilers. Therefore, DOE analyzed standby mode and off mode standards for electric boilers based on the standby mode and off mode analysis of gas boilers.

5.4.2 Design Options

Although the screening analysis (chapter 4) provided viable design options for improving residential boilers, DOE did not consider all technologies that passed the screening analysis in the engineering analysis. Based on information gathered from the teardown analysis, manufacturer interviews, and publicly available product literature, DOE determined which design options manufacturers incorporate into products and at which efficiency levels those design options are typically implemented. DOE also determined which design options manufacturers are most likely to include in future products, and used these design options in developing the product costs at each efficiency level. Although several design options are not included in the engineering analysis, DOE acknowledges that these still may be viable methods to improve the efficiency of residential boilers. Table 5.4.3 lists the design options that DOE did not screen out in the screening analysis and which are included in the AFUE engineering analysis.

Table 5.4.3 Design Options Considered for the AFUE Engineering Analysis for Residential Boilers

Technology Section	Technology	Gas-Fired Hot Water	Gas-Fired Steam	Oil-Fired Hot Water	Oil-Fired Steam
Heat Exchanger Improvements	Condensing	X		X	
	Improved/increased heat exchanger surface area	X	X	X	X
	Baffles	X	X	X	X
Burner	Modulation	X		X	

For the standby and off mode analysis, DOE implemented design options based on cost-effectiveness until all available technologies were employed (*i.e.*, at the max-tech level). The design options considered are not all mutually exclusive, so systems could incorporate multiple design options simultaneously. This allows for three system designs above the baseline. The design options included: changing from a baseline linear power supply with standard transformer to a linear power supply with a low loss transformer (LLTX), changing to a switching mode power supply (SMPS) with a standard transformer, and changing to a SMPS with a LLTX.

5.4.3 Energy Efficiency Levels

DOE conducted a survey of the residential boiler market to determine what types of products are currently available to consumers. For each representative product, DOE surveyed various manufacturers' product offerings as well as the DOE database to identify the efficiency levels that correspond to the highest number of models. By identifying the most prevalent energy efficiencies in the range of available products and the designs of those products, DOE was able to establish a technology path that manufacturers would typically use to increase the energy efficiency of residential boilers.

DOE established intermediate energy efficiency levels for each product class. The intermediate efficiency levels are representative of efficiency levels along the technology paths that manufacturers of residential boilers commonly use to maintain cost-effective designs while increasing energy efficiency. DOE reviewed its database of residential boilers, manufacturer catalogs, and other publicly available literature to determine which efficiency levels are the most prevalent for each representative product class. Table 5.4.4 through Table 5.4.7 list the product classes and their respective intermediate energy efficiency levels.

For gas-fired hot water boilers, DOE chose five efficiency levels between the baseline and max tech levels for analysis. In order to increase the efficiency of gas-fired hot water boilers, manufacturers generally improve the heat transfer of the heat exchanger. Manufacturers typically accomplish this by adding baffles or increasing the size of the heat exchanger. Sometimes, because of increased pressure in the heat exchanger resulting from tighter air passages and/or the addition of baffles/turbulators, a fan-assisted draft system is incorporated. Max tech gas-fired hot water boilers include corrosion resistant heat exchangers (HX) that condense the flue gases in

order to extract the greatest amount of heat. Table 5.4.4 shows the efficiency levels analyzed for gas-fired hot water boilers along with the associated technology options.

Table 5.4.4 AFUE Efficiency Levels for Analysis for Gas-Fired Hot Water Boilers

Efficiency Level	Gas-Fired HW AFUE, %	Technology Options
0 (Baseline)	82	Baseline
1	83	EL0+ Increased HX area, baffles
2	84	EL1+ Increased HX area
3	85	EL2+ Increased HX area
4	90	Condensing HX, modulating
5	92	EL4+ Improved HX
6 (max tech)	96	EL5+ Improved HX

For gas-fired steam boilers, DOE chose one efficiency level between the baseline and max tech for analysis. To increase the efficiency of gas-fired steam boilers, manufacturers generally improve the heat transfer of the heat exchanger. Manufacturers accomplish this through increasing the size of the heat exchanger. Table 5.4.5 shows the design options associated with each efficiency level for the representative product.

Table 5.4.5 AFUE Efficiency Levels for Analysis for Gas-Fired Steam Boilers

Efficiency Level	Gas-Fired Steam AFUE, %	Technology Options
0 (Baseline)	80	Baseline
1	82	EL0+ Increased HX area
2 (max tech)	83	EL1+ Increased HX area

For oil-fired hot water boilers, DOE chose two efficiency levels between the baseline and max tech for analysis. To increase the efficiency of oil-fired hot water boilers, manufacturers generally improve the heat transfer of the heat exchanger by increasing the size of the heat exchanger. Finally, at the max tech oil-fired hot water boiler, manufacturers use an improved heat exchanger design and also include a secondary heat exchanger that condenses the flue gases in order to extract the greatest amount of heat. Table 5.4.6 shows the design options associated with each efficiency level for the representative product.

Table 5.4.6 AFUE Efficiency Levels for Analysis for Oil-Fired Hot Water Boilers

Efficiency Level	Oil-Fired HW AFUE, %	Technology Options
0 (Baseline)	84	Baseline
1	85	EL0+ Increased HX area
2	86	EL1+ Increased HX area
3 (max tech)	91	EL2+ Improved HX and secondary condensing HX

For oil-fired steam boilers, DOE chose two efficiency levels between the baseline and max tech for analysis. To increase the efficiency of oil-fired steam boilers, manufacturers generally improve the heat transfer of the heat exchanger. Manufacturers accomplish this by increasing the size of the heat exchanger or by making the heat exchanger more restrictive. Table 5.4.7 shows the design options associated with each efficiency level for the representative product.

Table 5.4.7 AFUE Efficiency Levels for Analysis for Oil-fired Steam Boilers

Efficiency Level	Oil-Fired Steam AFUE, %	Technology Options
0 (Baseline)	82	Baseline
1	84	EL0+ Increased HX area
2	85	EL1+ Increased HX area
3 (max tech)	86	EL2+ Improved HX

For the standby mode and off mode analysis, DOE used the design option approach. This allowed for the calculation of incremental costs through the addition of specific design options to a baseline model. The first design option (EL1) is the change from a standard transformer to a low-loss transformer (LLTX). The second design option (EL2) is the change from a linear power supply to a switching mode power supply. The third design option (EL3) is a switching mode power supply with a LLTX to power the thermostat.

Table 5.4.8 through Table 5.4.13 shows each of the product classes examined and their respective intermediate energy efficiency levels.

Table 5.4.8 Standby and Off Mode Efficiency Levels for Gas Hot Water Boiler

Efficiency Level	Description	Standby Mode and Off Mode Power Consumption W
Baseline	Linear power supply	11.5
1	Linear power supply with LLTX	10.0
2	Switching mode power supply	9.7
3	Switching mode power supply with LLTX	9.0

Table 5.4.9 Standby and Off Mode Efficiency Levels for Oil Hot Water Boiler

Efficiency Level	Description	Standby Mode and Off Mode Power Consumption W
Baseline	Linear power supply	13.5
1	Linear power supply with LLTX	12.0
2	Switching mode power supply	11.7
3	Switching mode power supply with LLTX	11.0

Table 5.4.10 Standby and Off Mode Efficiency Levels for Gas Steam Boilers

Efficiency Level	Description	Standby Mode and Off Mode Power Consumption W
Baseline	Linear power supply	10.5
1	Linear power supply with LLTX	9.0
2	Switching mode power supply	8.7
3	Switching mode power supply with LLTX	8.0

Table 5.4.11 Standby and Off Mode Efficiency Levels for Oil Steam Boilers

Efficiency Level	Description	Standby Mode and Off Mode Power Consumption W
Baseline	Linear power supply	13.5
1	Linear power supply with LLTX	12.0
2	Switching mode power supply	11.7
3	Switching mode power supply with LLTX	11.0

Table 5.4.12 Standby and Off Mode Efficiency Levels for Electric Hot Water Boilers

Efficiency Level	Description	Standby Mode and Off Mode Power Consumption W
Baseline	Linear power supply	10.5
1	Linear power supply with LLTX	9.0
2	Switching mode power supply	8.7
3	Switching mode power supply with LLTX	8.0

Table 5.4.13 Standby and Off Mode Efficiency Levels for Electric Steam Boilers

Efficiency Level	Description	Standby Mode and Off Mode Power Consumption W
Baseline	Linear power supply	10.5
1	Linear power supply with LLTX	9.0
2	Switching mode power supply	8.7
3	Switching mode power supply with LLTX	8.0

5.4.4 Max Tech Efficiency Levels

As part of the engineering analysis, DOE determined the maximum technologically feasible improvement in energy efficiency for residential boilers as required by section 325(o) of EPCA. (42 U.S.C. 6295(o)) DOE conducted a survey of the residential boiler market and the research fields that support the market. Table 5.4.14 lists the max tech levels DOE determined for the AFUE engineering analysis for residential boilers.

Table 5.4.14 Max Tech AFUE Efficiency Levels for Residential Boilers

Product Class	Maximum AFUE %
Gas Hot Water	96
Gas Steam	83
Oil Hot Water	91
Oil Steam	86

5.5 TEARDOWN ANALYSIS

To assemble BOMs and calculate the manufacturing costs of the different components in residential boilers, DOE disassembled multiple residential boilers into their components and estimated the material and labor cost of each component. This process is referred to as a "physical teardown." A supplementary method, called a "virtual teardown," uses published manufacturer catalogs and supplementary component data to estimate the major physical differences between a product that was physically disassembled and a similar product that was not. The teardown analysis included 20 teardowns of residential boilers.

5.5.1 Selection of Units

When selecting units for teardowns, DOE considered three main questions:

1. What efficiency levels should be captured in the teardown analysis?
2. Are there units on the market that capture the range potential efficiency levels?
3. Which of the available units are most representative?

In responding to these questions, DOE adopted the following criteria for selecting units for the teardown analysis:

1. The selected products should span the full range of efficiency levels for each product class under consideration.
2. If possible, the selected products within each product class should come from the same manufacturer and be within the same product series.
3. The selected products should come primarily from manufacturers with large market share in that product class, although the highest efficiency products were chosen irrespective of manufacturer.

The selected products should have non-efficiency-related features that are the same or similar to features of other products in the same class and for a range of efficiency levels. DOE surveyed the residential boiler industry and identified products available to consumers. DOE then applied the aforementioned criteria and selected baseline, intermediate, and max tech units that met the product descriptions, energy efficiency levels, and included the technologies identified in the market survey. In several cases, DOE substituted a virtual teardown in the place of a physical teardown. For example, if two boiler models differed only by an extra heat exchanger section, one was physically torn down and the additional material and manufacturing cost due to the additional section (*e.g.,* for the extra sheet metal if the overall cabinet size increased, and for the additional section) was added to the cost of the physically torn down model to determine the MPC of the virtually torn down model.

The teardown analysis of residential boilers included sixteen physical teardowns and four additional virtual teardowns. DOE identified and selected representative units across the entire range of efficiencies that are currently available to consumers. To the extent possible, all major efficiency levels and technologies were captured in the selection of models for teardown analysis.

DOE selected the majority of the physical teardown units in the gas hot water product class because it has the largest number of shipments. DOE conducted physical teardowns of twelve gas hot water boilers, five of which were non-condensing cast iron boilers, two were non-condensing copper boilers, and the remaining five were condensing boilers. DOE performed an additional two virtual teardowns of gas hot water boilers.

DOE also performed physical teardowns on two gas-fired steam boilers as well as two oil-fired hot water boilers. DOE conducted one virtual teardown of an oil steam boiler as well as a virtual teardown of an oil hot water boiler.

5.5.2 Baseline Units

DOE selected baseline units for the teardown analysis to determine which technologies manufacturers incorporate into products to obtain energy efficiencies equal to the current federal energy conservation standards. Typically, the baseline units are representative of the minimum technology and lowest cost product that manufacturers can produce. DOE compared the technology and cost of products at the baseline to those at higher energy efficiency levels. The efficiencies of the baseline units are described in section 5.4.1.

DOE gathered information from the physical and virtual teardowns as well as from published data to determine which features manufacturers incorporate into baseline units. Generally, baseline boiler models have cast iron heat exchangers, are natural draft with dampers;

water boilers have pumps driven by a standard permanent split capacity (PSC) induction motor.

5.6 COST MODEL

5.6.1 Generation of Bills of Materials

The result of each teardown is a structured BOM, which describes each product part and its relationship to the other parts in the estimated order in which manufacturers assembled them. The BOMs describe each fabrication and assembly operation in detail, including the type of equipment needed (*e.g.*, presses, drills), process cycle times, and labor associated with each manufacturing step. The result is a thorough and explicit model of the production process, including space, conveyor, and equipment requirements by planned production level. DOE developed structured BOMs for each of the physical and virtual teardowns.

The BOMs incorporate all materials, components, and fasteners classified as either raw materials or purchased parts and assemblies. The designations as raw materials or purchased parts were based on DOE's previous industry experience, recent information in trade publications, and discussions with original equipment manufacturers (OEMs). DOE also visited manufacturing plants to reinforce its understanding of the industry's current manufacturing practices for residential boilers.

The price of purchased parts is estimated based on volume variable price quotations and detailed discussions with manufacturers and component suppliers. For fabricated parts, the prices of raw materials are estimated on the basis of 5-year averages (Jan. 2010- Dec. 2014) (section 5.6.4.3). The cost of transforming the intermediate materials into finished parts is estimated based on current industry pricing. DOE shared major estimates with manufacturers during manufacturer interviews to gain feedback on its analysis, assumptions, methodology, and initial results.

5.6.2 Structure of Spreadsheet Cost Model

DOE uses a detailed, component focused technique for calculating the manufacturing cost of a product (direct materials, direct labor, and the overhead costs associated with production). The first step in the manufacturing cost assessment is to create a complete and structured BOM by disassembling the units selected for teardown. The units were dismantled, and each part was characterized according to weight, manufacturing processes, dimensions, material, and quantity. The BOM incorporates all materials, components, and fasteners, as well as estimates of raw material and purchased part costs. Assumptions on the sourcing of parts and in-house fabrication were based on industry experience, information in trade publications, and discussions with manufacturers. Interviews with manufacturers and plant visits added industry experience for the methodology and pricing.

After generating the BOMs from the teardown analysis, the final step was to convert this information into dollar values. DOE collected information on labor rates, tooling costs, raw material prices, and other factors. DOE assumed values for these parameters using internal

expertise and confidential information available to DOE contractors. Although most of the assumptions are manufacturer specific and cannot be revealed due to confidentiality concerns, section 5.6.4.3 provides a discussion of the values used for each assumption.

DOE assigned costs of labor, materials, and overhead to each part, whether purchased or produced in house. DOE then aggregated single-part costs into major assemblies and summarized these costs in a worksheet. During engineering interviews with manufacturers, DOE shared key estimates from the cost model and requested feedback. DOE considered all relevant information manufacturers gave and incorporated it into the analysis as appropriate.

5.6.3 Cost Model and Definitions

Once DOE disassembled selected units, gathered information from manufacturer catalogs on additional products, and identified technologies, DOE created a manufacturing cost model to translate physical information into MPCs. The cost model is based on production activities and divides factory costs into the following categories:

- Materials: Purchased parts (*e.g.*, gas valves, ignition modules), raw materials (*e.g.*, cold rolled steel, copper tube), and indirect materials used for processing and fabrication.
- Labor: Fabrication, assembly, indirect, and supervisor labor. Fabrication and assembly labor cost are burdened with benefits and supervisory costs.
- Overhead: Equipment, tooling, and building depreciation, as well as utilities, equipment and tooling maintenance, insurance, and property taxes.

5.6.3.1 Cost Definitions

Because there are many different accounting systems and methods to monitor costs, DOE defined the above terms as follows:

- Direct material: Purchased parts (outsourced) plus manufactured parts (made in house from raw materials).
- Indirect material: Material used during manufacturing (*e.g.*, welding rods, adhesives).
- Fabrication labor: Labor associated with in house piece manufacturing.
- Assembly labor: Labor associated with final assembly.
- Indirect labor: Labor costs that scaled with fabrication and assembly labor. This included the cost of technicians, manufacturing engineering support, stocking, etc., that were assigned on a span basis.
- Equipment and plant depreciation: Money allocated to pay for initial equipment installation and replacement as the production equipment wears out.
- Tooling depreciation: Cost for initial tooling (including nonrecurring engineering and debugging of the tools) and tooling replacement as it wears out.
- Building depreciation: Money allocated to pay for the building space and the conveyors that feed and/or make up the assembly line.
- Utilities: Electricity, gas, telephones, etc.

- Maintenance: Money spent on maintaining tooling and equipment.
- Insurance: Appropriated as a function of unit cost.
- Property Tax: Appropriated as a function as unit cost.

5.6.4 Cost Model Assumptions Overview

As discussed in the previous section, assumptions about manufacturer practices and cost structure played an important role in estimating the final product cost. Assumptions varied for specific manufacturers, depending on market position, manufacturing practices, and size.

In converting physical information about the product into cost information, DOE reconstructed manufacturing processes for each component using internal expertise and knowledge of the methods used by the industry. DOE used assumptions about manufacturing process parameters (*e.g.*, equipment use, labor rates, tooling depreciation, and cost of purchased raw materials) to determine the value of each component. DOE then summed the values of the components into assembly costs and finally, the total product cost. The product cost included the material, labor, and overhead costs associated with the manufacturing facility. The material costs included both direct and indirect materials. The labor costs included fabrication, assembly, indirect, direct, and supervisor labor rates, including the associated overhead.

DOE determined labor costs by the type of product manufactured at the factory. Overhead costs include equipment depreciation, tooling depreciation, building depreciation, utilities, equipment, tooling maintenance, insurance, property, and taxes.

DOE presented a draft of the cost-efficiency results to manufacturers during the interviews, and used information from the interview to update the cost model to address component and material pricing and production volumes. When appropriate, DOE modified the cost model immediately after an interview so refined data could be presented to the next manufacturer. Positive feedback from manufacturers presented with refined data confirmed the accuracy of the changes.

The next sections discuss assumptions about outsourcing, factory parameters, production volumes, and material prices. When the assumptions are manufacturer specific, they are presented as industry averages to prevent disclosure of confidential information.

5.6.4.1 Fabrication Estimates

DOE characterized parts based on whether manufacturers purchased them from outside suppliers or fabricated them in house. For purchased parts, DOE estimated the purchase price. For fabricated parts, DOE estimated the price of raw materials (*e.g.,* tube, sheet metal) and the cost of transforming them into finished parts. Whenever possible, DOE obtained price quotes directly from the manufacturers' suppliers.

DOE based the manufacturing operations assumptions on internal expertise, interviews with manufacturers, and visits to manufacturing facilities. Table 5.6.1 presents the major manufacturer processes identified and developed for the spreadsheet model.

Table 5.6.1 Cost Model for In-House Manufacturing Operation Assumptions

Fabrication	Finishing	Assembly/Joining	Quality Control
Stamping/Pressing	Washing	Adhesive Bonding	Inspection and Testing
Turret Punch	Painting	Spot Welding	
Tube Forming	Powder Coating	Seam Welding	
Brake Forming	De-Burring	Packaging	
Cutting and Shearing	Polishing		
Insulating			
Casting			

5.6.4.2 Factory Parameters

Certain factory parameters, such as fabrication rates, labor rates, and wages, also affect the cost of each unit produced. DOE factory parameter assumptions were based on internal expertise and manufacture feedback. Table 5.6.2 lists the factory parameter assumptions used in the cost model.

Table 5.6.2 Factory Parameter Assumptions

Parameter	Assumption
Actual Annual Production Volume	20,000 units/year
Work Days Per Year	250 days
Assembly Shifts Per Day	2 shifts
Fabrication Shifts Per Day	2 shifts
Fabrication Labor Wages	16 $/hr
Assembly Labor Wages	16 $/hr
Length of Shift	8 hrs
Average Equipment Installation Cost	10 % of purchase price
Fringe Benefits Ratio	50%
Indirect to Direct Labor Ratio	33%
Average Scrap Recovery Value	30%
Worker Downtime	10%
Building Life	30 years
Burdened Assembly Labor Wage	24 $/hr
Burdened Fabrication Labor Wage	24 $/hr
Supervisor Span	25 workers/supervisor
Supervisor Wage Premium	30% over fabrication and assembly wage

5.6.4.3 Material Prices Assumptions

DOE determined the cost of raw materials using publicly available information such as the *American Metals Market*, interviews with manufacturers, and discussions with material

suppliers. Metals used in the fabrication of residential boilers include cast iron, copper, aluminum, and steel. There have been fluctuations in metal prices over the last few years; to account for these fluctuations, DOE used a 5-year average of metal prices from the Bureau of Labor Statistics Producer Price Indices (PPIs) spanning from January 2010 to December 2014. Table 5.6.3 shows the 5-year average metal prices DOE used for the analysis.

Table 5.6.3 Five-Year Metal Prices (2010-2014)

Metals	Cost $/lb
Cold Rolled Steel (CRS)	0.46
Aluminized CRS	0.56
Galvanized CRS	0.55
Pre-Painted CRS	0.68
Textured CRS	0.68
AL29-4C	8.00
AL29-4C tube	12.26
SS316 Tube	4.32
Plain Cu Tube, ≤ .75” OD	8.76
Plain Cu Tube, > .75” OD	4.26
Rifled Cu Tube, ≤ .75” OD	4.51
Sandcasting Raw Stock	.43
Sandcasting done in USA	.97

5.6.5 Manufacturing Production Cost

Once the cost estimate for each teardown unit was finalized, DOE prepared a detailed summary for relevant components, subassemblies, and processes. The BOM thus details all aspects of unit costs. DOE totaled the cost of materials, labor, and direct overhead used to manufacture a product to calculate the MPC.

Technologies used in the units subject to teardown are noted in the summary sheet of each cost model and the costs are estimated individually. Thus, various implementations of technologies can be accommodated, ranging from assemblies that are entirely purchased to units that are entirely made from raw materials. Therefore, hybrid assemblies, consisting of purchased parts and parts made on site, are also accommodated.

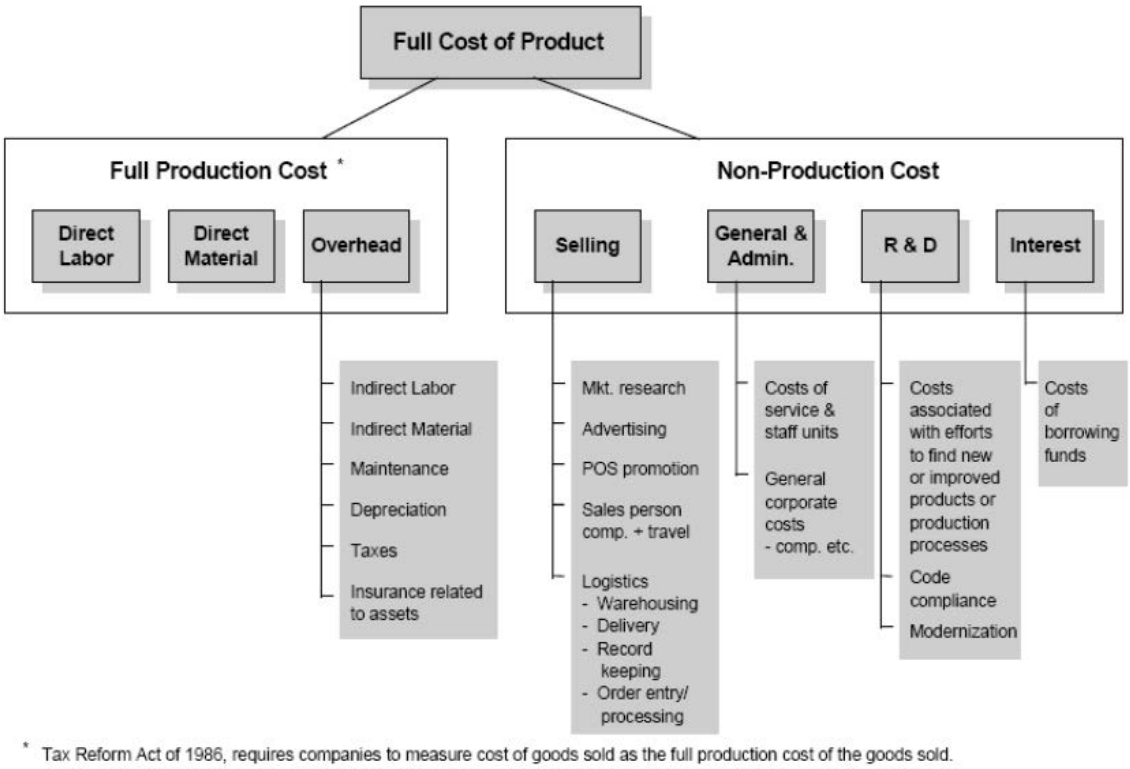

Figure 5.6.1 Breakdown of Costs Associated with Manufacturing a Product

The full cost of the equipment is broken down into two main costs: the full production cost or MPC, and the nonproduction cost. The nonproduction cost is equal to the manufacturer markup minus profits.

Following the development of the MPCs, DOE reviewed its major cost estimates during interviews with residential boiler manufacturers, who provided feedback and validation. As a result, DOE developed MPCs for use in the subsequent analyses.

5.7 COST VERSUS EFFICIENCY CURVES

As described in section 5.5.1, DOE first estimated the MPC of the baseline units for each product class. DOE then determined the intermediate efficiency levels, up to max tech, that represent the residential boiler market, and identified the MPCs for each of these intermediate efficiency levels. The result of the engineering analysis are cost-efficiency curves representing the product classes examined for this analysis.

As noted in section 5.5.1, DOE developed the gas hot water cost-efficiency curve by conducting physical teardowns of twelve gas hot water boilers, five of which were non-condensing cast iron boilers. One of the non-condensing cast iron boilers was at baseline 82 percent AFUE, two were at 84 percent AFUE, and the remaining two were at 85 percent AFUE.

Two physical teardowns were performed on copper boilers, one at baseline 82 percent AFUE and the other at 85 percent AFUE. The remaining five boilers were condensing boilers. Of the condensing boilers, one was at 90 percent AFUE, one at 92 percent AFUE, two were at 95 percent AFUE and one was at 96 percent AFUE. DOE performed virtual teardowns at the 82 percent AFUE and 84 percent AFUE level on models in the same product lines as one of the 85 percent AFUE boilers. To obtain an estimate of the manufacturing cost at 83 percent AFUE, DOE linearly interpolated between the 82 percent AFUE and 84 percent AFUE levels to estimate the size increase of the heat exchanger and associated costs for the increased heat exchanger materials and other associated costs (*e.g.*, larger cabinet).

DOE developed the oil hot water cost-efficiency curve by conducting two physical teardowns of boilers at the 86 percent and 91 percent AFUE levels. DOE performed a virtual teardown at the 84 percent AFUE level. To obtain an estimate of the manufacturer production cost at 85 percent AFUE, DOE linearly interpolated between the 84 percent AFUE and 86 percent AFUE levels to determine the amount of heat exchanger increase and modeled the associated changes in production cost. DOE also included the increase cost in sheet metal for the increased cabinet size.

To determine the increase in production cost for increasing the efficiency from 80 percent AFUE to 82 percent AFUE for gas-fired steam boilers DOE used available information from the hot water product class costs to determine the cost increase in its development of the steam boiler costs. DOE relied on the similarities between hot water and steam boilers, as many steam boilers are similar in design to a corresponding hot water boiler with a somewhat larger heat exchanger and different trim kit. Based on a review of product literature and market data, DOE estimated the efficiency difference between a boiler operating in hot water mode and steam mode. DOE conducted two physical teardowns of gas-fired steam boilers at 82 percent AFUE and 83 percent AFUE. DOE developed the oil-fired steam cost-efficiency curves through a virtual teardown of an 82 percent AFUE oil-fired steam boiler as well as a review of product literature and market data.

Lastly, DOE considered the draft type and whether the model would have fan-assisted draft at a given efficiency level. The cost of adding an inducer includes the cost of the fan assembly and mounting, minus the cost of the damper, which would likely be present on a non-fan-assisted unit but would not be needed on a unit with an inducer fan. During the manufacturer interviews, DOE sought feedback specifically regarding the cost of adding an inducer fan. Based on that feedback, DOE estimated the cost of the inducer fan differential to be $96.97, which includes the cost of the fan assembly and mounting, vent and pressure switch, draft hood and vent connector, minus the cost of a damper.

After determining the cost to add an inducer, DOE surveyed the market and found the percentage of models at each efficiency level that currently utilize a fan-assisted draft. DOE also received manufacturer feedback indicating what percentage of boilers sold include an inducer fan at each efficiency level. DOE applied the cost of adding an inducer at each efficiency level based on the distribution of model shipments with and without fan-assisted draft provided by manufacturer comment. For additional details see chapter 8 of the TSD.

Figure 5.7.1 through Figure 5.7.4 show the four cost-efficiency curves in the form of energy efficiency (*i.e.*, AFUE) versus MPC. The results show that the cost-efficiency curves are nonlinear. As efficiency increases, manufacturing becomes more difficult and more costly for manufacturers. Large increases in costs are evident when hot water boilers are designed for condensing operation. Similarly, large increases in costs are evident as the efficiency of a steam boiler improves.

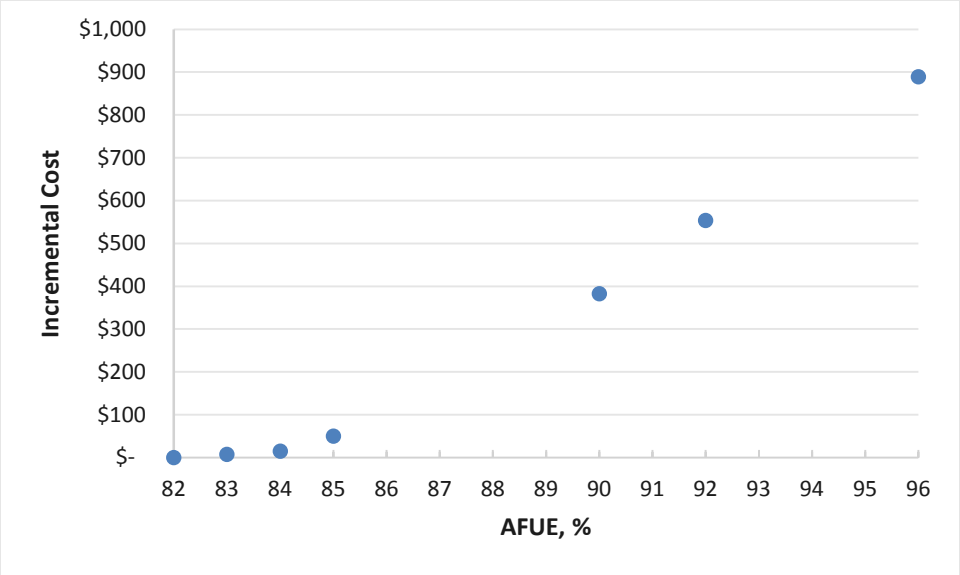

Figure 5.7.1 AFUE Gas Hot Water Cost-Efficiency Curve

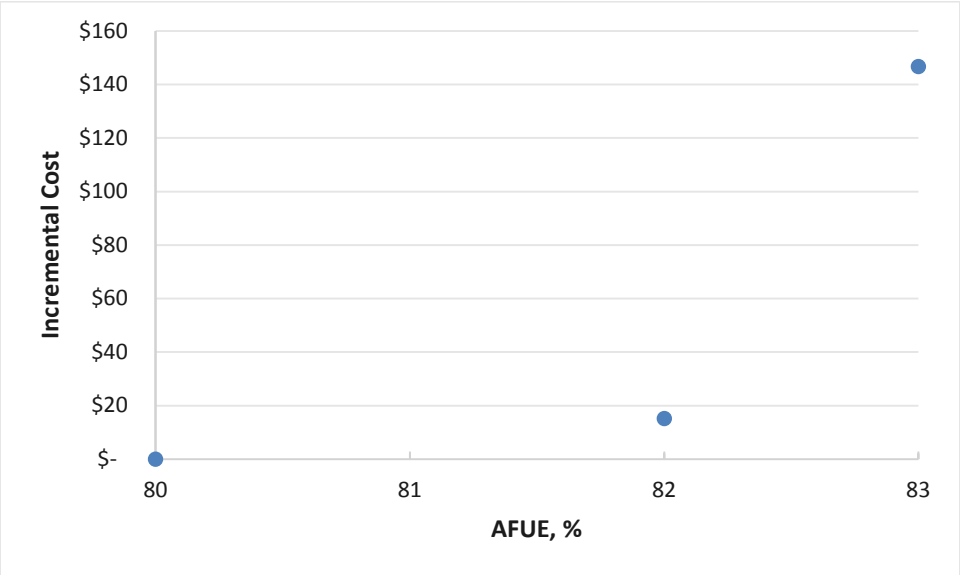

Figure 5.7.2 AFUE Gas Steam Cost-Efficiency Curve

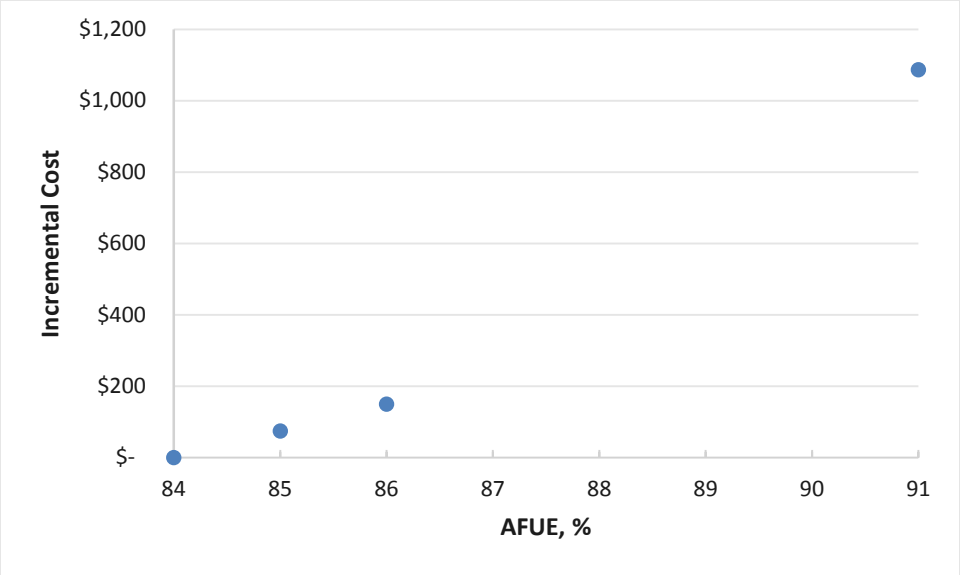

Figure 5.7.3 AFUE Oil Hot Water Cost-Efficiency Curve

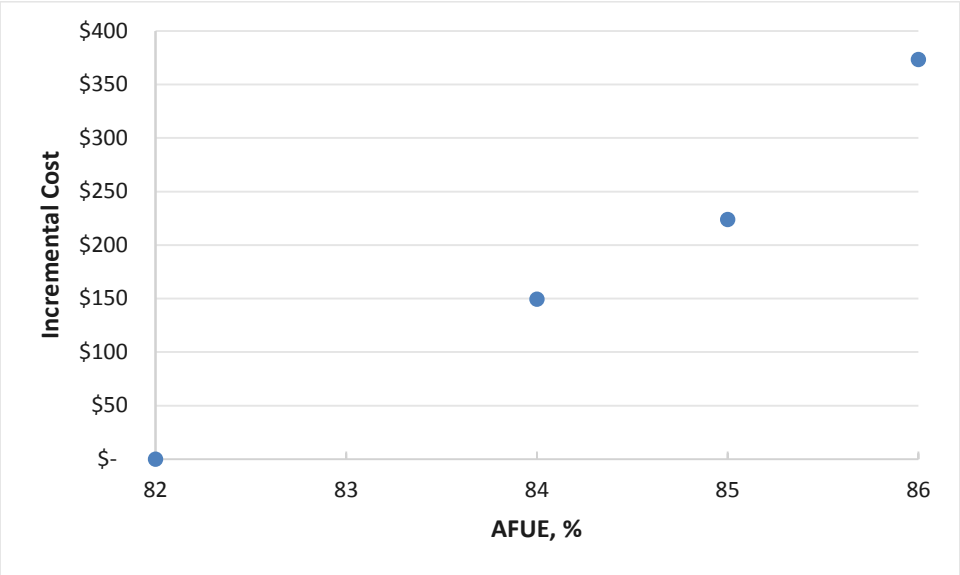

Figure 5.7.4 AFUE Oil Steam Cost-Efficiency Curve

The results of the standby and off mode engineering analysis are reported as cost-power consumption data in the form of power (in watts) versus MPC (in dollars). For each design option that passed the screening analysis (chapter 4), DOE estimated the power consumption reduction of the design option based on the DOE test procedure. DOE developed several sets of standby and off mode data: two for gas, two for oil, and two for electric boilers. DOE observed that boilers generally do not have a seasonal off switch and therefore assumed that the standby mode and off mode power consumption are equal. Discussions with manufactures indicated that though some boilers may be equipped with a service switch it, is not typically used as a seasonal off switch.

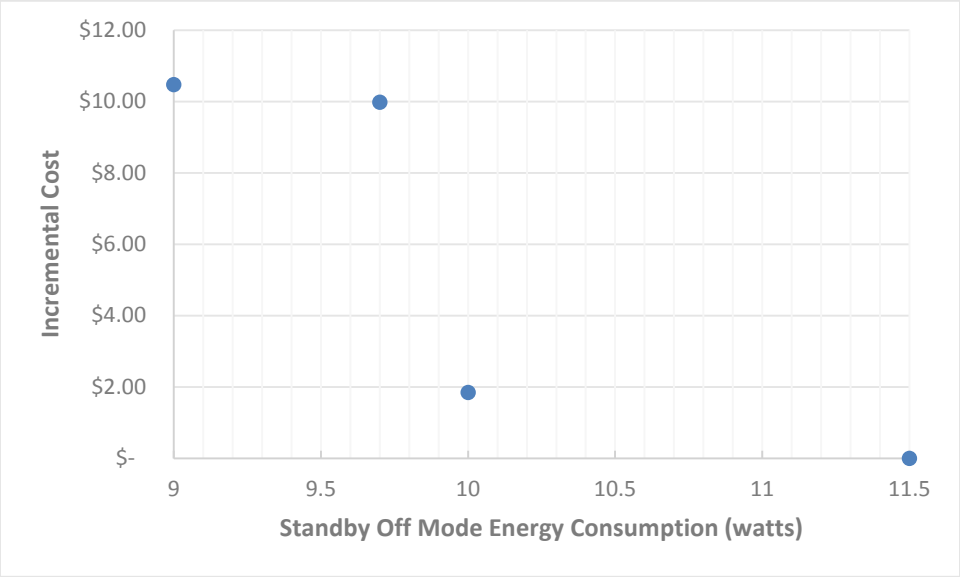

Figure 5.7.5 Gas Hot Water Standby and Off Mode Cost-Efficiency Curve

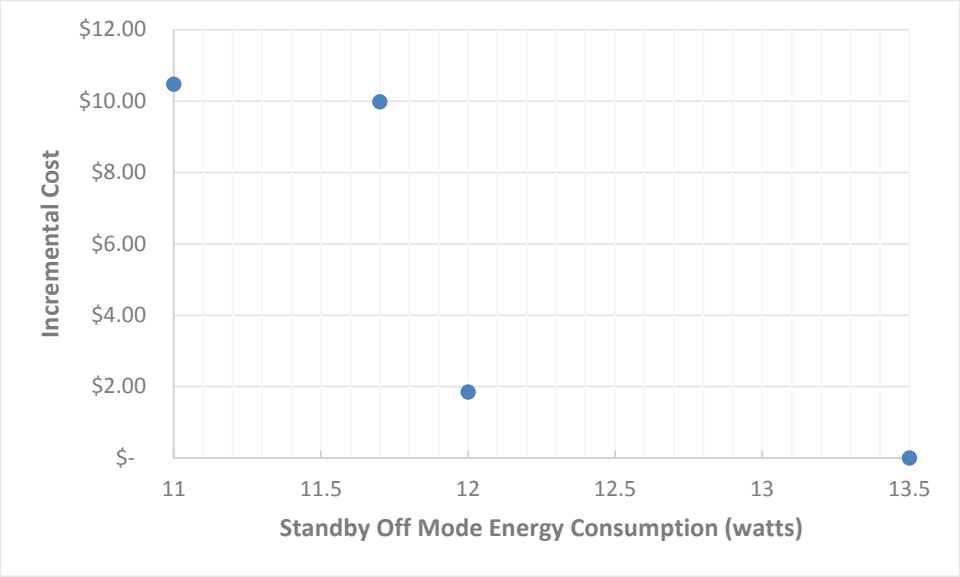

Figure 5.7.6 Oil Hot Water Standby and Off Mode Cost-Efficiency Curve

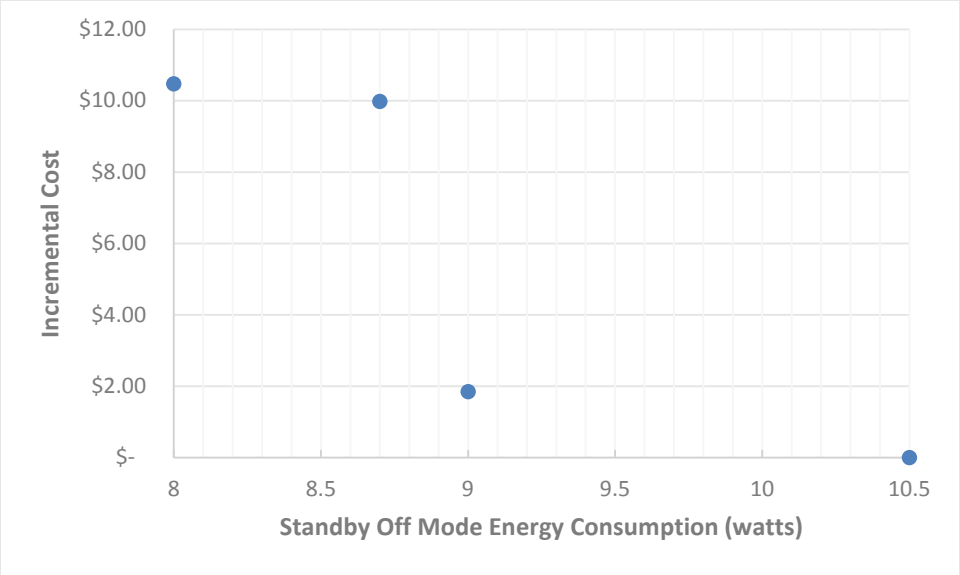

Figure 5.7.7 Gas Steam Standby and Off Mode Cost-Efficiency Curve

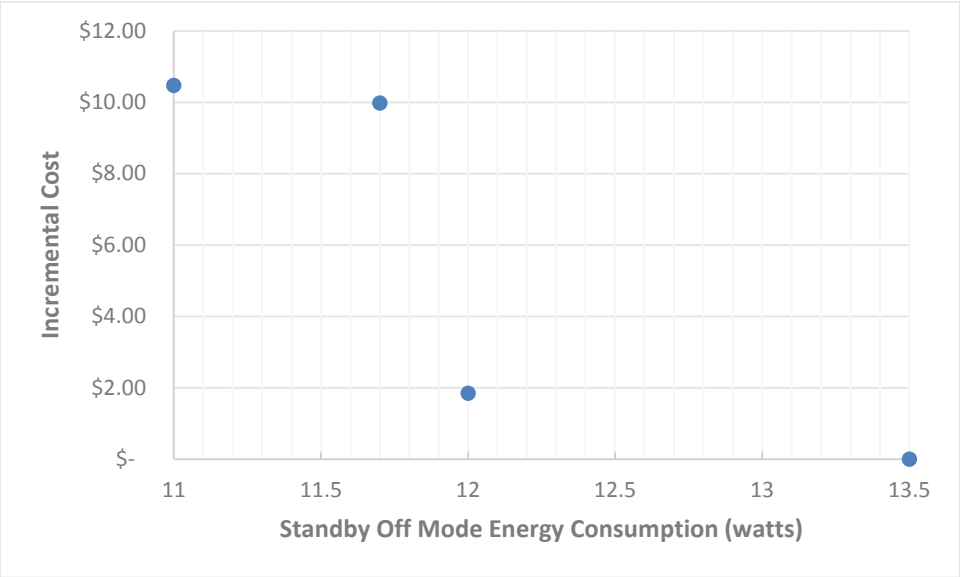

Figure 5.7.8 Oil Steam Standby and Off Mode Cost-Efficiency Curve

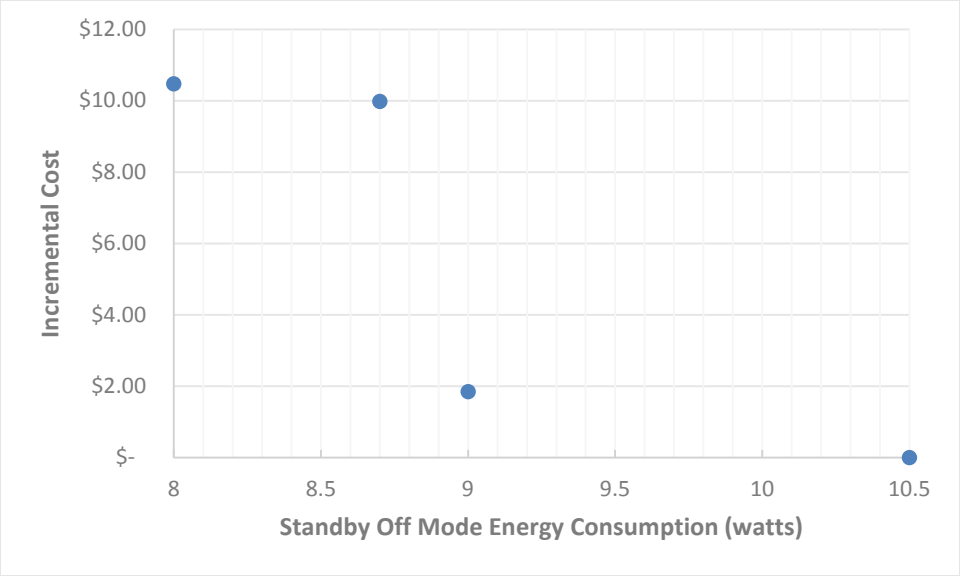

Figure 5.7.9 Electric Hot Water Standby and Off Mode Cost-Efficiency Curve

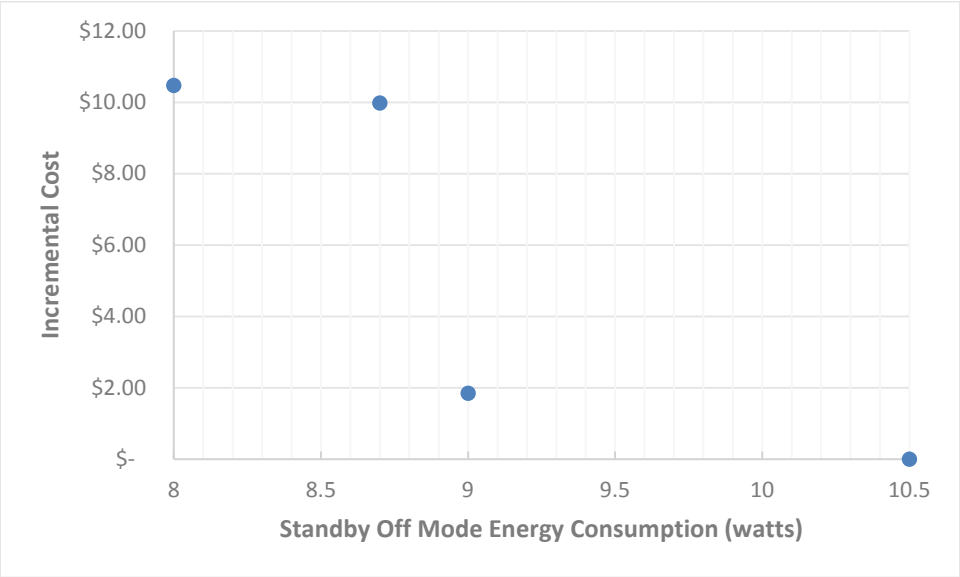

Figure 5.7.10 Electric Steam Standby and Off Mode Cost-Efficiency Curve

5.8 MANUFACTURER MARKUP

A manufacturer markup is applied to the MPC of the product to arrive at the MSP. In general, the manufacturer markup should ensure that the MSP of the product is high enough to recover the full cost of the product (*i.e.*, full production and nonproduction costs), and yield a satisfactory profit. The MSP is the price at which the manufacturer can recover all production and nonproduction costs and earn a profit. DOE calculated the MSP for residential boilers by

multiplying the MPCs by the calculated manufacturer markup, as explained below.

To meet new or amended energy conservation standards, manufacturers typically must introduce design changes to their product lines, which often result in increased MPCs. Depending on the competitive environment for these particular products, some or all of the increased production costs can be "passed through" to retailers and eventually to customers in the form of higher purchase prices. As production costs increase, manufacturers also typically incur additional overhead at the factory and corporate levels. The MSP must cover both of these contributions to overhead if a company is to maintain profitability. As discussed previously, overhead costs in the DOE model are a function of investments, material costs, labor costs, or total costs, depending on the overhead category. Together, materials, labor, and factory overhead make up the full production cost. DOE applies another multiplier to the full production cost to account for corporate nonproduction costs and profit. This multiplier, the nonproduction cost markup, or manufacturer markup, is the focus of this section.

In this section, DOE presents its methodology for converting the MPCs to MSPs, which is done using the nonproduction cost markup. The manufacturer markup is an integral part of the overall markup, which also includes the markups in the distribution chain (*e.g.*, wholesalers, distributors, retailers, contractors). The distribution chain markups convert MSP to retail price. The retail prices and installation costs are key inputs to the LCC analysis, PBP analysis, and the NIA. Using manufacturer and distribution chain markups and installation costs, DOE can calculate the first costs that customers would face under each efficiency level. DOE evaluates the tradeoff between the increase in first cost and the resulting operational cost savings at each efficiency level in the LCC and PBP analyses (chapter 8), and NIA (chapter 10).

The manufacturer markup also has an important bearing on profitability. A high markup under a standards scenario suggests manufacturers can pass through the increased variable costs and some of the capital and product conversion costs (onetime expenditures). A low markup implies that manufacturers will not be able to recover as much of the necessary investment in plant and equipment.

5.8.1 Manufacturer Markup Calculation

Publicly owned companies are required by law to disclose financial information on a regular basis by filing different forms with the U.S. Securities and Exchange Commission (SEC). The SEC form 10-K, filed by companies on an annual basis, provides a comprehensive overview of the company's business and financial conditions. Relevant information in the 10-K reports includes the company's revenues and direct and indirect costs. For the manufacturer markups, DOE used 10-K reports from publicly owned residential boiler companies. The financial figures necessary for calculating the manufacturer markup are net sales, costs of sales, and gross profit. The income statement section of the 10-K reports often lists these figures.

DOE calculated an initial estimate of the baseline manufacturer markups by using financial figures from manufacturers' SEC 10-K reports, such as the net sales (revenues) and cost of sales to calculate gross profit and gross profit margins. DOE used averages of the financial figures spanning 2008 to 2012 and then calculated the markups.

DOE used the following equations to calculate the gross profit and gross profit margins:

$$\text{Gross Profit} = \text{Net Sales} - \text{Cost of Sales} \qquad \text{Eq. 1}$$

$$\text{Gross Profit Margin} = \frac{\text{Gross Profit}}{\text{Net Sales}} \qquad \text{Eq. 2}$$

To calculate the time average gross profit margin for each firm, DOE first summed the gross profit for all the years and then divided the result by the sum of the net sales for the same years. Each manufacturer's nonproduction cost markup was calculated as:

$$\text{Non-production cost markup} = \frac{1}{(1 - \text{Gross Profit Margin})} = \frac{\text{Gross Profit}}{\text{Cost of Sales}} \qquad \text{Eq. 3}$$

After calculating the average markup for each individual manufacturer, DOE averaged them together based on their approximate market shares as estimated by DOE to create an industry-average markup.

DOE calculated the average manufacturer market to be 1.41. In other words, residential boiler manufacturers, on average, sell their products to the next party in the distribution channel at 41 percent above the full manufacturing production cost.

DOE acknowledges that many manufacturers of residential boilers are privately held companies, companies owned through employee stock ownership plans, and companies owned through private stock plans. Consequently, these companies do not file SEC 10-K reports. In addition, while the publicly owned companies file SEC 10-K reports, the financial information summarized is not exclusive for the residential boiler portion of their business. It can include financial information from other product sectors, whose margins could be quite different from the residential boiler industries.

DOE considered the feedback from residential boiler manufacturers in order to supplement the information presented above, and after discussions with manufacturers, DOE determined the estimated manufacturer markup of 1.41 for the residential boiler industry is on an aggregate basis is appropriate. When considering manufacturer feedback related to the markup, DOE aggregated the feedback received from manufacturers on a market-share-weighted basis.

As noted previously, the manufacturer markup is a multiplier used in the engineering analysis to determine the MSPs for each of the representative product classes. DOE used a constant markup to reflect the MSPs of the baseline products as well as more efficient products. DOE took this approach because new or amended standards may make high-efficiency products, which currently are considered premium products, the baseline product and thus it would become a commodity.

5.9 ENGINEERING ANALYSIS SUMMARY OF RESULTS

The results from the engineering analysis are used in the LCC analysis to determine consumer prices for residential boilers at the efficiency levels analyzed. Using the calculated manufacturer markup, DOE calculated the MSPs of the residential boilers at the baseline and more efficient levels.

5.9.1 Summary of Results for Representative Models

Each of the MPCs and MSPs developed in the engineering analysis for the representative capacity are shown in Table 5.9.1 through Table 5.9.4. DOE was able to receive manufacturer feedback on these MPCs and MSPs during the manufacturer interviews. As described in section 5.8, the MSP for residential boilers is calculated by multiplying the MPC by the manufacturer markup. DOE has included transportation costs in its calculation of manufacturer selling price. This manufacture markup is based on an analysis of manufacturer SEC 10-K reports, which include outbound freight costs. Outbound freight is normally considered a sales expense and not a production cost. Inbound freight costs are included in the MPCs as a component of the cost for purchased parts and raw materials.

Table 5.9.1 MPC and MSP for Gas-Fired Hot Water Boilers (100,000 Btu/h input)

Efficiency Level	MPC 2014$	MSP 2014$
Baseline (AFUE=82%)	626.90	883.93
1 (AFUE=83%)	634.51	894.66
2 (AFUE=84%)	642.12	905.39
3 (AFUE=85%)	677.20	954.86
4 (AFUE=90%)	1,009.61	1,423.55
5 (AFUE=92%)	1,180.21	1,664.10
6 (AFUE=96%)	1,516.10	2,137.70

Table 5.9.2 MPC and MSP for Gas-Fired Steam Boilers (100,000 Btu/h input)

Efficiency Level	MPC 2014$	MSP 2014$
Baseline (AFUE=80%)	778.16	1,097.21
1 (AFUE=82%)	793.38	1,118.67
2 (AFUE=83%)	924.80	1,303.97

Table 5.9.3 MPC and MSP for Oil-Fired Hot Water Boilers (140,000 Btu/h input)

Efficiency Level	MPC 2014$	MSP 2014$
Baseline (AFUE=84%)	1,227.79	1,731.18
1 (AFUE=85%)	1,302.45	1,836.45
2 (AFUE=86%)	1,377.11	1,941.72
3 (AFUE=91%)	2,314.33	3,263.20

Table 5.9.4 MPC and MSP for Oil-Fired Steam Boilers (140,000 Btu/h input)

Efficiency Level	MPC 2014$	MSP 2014$
Baseline (AFUE=82%)	1,251.50	1,731.18
1 (AFUE=84%)	1,400.82	1,975.16
2 (AFUE=85%)	1,475.48	2,080.43
3 (AFUE=86%)	1,624.80	2,290.97

Table 5.9.5 MPC and MSP for Gas-Fired Hot Water Boilers Standby

Efficiency Level	MPC 2014$	MSP 2014$
Baseline	8.55	12.06
1	10.40	14.66
2	18.53	26.13
3	19.02	26.82

Table 5.9.6 MPC and MSP for Gas-Fired Steam Boilers Standby

Efficiency Level	MPC 2014$	MSP 2014$
Baseline	8.55	12.06
1	10.40	14.66
2	18.53	26.13
3	19.02	26.82

Table 5.9.7 MPC and MSP for Oil-Fired Hot Water Boilers Standby

Efficiency Level	MPC 2014$	MSP 2014$
Baseline	8.55	12.06
1	10.40	14.66
2	18.53	26.13
3	19.02	26.82

Table 5.9.8 MPC and MSP for Oil-Fired Steam Boilers Standby

Efficiency Level	MPC 2014$	MSP 2014$
Baseline	8.55	12.06
1	10.40	14.66
2	18.53	26.13
3	19.02	26.82

Table 5.9.9 MPC and MSP for Electric Hot Water Boilers Standby

Efficiency Level	MPC 2014$	MSP 2014$
Baseline	8.55	12.06
1	10.40	14.66
2	18.53	26.13
3	19.02	26.82

Table 5.9.10 MPC and MSP for Electric Steam Boilers Standby

Efficiency Level	MPC 2014$	MSP 2014$
Baseline	8.55	12.06
1	10.40	14.66
2	18.53	26.13
3	19.02	26.82

CHAPTER 6. MARKUPS ANALYSIS

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CHAPTER 6. MARKUP ANALYSIS

6.1 INTRODUCTION

To carry out its analyses, the U.S. Department of Energy (DOE) needed to determine the cost to the consumer of baseline efficiency products and the cost of more efficient units the consumer would purchase under new energy conservation standards. DOE calculated such costs based on engineering estimates of manufacturing costs plus appropriate markups for the various distribution channels for residential boilers.

For wholesalers and contractors, DOE estimated a baseline markup and an incremental markup. DOE defines a baseline markup as a multiplier that converts the manufacturer selling price (MSP) of equipment with baseline efficiency to the consumer purchase price for the equipment at the same baseline efficiency level. An incremental markup is defined as the multiplier to convert the incremental increase in manufacturer selling price of higher efficiency equipment to the consumer purchase price for the same equipment. Because companies mark up the price at each point in the distribution channel, both overall baseline and incremental markups are dependent on the distribution channel, as described in section 6.2.

Generally, companies mark up the price of a product to cover their business costs and profit margin. In financial statements, gross margin is the difference between the company revenue and the company cost of sales or cost of goods sold (*CGS*). The gross margin takes account of the expenses of companies in the distribution channel, including overhead costs (sales, general, and administration); research and development (R&D); interest expenses; depreciation; and taxes—and company profits. In order for sales of a product to contribute positively to company cash flow, the product's markup must be greater than the corporate gross margin. Products command lower or higher markups, depending on company expenses associated with the product and the degree of market competition.

6.2 DISTRIBUTION CHANNELS

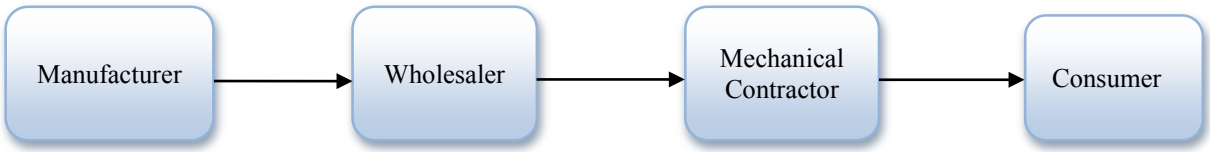
The appropriate markups for determining consumer equipment prices depend on the type of distribution channels through which products move from manufacturers to purchasers. In the case of residential boilers, the majority of units are purchased for residential use, but a small fraction of residential boilers are purchased to be installed in small to mid-size commercial buildings. DOE estimated that 92 percent of gas-fired hot water and steam boiler shipments, 95 percent of oil-fired hot water and steam boiler shipments, and 68 percent of electric hot water and steam boiler shipments are to residential applications, the remainder of the shipments being to commercial applications. Hence, DOE calculated the markups separately for residential and commercial applications of residential boilers.

Within each application, there are two primary types of markets describing the way most products pass from the manufacturer to the consumer, one applying to residential boilers installed in pre-existing buildings (either replacement of failed units or new installation of boilers in buildings previously without one) and the other applying to residential boilers that are

installed in new construction. In the replacement distribution channel, the manufacturer generally sells the equipment to a wholesaler, who in turn sells it to a mechanical contractor, who in turn sells it to the consumer. The new construction distribution channel includes an additional link in the chain—the general contractor. In the new construction distribution channel, the manufacturer sells the equipment to a wholesaler, who in turn sells it to a mechanical contractor, who in turn sells it to a general contractor then to the consumer.

Figure 6.2.1 illustrates the two main distribution channels for residential boilers in residential applications.

Replacement and New Owner:



New Construction:

Figure 6.2.1 Distribution Channels for Residential Boilers in Residential Applications

For residential boilers in commercial applications, DOE considers an additional distribution channel for which the manufacturer sells the equipment to the wholesaler and then to the consumer through a national account under both replacement and new construction markets. This national account distribution channel is applicable to small to mid-size commercial buildings where the on-site staff or internal personnel generally purchase equipment from wholesalers at much lower prices due to the large volume purchased and perform the installation themselves. Occasionally, the equipment manufacturers and wholesalers can be the same entity, so the consumer selling price could potentially be even lower than the usual national account channel. However, DOE did not have sufficient information to determine the appropriate markup for this particular distribution channel.

Figure 6.2.2 shows the main distribution channels for residential boilers in commercial applications.

Replacement:

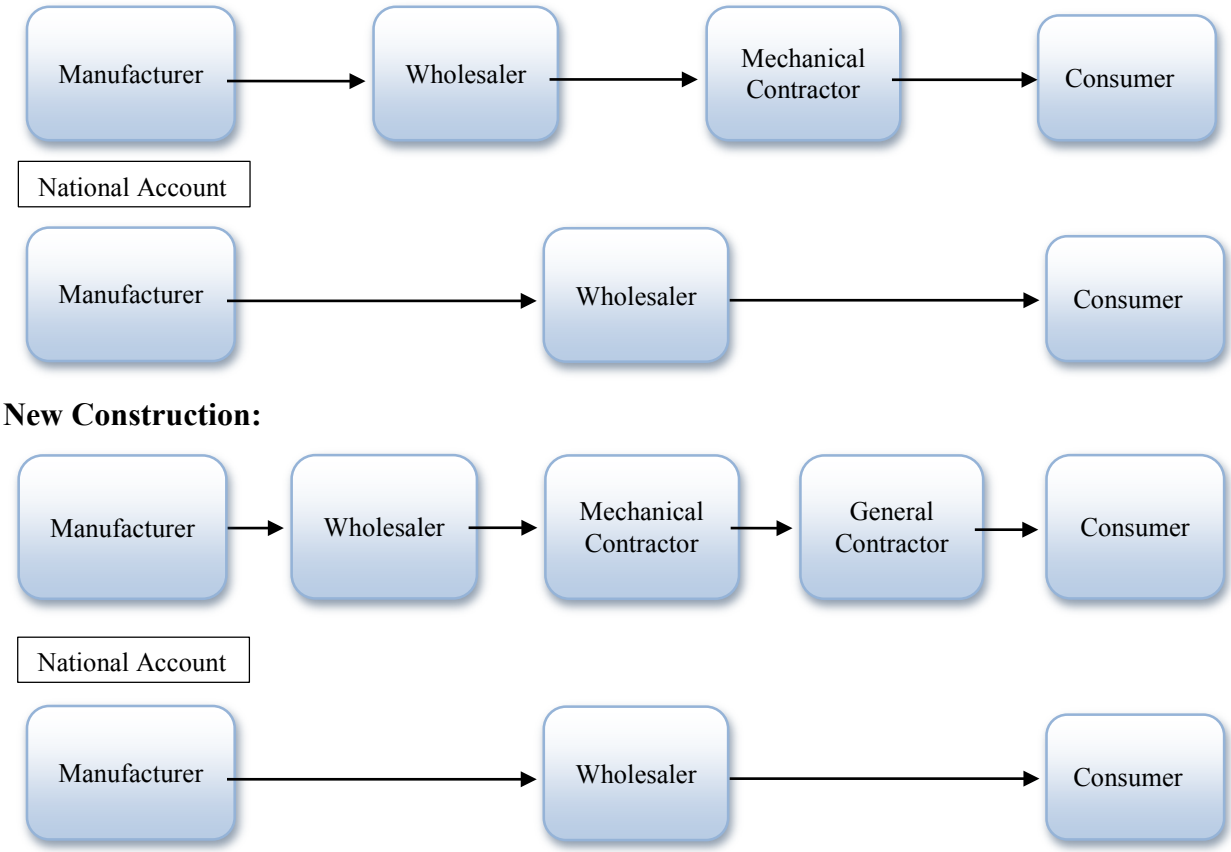


Figure 6.2.2 Distribution Channels for Residential Boilers in Commercial Applications

Based on information provided from manufacturer interviews, there is another possible distribution channel which includes retail store instead of wholesaler. In this case, the manufacturer sells the equipment to a retailer, who in turn sells it to a mechanical contractor, who in turn sells it to the consumer. However, DOE does not have enough information at this point to compute a separate markup estimate for this distribution channel. DOE would assume that the retailer markup is similar to the wholesaler markup. DOE is also aware that there may be two additional distribution channels for residential boilers: (1) online distribution where manufacturers sell the products to online retailers who in turn sell them directly to consumers, and (2) rebranding distribution channel where wholesalers or retailers negotiate good pricing from the boiler manufacturer based on high volumes and have the product customized to carry their name, and then send it through their normal distribution channel to the contractors. The former channel mainly applies to do-it-yourself (DIY) installation representing around two percent of the total HVAC shipments, which implies an even smaller fraction of the total residential boiler shipments. For the latter channel, DOE assumes that it would have the same overall markups as the conventional distribution channels. Although manufacturers may have lower margin, wholesalers and retailers would redistribute the profit throughout the distribution

channel to have the final retail price comparable with products sold through conventional distribution channels. Due to the small market representation of these two additional distribution channels, DOE did not consider them separately in this analysis.

6.3 MANUFACTURER MARKUP

DOE uses manufacturer markups to transform a manufacturer's product cost into a manufacturer selling price. A detailed description of the methodology used to derive manufacturer markups were described in chapter 5, Engineering Analysis. Table 6.3.1presents manufacturer markups for the six different product classes considered in this analysis.

Table 6.3.1 Manufacturer Markups by Residential Boiler Product Class

Product Class	Baseline Markup
Gas-Fired Hot Water Boiler	1.41
Gas-Fired Steam Boiler	1.41
Oil-Fired Hot Water Boiler	1.41
Oil-Fired Steam Boiler	1.41
Electric Hot Water Boiler	1.41
Electric Steam Boiler	1.41

6.4 WHOLESALER AND CONTRACTOR MARKUPS

A change in energy efficiency standards usually increases the manufacturer selling price that wholesalers pay, and in turn the wholesale price that contractors pay. In the past, DOE used the same markups as for baseline products to estimate the product price of more efficient product. Applying a fixed markup on higher manufacturer selling price would imply an increase in the dollar margin earned by wholesalers and contractors, and an increase in per-unit profit.

Based on microeconomic theory, the degree to which firms can pass along a cost increase depends on the level of market competition, as well as the market structure on both supply and demand side (e.g., supply and demand elasticity). DOE examined industry data from IBISWorld and the results suggest that most of the industries relevant to heating and air-conditioning wholesalers and contractors are generally quite competitive (see appendix 6B).[a] In addition, consumer demand for heating and air conditioning is relatively inelastic (*i.e.*, demand is not expected to decrease substantially with an increase in the price of equipment). Under relatively competitive markets, it may be tenable for HVAC wholesalers and contractors to maintain a fixed markup for a short period of time after the input price increases, but the market competition should eventually force them to readjust their markups to reach a medium-term equilibrium of which per-unit profit is relatively unchanged before and after standards are implemented.

[a] IBISWorld, US Industry Reports (NAICS): 23611a - Home Builders, 23622a - Commercial Building Construction, 23822a - Heating & Air-Conditioning Contractors, Heating & Air Conditioning Wholesaling in the US. 2015. (Last accessed August, 2015.) http://clients.ibisworld.com/reports/us/industry/home.aspx

Thus, DOE concluded that applying fixed markups for both baseline products and higher-priced products meeting a standard is not viable in the medium to long term considering the competitive nature of the HVAC wholesale and contractor industry. DOE developed the incremental markup approach based on the widely accepted economic view that firms are not able to sustain a persistently higher dollar margin in a competitive market in the medium term. If the price of the product increases under standards, the only way to maintain the same dollar margin as before is for the markup (and percent gross margin) to decline.

To estimate the markup under standards, DOE derived an incremental markup that is applied to the incremental equipment costs of higher efficiency products. The overall markup on the products meeting standards is an average of the markup on the component of the cost that is equal to the baseline product and the markup on the incremental cost, weighted by the share of each in the total cost of the standards-compliant product.

DOE's incremental markup approach allows the part of the cost that is thought to be affected by the standard to scale with the change in manufacturer price. The income statements DOE used to develop wholesaler and contractor markups itemize firm costs into a number of expense categories, including direct costs to purchase or install the equipment, operating labor and occupancy costs, and other operating costs and profit. Although HVAC wholesalers and contractors tend to handle multiple commodity lines, including room air conditioners, furnaces, central air conditioners and heat pumps, and boilers, DOE contends that these aggregated data provide the most accurate available indication of the expenses associated with residential boilers and the cost structure of distribution channel participants.

DOE uses these income statements to divide firm costs between those that are not likely to scale with the manufacturer price of equipment (labor and occupancy expenses, or "invariant" costs) and those that are (operating expenses and profit, or "variant" costs). For example, when the manufacturer selling price of equipment increases, only a fraction of a wholesaler's expenses increase (operating expenses and profit), while the remainder can be expected to stay relatively constant (labor and occupancy expenses). If the unit price of a residential boiler increases by 20 percent under standards, it is unlikely that the cost of secretarial support in an administrative office or office rental expenses will increase proportionally.

See Appendix 6B for further evidence supporting the use of incremental markups in this analysis. The derivation of incremental markups for wholesalers and contractors is described in the following sections.

6.4.1 Wholesaler Markup Method

DOE developed baseline and incremental markups for wholesalers using the firm income statement from the Heating, Air-Conditioning and Refrigeration Distributors International (HARDI) 2013 Profit Report (Appendix 6A).[1] The baseline markups cover all of the wholesaler's costs (both *invariant costs* and *variant costs*). Here, variant costs were defined as costs that likely vary in proportion to the change in MSP induced by increased efficiency

standards; in contrast, invariant costs were defined as costs that are unlikely to vary in proportion to the change in MSP due to increased efficiency standards. DOE calculated the baseline markup for wholesalers using the following equation:

$$MU_{BASE} = \frac{CGS_{WHOLE} + GM_{WHOLE}}{CGS_{WHOLE}} = \frac{CGS_{WHOLE} + (IVC_{WHOLE} + VC_{WHOLE})}{CGS_{WHOLE}}$$

Eq. 6.1

Where:

MU_{BASE} = baseline wholesaler markup,
CGS_{WHOLE} = wholesaler cost of goods sold,
GM_{WHOLE} = wholesaler gross margin,
IVC_{WHOLE} = wholesaler invariant costs, and
VC_{WHOLE} = wholesaler variant costs.

Incremental markups are multipliers that relate the change in the MSP of products that meet the requirements of new efficiency standards to the change in the wholesaler sales price. Incremental markups cover only those costs that scale with a change in the MSP (*i.e.*, variant costs, *VC*). DOE calculated the incremental markup (MU_{INCR}) for wholesalers using the following equation:

$$MU_{INCR} = \frac{CGS_{WHOLE} + VC_{WHOLE}}{CGS_{WHOLE}}$$

Eq. 6.2

Where:

MU_{INCR} = incremental wholesaler markup,
CGS_{WHOLE} = wholesaler cost of goods sold, and
VC_{WHOLE}= wholesaler variant costs.

6.4.2 Derivation of Wholesaler Markups

Wholesalers reported median data in a confidential survey that HARDI conducted of member firms. In the survey, HARDI itemized revenues and costs into cost categories, including direct equipment expenses (cost of goods sold), labor expenses, occupancy expenses, other operating expenses, and profit. DOE presents these data in full in appendix 6A. Table 6.4.1 summarizes them at the national aggregated level as cost-per-dollar sales revenue in the first data column. These wholesaler markups are applicable to residential boilers in both residential and commercial applications.

Table 6.4.1 Wholesaler Expenses and Markups

Descriptions	Per Dollar Sales Revenue $	Per Dollar Cost of Goods $
Direct Cost of Equipment Sales: Cost of goods sold	0.739	1.000
Labor Expenses: Salaries and benefits	0.151	0.204
Occupancy Expense: Rent, maintenance, and utilities	0.035	0.047
Other Operating Expenses: Depreciation, advertising, and insurance.	0.052	0.070
Operating Profit	0.023	0.031
Wholesaler Baseline Markup ($MU_{WHOLE\ BASE}$)		**1.35**
Incremental Markup ($MU_{WHOLE\ INCR}$)		**1.10**

Source: Heating, Air Conditioning & Refrigeration Distributors International. 2013. 2013 Profit Report (2012 Data).

In this case, direct equipment expenses (cost of goods sold) represent about $0.74 per dollar sales revenue, so for every $1 wholesalers take in as sales revenue, $0.74 is used to pay the direct equipment costs. Labor expenses represent $0.15 per dollar sales revenue, occupancy expenses represent $0.04, other operating expenses represent $0.05, and profit accounts for $0.02 per dollar sales revenue.

DOE converted the expenses per dollar sales into expenses per dollar cost of goods sold, by dividing each figure in the first data column by $0.74 (*i.e.,* cost of goods sold per dollar of sales revenue). The data in column two show that, for every $1.00 the wholesaler spends on equipment costs, the wholesaler allocates $0.20 to cover labor costs, $0.047 to cover occupancy expenses, $0.07 for other operating expenses, and $0.03 in profits. This totals to $1.36 in sales revenue earned for every $1.00 spent on equipment costs. Therefore, the wholesaler baseline markup ($MU_{WHOLE\ BASE}$) is approximately 1.35 ($1.35 ÷ $1.00).

DOE also used the data in column two to estimate the incremental markup. The incremental markup depends on which of the costs in Table 6.4.1 are variant and which are invariant with MSP. For example, for a $1.00 increase in the MSP, if all of the other costs scale with the MSP (*i.e.,* all costs are variant), the increase in wholesale price will be $1.352, implying that the incremental markup is 1.35, or the same as the baseline markup. At the other extreme, if none of the other costs are variant, then a $1.00 increase in the MSP will lead to a $1.00 increase

in the wholesale price, for an incremental markup of 1.0. DOE believes that the labor and occupancy costs will be invariant and that the other operating costs and profit will scale with the MSP (*i.e.,* be variant). In this case, for a $1.00 increase in the MSP, the wholesale price will increase by $0.10 to match changes in "other" operating costs and operating profit, giving a wholesaler incremental markup ($MU_{WHOLE\ INCR}$) of 1.10. See appendix 6A for cost details

6.4.3 Mechanical and General Contractor Markups Method

As both mechanical and general construction industries are relatively competitive, DOE used similar approach to that described in section 6.4.1 to develop contractor markups. The type of itemized financial data used to estimate wholesaler markups are also available for mechanical contractors and general contractors from 2012 Economic Census. DOE collected financial data from the Plumbing and HVAC Contractors (NAICS 23822) series,[2] Residential Building Construction series (NAICS 236110),[3] and Commercial Building Construction series (NAICS 236220)[4] to estimate national average markups for mechanical contractors, residential general contractors, and commercial general contractors, respectively.

DOE calculated the national average baseline markup for mechanical and general contractors using the following equation:

$$MU_{BASE} = \frac{CGS_{CONT} + GM_{CONT}}{CGS_{CONT}} = \frac{CGS_{CONT} + (IVC_{CONT} + VC_{CONT})}{CGS_{CONT}}$$

Eq. 6.3

Where:

MU_{BASE}= baseline mechanical/general contractor markup,
CGS_{CONT}= mechanical/general contractor cost of goods sold,
GM_{CONT}= mechanical/general contractor gross margin,
IVC_{CONT}= mechanical/general contractor invariant cost, and
VC_{CONT} = mechanical/general contractor variant costs.

Analogously to wholesalers, DOE estimated the incremental mechanical contractor and general contractor markups by only marking up those costs that scale with a change in the MSP (variant costs, *VC*) for more energy-efficient products. As above, DOE assumed a division of costs between those that do not scale with the manufacturer price (labor and occupancy expenses), and those that do (other operating expenses and profit). Hence, DOE categorized the Census data into each major cost category and estimated incremental markups using the following equation:

$$MU_{INCR} = \frac{CGS_{CONT} + VC_{CONT}}{CGS_{CONT}}$$

Eq. 6.4

Where:

MU_{INCR} = incremental mechanical/general contractor markup,
CGS_{CONT} = mechanical/general contractor cost of goods sold, and
VC_{CONT} = mechanical/general contractor variant costs.

To differentiate mechanical contractor markups between replacement and new construction market, DOE relied on ACCA 2005 Financial Analysis as it provides gross margin as percent of sales for replacement and new construction market separately.[5] Therefore, the baseline markup for both markets can be derived with the following equation:

$$MU_{BASE} = \frac{Sales(\%)}{Sales(\%) - GM(\%)}$$

Eq. 6.5

DOE then calculated the markup ratios of replacement and new construction market to all mechanical contractors derived from ACCA 2005 Financial Analysis and applied those ratios to the national average markup results from 2012 Economic Census to develop the baseline and incremental markups for replacement and new construction markets.

6.4.4 Derivation of Mechanical Contractor Markups

6.4.4.1 Aggregate Markups for Mechanical Contractors

The 2012 Economic Census provides Geographic Area Series for the *Plumbing and HVAC Contractors* (NAICS 23822) sector, which contains national average sales and cost data, including value of construction, cost of subcontract work, cost of materials, and payroll for construction workers. It also provides the cost breakdown of gross margin, including labor expenses, occupancy expenses, other operating expenses, and profit. The gross margin provided by the U.S. Census is disaggregated enough that DOE was able to determine the invariant (labor and occupancy expenses) and variant (other operating expenses and profits) costs for this particular sector. By using the equation mentioned above, baseline and incremental markups were estimated. The markup results representing the plumbing and HVAC contractor industry at the national aggregated level are presented in Table 6.4.2. (Appendix 6A contains the full set of data.)

Table 6.4.2 Mechanical Contractor Expenses and Markups Based on Census Bureau Data

Description	Mechanical Contractor Expenses or Revenue	
	Per Dollar Sales Revenue $	**Per Dollar Cost of Goods $**
Direct Cost of Equipment Sales: Cost of goods sold	0.664	1.00
Labor Expenses: Salaries (indirect) and benefits	0.175	0.26
Occupancy Expense: Rent, maintenance, and utilities	0.026	0.04
Other Operating Expenses: Depreciation, advertising, and insurance.	0.092	0.14
Net Profit Before Taxes	0.043	0.07
Baseline Markup (*MUMECH BASE*): Revenue per dollar cost of goods		**1.51**
Incremental Markup (*MUMECH INCR*): Increased revenue per dollar increase in cost of goods sold		**1.20**

Source: U.S. Census Bureau. 2012. Plumbing, Heating, and Air-Conditioning Contractors. Sector 23: 238220. Construction: Industry Series, Preliminary Detailed Statistics for Establishments, 2012.

The first data column in Table 6.4.2 provides the cost of goods sold and a list of gross margin components as expenses per dollar of sales revenue. As shown in the table, the direct cost of sales represents about $0.66 per dollar sales revenue to the mechanical contractor, and the gross margin totals $0.34 per dollar sales revenue. DOE converted these expenses per dollar sales into revenue per dollar cost of goods sold by dividing each figure in the first data column by $0.66. For every $1.00 the mechanical contractor spends on equipment costs, the mechanical contractor earns $1.00 in sales revenue to cover the equipment cost and $0.51 to cover the other costs. This totals $1.51 in sales revenue earned for every $1.00 spent on equipment costs. This is equivalent to a baseline markup ($MU_{MECH\ CONT\ BASE}$) of 1.51 for mechanical contractors.

DOE used the data in column two in Table 6.4.2 to estimate the incremental markups, after classifying the costs as either invariant or variant. At one extreme, if all of the other costs scale with the equipment price (*i.e.,* all costs are variant), the increase in general contractor price will be $1.51, implying that the incremental markup is 1.51 or the same as the baseline markup. At the other extreme, if none of the other costs are variant, then a $1.00 increase in the equipment price will lead to a $1.00 increase in the general contractor price, for an incremental markup of 1.0. DOE believes the labor and occupancy costs are invariant and the other operating costs and profit scale with the equipment price (*i.e.,* are variant). In this case, for a $1.00 increase in the equipment price, the general contractor price will increase by $1.20, giving a general contractor incremental markup ($MU_{MECH\ CONT\ INCR}$) of 1.20.

6.4.4.2 Markups for Mechanical Contractors in the Replacement and New Construction Markets

DOE derived the baseline and incremental markups for both replacement and new construction markets using the 2012 Economic Census industrial cost data supplemented with

the most recent ACCA 2005 financial data. The 2007 Economic Census provides sufficient detailed cost breakdown for the *Plumbing and HVAC Contractors* (NAICS 23822) sector so that DOE was able to estimate baseline and incremental markups for mechanical contractors. However, the 2012 Economic Census does not separate the mechanical contractor market into replacement and new construction markets. To calculate markups for these two markets, DOE utilized 2005 ACCA financial data, which reports gross margin data for the entire mechanical contractor market and for both the replacement and new construction markets.

The HVAC contractors, defined here as mechanical contractors, reported median cost data in an ACCA 2005 financial analysis of the HVAC industry. These data are shown in Table 6.4.3.

Table 6.4.3 Baseline Markup, All Mechanical Contractors

Description	Contractor Expenses or Revenue	
	Per Dollar Sales Revenue ***$***	**Per Dollar Cost of Goods** ***$***
Direct Cost of Equipment Sales: Cost of goods sold	0.7286	1.000
Gross Margin: Labor, occupancy, operating expenses, and profit	0.2714	0.372
Revenue: Baseline revenue earned per dollar cost of goods		**1.372**
Baseline Markup (*$MU_{MECH\ CONT\ BASE}$*)		**1.372**

Source: Air Conditioning Contractors of America. 2005. Financial Analysis for the HVACR Contracting Industry.

Table 6.4.4 summarizes the gross margin and resulting baseline markup data for all mechanical contractors that serve the replacement and new construction markets.

Table 6.4.4 Baseline Markups for the Replacement and New Construction Markets, All Mechanical Contractors

Description	Contractor Expenses or Revenue by Market Type			
	Replacement		New Construction	
	Per Dollar Sales Revenue $	Per Dollar Cost of Goods $	Per Dollar Sales Revenue $	Per Dollar Cost of Goods $
Direct Cost of Equipment Sales: Cost of goods sold	0.7031	1.000	0.745	1.000
Gross Margin: Labor, occupancy, operating expenses, and profit	0.2969	0.422	0.255	0.342
Baseline Markup (*MUMECH CONT BASE*): Revenue per dollar cost of goods	NA	**1.422**	NA	**1.342**
% Difference from Aggregate Mechanical Contractor Baseline MU	NA	**3.63%**	NA	**-2.20%**

Source: Air Conditioning Contractors of America. 2005. Financial Analysis for the HVACR Contracting Industry.

Using the average baseline markups estimated for replacement and new construction market from Table 6.4.4 and the average baseline markup for all mechanical contractors from Table 6.4.3, DOE calculated that the baseline markups for the replacement and new construction markets are 3.63 percent higher and 2.20 percent lower, respectively, than for all mechanical contractors serving all markets.

The markup deviations (*i.e.,* 3.63 percent higher and 2.20 percent lower for the replacement and new construction markets, respectively) derived for all mechanical contractors were then applied to the baseline markup of 1.51 and the incremental markup of 1.20 estimated for the *Plumbing and HVAC Contractors* (NAICS 23822) sector in Table 6.4.2. DOE assumed that this deviation applies equally to the baseline and incremental markups calculated from the 2012 Economic Census. The results of the baseline and incremental markups for the replacement and new construction markets served by mechanical contractors are shown in Table 6.4.5.

Table 6.4.5 Markups for the Replacement and New Construction Markets

	Baseline Markup	Incremental Markup
Replacement Market	1.56	1.25
New Construction Market	1.47	1.18

6.4.5 Derivation of General Contractor Markups

DOE derived markups for general contractors from U.S. Census Bureau data for the residential building construction and commercial building construction sectors to reflect the residential and commercial application of residential boilers.[9] The residential construction sector includes establishments primarily engaged in construction work, including new construction work, additions, alterations, and repairs of residential buildings, whereas the commercial construction sector includes establishments primarily responsible for the construction of commercial and institutional buildings.[10] The U.S. Census Bureau data for the construction sector include detailed statistics for establishments with payrolls, similar to the data reported by HARDI for wholesalers. The primary difference is that the U.S. Census Bureau reports itemized revenues and expenses for the construction industry as a whole in total dollars rather than in typical values for an average or representative business. Because of this, DOE assumed that the total dollar values that the U.S. Census Bureau reported, once converted to a percentage basis, represent revenues and expenses for an average or typical contracting business. Similar to the data for wholesalers, Table 6.4.6 summarizes the expenses for general contractors in residential building construction at the national aggregated level as expenses per dollar sales revenue in the first data column. (Appendix 6A contains the full set of data.)

Table 6.4.6 Residential Building General Contractor Expenses and Markups

Description	General Contractor Expenses or Revenue	
	Per Dollar Sales Revenue $	**Per Dollar Cost of Goods $**
Direct Cost of Equipment Sales: Cost of goods sold	0.735	1.000
Labor Expenses: Salaries (indirect) and benefits	0.080	0.109
Occupancy Expense: Rent, maintenance, and utilities	0.015	0.020
Other Operating Expenses: Depreciation, advertising, and insurance.	0.072	0.098
Net Profit Before Taxes	0.099	0.135
Baseline Markup (*MUGEN CONT BASE*): Revenue per dollar cost of goods		**1.36**
Incremental Markup (*MUGEN CONT INCR*): Increased revenue per dollar increase in cost of goods sold		**1.23**

Source: U.S. Census Bureau. 2012. Residential Building Construction. Sector 23: 236115-236118. Construction: Industry Series: Preliminary Detailed Statistics for Establishments: 2012.

As shown in the first column, the direct cost of sales represents about $0.74 per dollar sales revenue to the general contractor. Labor expenses represent $0.08 per dollar sales revenue, occupancy expenses represent $0.02 per dollar sales revenue, other operating expenses represent $0.07, and profit makes up $0.10 per dollar sales revenue.

DOE converted these expenses per dollar sales into revenue per dollar cost of goods sold, by dividing each figure in the first data column by $0.74. The data in column two show that, for

every $1.00 the general contractor spends on equipment costs, the general contractor earns $1.00 in sales revenue to cover the equipment cost, $0.11 to cover labor costs, $0.02 to cover occupancy expenses, $0.10 for other operating expenses, and $0.14 in profits. This totals to $1.36 in sales revenue earned for every $1.00 spent on equipment costs. Thus, the general contractor baseline markup ($MU_{GEN\ CONT\ BASE}$) is 1.36.

DOE used the data in column two in Table 6.4.6 to estimate the incremental markups, after classifying the costs as either invariant or variant. At one extreme, if all of the other costs scale with the equipment price (*i.e.,* all costs are variant), the increase in general contractor price will be $1.36, implying that the incremental markup is 1.36, or the same as the baseline markup. At the other extreme, if none of the other costs are variant, then a $1.00 increase in the equipment price will lead to a $1.00 increase in the general contractor price, for an incremental markup of 1.0. DOE believes the labor and occupancy costs are invariant and the other operating costs and profit scale with the equipment price (*i.e.,* are variant). In this case, for a $1.00 increase in the equipment price, the general contractor price will increase by $1.23, giving a general contractor incremental markup ($MU_{GEN\ CONT\ INCR}$) of 1.23.

Table 6.4.7 summarizes the expenses for general contractors in commercial building construction at the national aggregated level as expenses per dollar sales revenue in the first data column. (Appendix 6A contains the full set of data.)

Table 6.4.7 Commercial Building General Contractor Expenses and Markups

Description	Wholesale Firm Expenses or Revenue	
	Per Dollar Sales Revenue $	**Per Dollar Cost of Goods $**
Direct Cost of Equipment Sales: Cost of goods sold	0.793	1.000
Labor Expenses: Salaries (indirect) and benefits	0.081	0.103
Occupancy Expense: Rent, maintenance, and utilities	0.012	0.016
Other Operating Expenses: Depreciation, advertising, and insurance.	0.046	0.058
Net Profit Before Taxes	0.068	0.085
Baseline Markup (*MUGEN CONT BASE*): Revenue per dollar cost of goods		**1.26**
Incremental Markup (*MUGEN CONT INCR*): Increased revenue per dollar increase cost of goods sold		**1.14**

Source: U.S. Census Bureau. 2012. Sector 236220 (Commercial Building Construction). Construction: Industry Series: Preliminary Detailed Statistics for Establishments: 2012.

As shown in the first column, the direct cost of sales represents about $0.79 per dollar sales revenue to the general contractor. Labor expenses represent $0.08 per dollar sales revenue, occupancy expenses represent $0.01 per dollar sales revenue, other operating expenses represent $0.05, and profit makes up $0.07 per dollar sales revenue.

DOE converted these expenses per dollar sales into revenue per dollar cost of goods sold, by dividing each figure in the first data column by $0.79. The data in column two show that, for every $1.00 the general contractor spends on equipment costs, the general contractor earns $1.00 in sales revenue to cover the equipment cost, $0.10 to cover labor costs, $0.02 to cover occupancy expenses, $0.06 for other operating expenses, and $0.09 in profits. This totals to $1.26 in sales revenue earned for every $1.00 spent on equipment costs. Thus, the general contractor baseline markup ($MU_{GCONTRACT_BASE}$) is 1.26.

DOE used the data in column two of Table 6.4.7 to estimate the incremental markups, after classifying the costs as either invariant or variant. At one extreme, if all of the other costs scale with the equipment price (i.e., all costs are variant), the increase in general contractor price will be $1.26, implying that the incremental markup is 1.26, or the same as the baseline markup. At the other extreme, if none of the other costs are variant, then a $1.00 increase in the equipment price will lead to a $1.00 increase in the general contractor price, for an incremental markup of 1.0. DOE believes the labor and occupancy costs are invariant, while the other operating costs and profit to scale with the equipment price (*i.e.,* are variant). In this case, for a $1.00 increase in the equipment price, the general contractor price will increase by $1.14, giving a general contractor incremental markup ($MU_{GCONTRACT_INCR}$) of 1.14.

6.5 DERIVATION OF CENSUS REGION MARKUPS

In this analysis, DOE considered six different residential boiler product classes. DOE assumed a market saturation rate for each product class that varies by geographical region defined by Residential Energy Consumption Survey (RECS)[6] and Commercial Building Energy Consumption Survey (CBECS)[7], based on the average fraction of residential boiler shipments by state from 2008 to 2012.[8] Therefore, regional markups were calculated for each residential boiler product class in both residential and commercial application.

Wholesalers and mechanical and general contractors in the residential boiler industry were divided into the 30 regions[b] provided by the latest RECS for the residential application and also were divided into the nine regions provided by the latest CBECS for the commercial application. Regional baseline and incremental markups were derived using the region/state level data from the 2013 HARDI Profit Report and the 2012 Economic Census.

6.5.1 Estimation of Wholesaler Markups

Based on the regional income statement from the 2013 HARDI Profit Report, DOE estimated baseline and incremental markups for the seven HARDI regions (Northeastern, Mid-Atlantic, Southwestern, Great Lakes, Central, Southwestern, and Western) using the methodology shown in Table 6.4.1. Next, each state in each region was assigned the HARDI regional baseline and incremental markups for the region to which it belongs. Then, DOE

[b] RECS 2009 provides 27 regions (also called reportable domains). The 27th region includes Oregon, Washington, Alaska, and Hawaii. DOE subdivided Alaska and Hawaii into separate regions (28 and 29, respectively) based on cooling and heating degree days. In addition, West Virginia, which is in RECS region 14, was disaggregated into region 30 based on cooling and heating degree days.

assigned all states to one of the 30 RECS regions used in the analysis and then calculated shipment-weighted baseline and incremental markup averages for each region in residential applications. The results are summarized in Table 6.5.1.

Table 6.5.1 Wholesaler Markups for Residential Boilers in Residential Applications

RECS 2009 Region	State(s)	Baseline MU	Incremental MU
1	Connecticut, Maine, New Hampshire, Rhode Island, Vermont	1.366	1.072
2	Massachusetts	1.366	1.072
3	New York	1.366	1.072
4	New Jersey	1.355	1.092
5	Pennsylvania	1.354	1.095
6	Illinois	1.364	1.115
7	Indiana, Ohio	1.353	1.097
8	Michigan	1.353	1.097
9	Wisconsin	1.364	1.115
10	Iowa, Minnesota, North Dakota, South Dakota	1.364	1.115
11	Kansas, Nebraska	1.364	1.115
12	Missouri	1.364	1.115
13	Virginia	1.355	1.092
14	Delaware, District of Columbia, Maryland	1.355	1.092
15	Georgia	1.330	1.097
16	North Carolina, South Carolina	1.330	1.097
17	Florida	1.330	1.097
18	Alabama, Kentucky, Mississippi	1.349	1.097
19	Tennessee	1.330	1.097
20	Arkansas, Louisiana, Oklahoma	1.348	1.112
21	Texas	1.348	1.112
22	Colorado	1.364	1.115
23	Idaho, Montana, Utah, Wyoming	1.403	1.110
24	Arizona	1.404	1.110
25	Nevada, New Mexico	1.361	1.111
26	California	1.404	1.110
27	Oregon, Washington	1.404	1.110
28	Alaska	1.404	1.110
29	Hawaii	1.404	1.110
30	West Virginia	1.353	1.097

In commercial applications, DOE assigned all states to one of the nine CBECS regions used in the analysis and then calculated shipment-weighted baseline and incremental markup averages for each region. The results are summarized in Table 6.5.2.

Table 6.5.2 Regional Wholesaler Markups for Residential Boilers in Commercial Applications

CBECS 2003 Region	Census Divisions	Baseline MU	Incremental MU
1	New England	1.366	1.072
2	Middle Atlantic	1.361	1.082
3	East North Central	1.360	1.108
4	West North Central	1.364	1.115
5	South Atlantic	1.354	1.092
6	East South Central	1.339	1.097
7	West South Central	1.348	1.112
8	Mountain	1.375	1.113
9	Pacific	1.404	1.110

6.5.2 Estimation of Mechanical Contractor Markups

The 2012 Economic Census provides Geographic Area Series for the *Plumbing and HVAC Contractors* (NAICS 23822) sector, which contains state-level sale and cost data, including value of construction, cost of subcontract work, cost of materials, and payroll for construction workers.[9] It also provides the same cost breakdown of gross margin as described in section 6.4.4.1, including labor expenses, occupancy expenses, other operating expenses, and profit. With this level of disaggregation in data available, DOE was able to estimate statewide baseline and incremental markups by using the equation mentioned in section 6.4.3. (Appendix 6A contains the full set of data.)

To estimate the baseline and incremental markups for both replacement and new construction markets for each state, DOE applied the markup deviations (*i.e.,* 3.6 percent higher and 2.2 percent lower for the replacement and new construction markets, respectively) derived in section 6.4.4.2 to the statewide baseline and incremental markups. DOE assumed that this deviation of replacement and new construction markets applies equally to the baseline and incremental markups.

Lastly, DOE divided all states among the 30 RECS regions and then calculated shipment-weighted average baseline and incremental markups for mechanical contractors for each region in residential application, as shown in Table 6.5.3.

Table 6.5.3 Shipment-Weighted Mechanical Contractor Markups for Residential Boilers in Residential Applications

RECS Regions	State(s)	Replacement Baseline MU	Replacement Incremental MU	New Construction Baseline MU	New Construction Incremental MU
1	Connecticut, Maine, New Hampshire, Rhode Island, Vermont	1.557	1.252	1.469	1.181
2	Massachusetts	1.550	1.210	1.463	1.142
3	New York	1.635	1.314	1.543	1.240
4	New Jersey	1.644	1.306	1.551	1.232
5	Pennsylvania	1.544	1.211	1.457	1.143
6	Illinois	1.603	1.217	1.513	1.149
7	Indiana, Ohio	1.587	1.256	1.497	1.185
8	Michigan	1.656	1.308	1.563	1.235
9	Wisconsin	1.513	1.174	1.428	1.108
10	Iowa, Minnesota, North Dakota, South Dakota	1.460	1.182	1.378	1.115
11	Kansas, Nebraska	1.473	1.202	1.390	1.134
12	Missouri	1.472	1.170	1.390	1.104
13	Virginia	1.592	1.299	1.502	1.226
14	Delaware, District of Columbia, Maryland	1.522	1.161	1.437	1.096
15	Georgia	1.552	1.260	1.464	1.189
16	North Carolina, South Carolina	1.528	1.242	1.442	1.172
17	Florida	1.568	1.260	1.480	1.189
18	Alabama, Kentucky, Mississippi	1.489	1.210	1.405	1.142
19	Tennessee	1.517	1.223	1.432	1.155
20	Arkansas, Louisiana, Oklahoma	1.579	1.308	1.490	1.234
21	Texas	1.528	1.239	1.442	1.169
22	Colorado	1.543	1.256	1.456	1.186
23	Idaho, Montana, Utah, Wyoming	1.521	1.222	1.436	1.153
24	Arizona	1.492	1.183	1.408	1.116
25	Nevada, New Mexico	1.501	1.214	1.417	1.146
26	California	1.629	1.307	1.538	1.234
27	Oregon, Washington	1.521	1.178	1.436	1.111
28	Alaska	1.507	1.226	1.422	1.157
29	Hawaii	1.698	1.376	1.603	1.298
30	West Virginia	1.599	1.293	1.509	1.220

In commercial application, DOE divided all states among the nine CBECS regions and then calculated shipment-weighted average baseline and incremental markups for mechanical contractors for each region, as shown in Table 6.5.4.

Table 6.5.4 Shipment-Weighted Mechanical Contractor Markups for Residential Boilers in Commercial Applications

CBECS Regions	Census Divisions	Replacement Baseline MU	Replacement Incremental MU	New Construction Baseline MU	New Construction Incremental MU
1	New England	1.554	1.235	1.467	1.165
2	Middle Atlantic	1.617	1.290	1.526	1.217
3	East North Central	1.587	1.232	1.498	1.163
4	West North Central	1.462	1.182	1.379	1.115
5	South Atlantic	1.540	1.197	1.453	1.130
6	East South Central	1.504	1.217	1.419	1.149
7	West South Central	1.557	1.279	1.470	1.207
8	Mountain	1.530	1.239	1.444	1.170
9	Pacific	1.539	1.205	1.452	1.137

6.5.3 Estimation of General Contractor Markups

In order to derive regional general contractor markups for the residential building construction sector from the 2012 Economic Census, DOE combined four Geographic Area Series: (1) *New Single-Family General Contractors* (NAICS 236115), (2) *New Multifamily Housing Construction* (NAICS 236116), (3) *New Housing Operative Builders* (NAICS 236117), and (4) *Residential Remodelers* (NAICS 236118). Similarly, DOE used the Commercial Building Construction series (NAICS 236220) from the 2012 Economic Census to derive regional general contractor markups for the commercial application of residential boilers.

For the residential building construction sector, each series consists of state-level cost data required to calculate only baseline markups for each state, as illustrated in Section 6.4.3, but not incremental markups. Alternatively, DOE calculated the ratio of average baseline and incremental markups for residential general contractor at national level and found that the incremental markup is around 17.5 percent lower than the baseline markups. DOE further derived the state-level incremental markups by applying this ratio to the baseline markup in each state, assuming that this deviation applies equally to all states. On the other hand, the type of cost data required to develop baseline and incremental markups are available for commercial building construction sector; therefore, DOE used similar approach as described in section 6.5.2 to estimate state-level baseline and incremental markup for commercial general contractors. Lastly, DOE divided all states among the 30 RECS regions and nine CBECS regions; then calculated shipment-weighted average baseline and incremental markups for general contractors for each region in both residential and commercial application. The final results are summarized in Table 6.5.5 for residential application Table 6.5.6 for commercial application (Appendix 6A contains the full set of data.)

Table 6.5.5 General Contractor Markups for Residential Boilers in Residential Applications

RECS Regions	State(s)	Baseline MU	Incremental MU
1	Connecticut, Maine, New Hampshire, Rhode Island, Vermont	1.344	1.109
2	Massachusetts	1.265	1.044
3	New York	1.334	1.101
4	New Jersey	1.434	1.183
5	Pennsylvania	1.413	1.166
6	Illinois	1.322	1.091
7	Indiana, Ohio	1.336	1.102
8	Michigan	1.526	1.259
9	Wisconsin	1.263	1.042
10	Iowa, Minnesota, North Dakota, South Dakota	1.272	1.050
11	Kansas, Nebraska	1.304	1.076
12	Missouri	1.319	1.089
13	Virginia	1.428	1.178
14	Delaware, District of Columbia, Maryland	1.570	1.296
15	Georgia	1.363	1.125
16	North Carolina, South Carolina	1.284	1.060
17	Florida	1.418	1.170
18	Alabama, Kentucky, Mississippi	1.374	1.134
19	Tennessee	1.383	1.141
20	Arkansas, Louisiana, Oklahoma	1.320	1.089
21	Texas	1.358	1.120
22	Colorado	1.280	1.056
23	Idaho, Montana, Utah, Wyoming	1.288	1.063
24	Arizona	1.388	1.145
25	Nevada, New Mexico	1.360	1.122
26	California	1.400	1.155
27	Oregon, Washington	1.320	1.089
28	Alaska	1.302	1.074
29	Hawaii	1.227	1.013
30	West Virginia	1.384	1.142

Table 6.5.6 General Contractor Markups for Residential Boilers in Commercial Applications

CBECS Regions	Census Division	Baseline MU	Incremental MU
1	New England	1.296	1.167
2	Middle Atlantic	1.313	1.174
3	East North Central	1.213	1.104
4	West North Central	1.238	1.127
5	South Atlantic	1.300	1.189
6	East South Central	1.246	1.145
7	West South Central	1.229	1.128
8	Mountain	1.206	1.080
9	Pacific	1.276	1.145

6.6 SALES TAX

The sales tax represents state and local sales taxes that are applied to the consumer price of the equipment. The sales tax is a multiplicative factor that increases the consumer equipment price. DOE only applied the sales tax to the consumer price of the equipment in the replacement market, not the new construction market. The common practice for selling larger residential appliances like boilers in the new construction market is that general contractors (or builders) bear the added sales tax for equipment, in addition to the cost of equipment, and then mark up the entire cost in the final listing price to consumers. Therefore, no additional sales tax is necessary to calculate the consumer equipment price for the new construction market.

DOE derived state and local taxes from data provided by the Sales Tax Clearinghouse.[10] These data represent weighted averages that include county and city rates. DOE then derived shipment-weighted average tax values for each RECS 2009 and CBECS 2003 region to match the regional markups for wholesalers and mechanical and general contractors, as shown in Table 6.6.1 and Table 6.6.2. Detailed sales tax data by each state can be found in appendix 6A.

Table 6.6.1 Average Sales Tax Rates by RECS 2009 Region

RECS 2009 Region	State(s)	Fraction of Total Shipments (2008-2012) %	Tax Rate (2013) %
1	Connecticut, Maine, New Hampshire, Rhode Island, Vermont	16.0	5.72
2	Massachusetts	11.3	5.50
3	New York	25.6	6.95
4	New Jersey	10.5	7.95
5	Pennsylvania	10.1	8.45
6	Illinois	3.4	4.35
7	Indiana, Ohio	2.2	6.66
8	Michigan	1.8	6.00
9	Wisconsin	2.4	5.60
10	Iowa, Minnesota, North Dakota, South Dakota	3.1	7.12
11	Kansas, Nebraska	0.1	7.27
12	Missouri	0.2	7.20
13	Virginia	1.8	7.95
14	Delaware, District of Columbia, Maryland	5.5	8.76
15	Georgia	0.0	6.65
16	North Carolina, South Carolina	0.2	6.75
17	Florida	0.0	5.75
18	Alabama, Kentucky, Mississippi	0.1	6.86
19	Tennessee	0.1	7.00
20	Arkansas, Louisiana, Oklahoma	0.1	7.95
21	Texas	0.1	7.20
22	Colorado	1.5	8.45
23	Idaho, Montana, Utah, Wyoming	0.7	6.10
24	Arizona	0.1	0.00
25	Nevada, New Mexico	0.4	0.00
26	California	0.5	8.95
27	Oregon, Washington	2.0	6.76
28	Alaska	0.3	1.30
29	Hawaii	0.0	7.05
30	West Virginia	0.1	6.10
Shipment-Weighted National Average			**8.85**

Table 6.6.2 Average Sales Tax Rates by CBECS 2003 Region

CBECS 2003 Region	Census Divisions	Fraction of Total Shipments (2008-2012) %	Tax Rate (2014) %
1	New England	27.3	5.63%
2	Middle Atlantic	46.1	7.50%
3	East North Central	9.8	5.48%
4	West North Central	3.4	7.13%
5	South Atlantic	7.5	8.49%
6	East South Central	0.2	6.93%
7	West South Central	0.2	7.63%
8	Mountain	2.7	6.46%
9	Pacific	2.7	6.61%
Shipment-Weighted National Average			**8.85**

6.7 OVERALL MARKUPS

The overall markup for each distribution channel is the product of the appropriate markups, as well as the sales tax in the case of replacement applications (Table 6.7.1 and Table 6.7.2).

DOE used the overall baseline markup to estimate the consumer product price of baseline models, given the manufacturer cost of the baseline models. As stated previously, DOE considers baseline models to be products sold under existing market conditions (*i.e.,* without new energy conservation standards). The following equation shows how DOE used the overall baseline markup to determine the product price for baseline models.

$$CPP_{BASE} = COST_{MFG} \times \left(MU_{MFG} \times MU_{BASE} \times Tax_{SALES}\right) = COST_{MFG} \times MU_{OVERALL_BASE}$$

Eq. 6.6

Where:

CPP_{BASE} = consumer product price for baseline models,
$COST_{MFG}$ = manufacturer cost for baseline models,
MU_{MFG} = manufacturer markup,
MU_{BASE} = baseline replacement or new home channel markup,
Tax_{SALES} = sales tax (replacement applications only), and
$MU_{OVERALL_BASE}$ = baseline overall markup.

Similarly, DOE used the overall incremental markup to estimate changes in the consumer product price, given changes in the manufacturer cost from the baseline model cost resulting from an energy conservation standard to raise product energy efficiency. The total consumer product price for more energy-efficient models is composed of two components: the consumer product price of the baseline model and the change in consumer product price associated with the increase in manufacturer cost to meet the new energy conservation standard. The following

equation shows how DOE used the overall incremental markup to determine the consumer product price for more energy-efficient models (*i.e.,* models meeting new energy conservation standards).

$$\begin{aligned} CPP_{STD} &= COST_{MFG} \times MU_{OVERALL_BASE} + \Delta COST_{MFG} \times \left(MU_{MFG} \times MU_{INCR} \times Tax_{SALES}\right) \\ &= CPP_{BASE} + \Delta COST_{MFG} \times MU_{OVERALL_INCR} \end{aligned}$$

Eq. 6.7

Where:

CPP_{STD} = consumer product price for models meeting new energy conservation standards,
CPP_{BASE} = consumer product price for baseline models,
$COST_{MFG}$ = manufacturer cost for baseline models,
$\Delta COST_{MFG}$ = change in manufacturer cost for more energy-efficient models,
MU_{MFG} = manufacturer markup,
MU_{INCR} = incremental replacement or new home channel markup,
Tax_{SALES} = sales tax (replacement applications only),
$MU_{OVERALL_BASE}$ = baseline overall markup (product of manufacturer markup, baseline replacement or new home channel markup, and sales tax), and
$MU_{OVERALL_INCR}$ = incremental overall markup.

National weighted average baseline and incremental markups for each market participant are summarized in Table 6.7.1 and Table 6.7.2 for residential boilers. These values represent the weighted average markups based on the state-level markup values and shipment data by state as weight. Based on residential boiler shipment forecasts for the year 2021 (see chapter 9), DOE estimated that 9 percent of gas-fired hot water boilers, 4 percent of oil-fired hot water boilers, 18 percent of electric hot water boilers, and 0 percent of gas-fired, oil-fired, and electric steam boilers go to new construction, as opposed going to the replacement market. By weighing the markups by the market shares for each type of residential boiler and market, total markups are listed in Table 6.7.3.

Table 6.7.1 Summary of Overall Markups on Residential Boilers in Residential Applications

	Replacement		New Construction	
	Baseline Markup	**Incremental Markup**	**Baseline Markup**	**Incremental Markup**
Manufacturer	1.41		1.41	
Wholesaler	1.35	1.10	1.35	1.10
Mechanical Contractor	1.56	1.25	1.47	1.18
General Contractor	--	--	1.36	1.23
Sales Tax	1.09	1.09	--	--
Overall Markup	3.25	2.12	3.83	2.26

Table 6.7.2 Summary of Overall Markups on Residential Boilers in Commercial Applications

	Replacement			New Construction		
	Baseline Markup	**Incremental Markup**	**National Account: Baseline/ Incr. MU**	**Baseline Markup**	**Incremental Markup**	**National Account: Baseline/ Incr. MU**
Manufacturer	1.41			1.41		
Wholesaler	1.35	1.10	1.35/1.10	1.35	1.10	1.35/1.10
Mechanical Contractor	1.56	1.25	--	1.47	1.18	--
General Contractor	--	--	--	1.26	1.14	--
Sales Tax	1.09	1.09	1.09	--	--	1.09
Overall Markup	3.25	2.12	2.09/1.70	3.55	2.09	2.09/1.70

Table 6.7.3 Summary of Total Markup by Residential Boiler Product Class

Product Class	Baseline Markup	Incremental Markup
Gas-fired hot water boiler	3.30	2.05
Gas-fired steam boiler	3.24	2.05
Oil-fired hot water boiler	3.24	2.03
Oil-fired steam boiler	3.23	2.03
Electric hot water boiler	3.19	2.01
Electric steam boiler	3.14	2.03

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APPENDIX 6A. DETAILED DATA FOR PRODUCT PRICE MARKUPS

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APPENDIX 6A. DETAILED DATA FOR PRODUCT PRICE MARKUPS

6A.1 DETAILED WHOLESALER COST DATA

Based on data provided by the Heating Air-conditioning & Refrigeration Distributors International (HARDI), Table 6.4.1 of chapter 6 shows wholesaler revenues and costs in aggregated form. Table 6A.1.1 in this appendix provides the complete breakdown of costs and expenses. The column labeled "Scaling" in Table 6A.1.1 indicates which expenses the U.S. Department of Energy (DOE) assumed to scale with only the baseline markup and which with both the baseline and incremental markups. As described in chapter 6, only those expenses that scale with both baseline and incremental costs are marked up when there is an incremental change in equipment costs.

Table 6A.1.1 Disaggregated Costs and Expenses for Wholesalers

Item	Percent of Revenue %	Scaling
Cost of Goods Sold	**73.9**	
Gross Margin	**26.1**	
Payroll Expenses	**15.1**	Baseline
Executive Salaries & Bonuses	1.6	
Branch Manager Salaries and Commissions	1.3	
Sales Executive Salaries & Commissions	0.5	
Outside Sales Salaries & Commissions	2.3	
Inside/Counter Sales/Wages	2.6	
Purchasing Salaries/Wages	0.5	
Credit Salaries/Wages	0.2	
IT Salaries/Wages	0.2	
Warehouse Salaries/Wages	1.4	
Accounting	0.5	
Delivery Salaries/Wages	0.8	
All Other Salaries/Wages & Bonuses	0.8	
Payroll Taxes	1.0	
Group Insurance	1.0	
Benefit Plans	0.4	
Occupancy Expenses	**3.5**	Baseline
Utilities: Heat, Light, Power, Water	0.4	
Telephone	0.3	
Building Repairs & Maintenance	0.3	
Rent or Ownership in Real Estate	2.5	

Item	Percent of Revenue %	Scaling
Other Operating Expenses	**5.2**	Baseline & Incremental
Sales Expenses (incl. advertising & promotion)	0.9	
Insurance (business liability & casualty)	0.2	
Depreciation	0.4	
Vehicle Expenses	1.2	
Personal Property Taxes/Licenses	0.1	
Collection Expenses	0.3	
Bad Debt Losses	0.2	
Data Processing	0.3	
All Other Operating Expenses	1.5	
Total Operating Expenses	**23.8**	
Operating Profit	**2.3**	Baseline & Incremental
Other Income	0.4	
Interest Expense	0.4	
Other Non-operating Expenses	0.0	
Profit Before Taxes	**2.3**	

Source: Heating, Air-conditioning & Refrigeration Distributors International. 2013. 2013 Profit Report (2012 Data).
Note: The wholesaler costs and expenses are percentage values as opposed to the per-dollar of sales revenue values shown in chapter 6.

6A.2 DETAILED MECHANICAL CONTRACTOR DATA

Chapter 6 provides mechanical contractor revenues and costs in aggregated form by 'Cost of Goods Sold' and 'Gross Margin.' The tables are based on data in the 2005 edition of *Financial Analysis for the HVACR Contracting Industry,* published by the Air Conditioning Contractors of America (ACCA). The ACCA report did not provide a more disaggregated tabulation of these costs and expenses. As in section 6A.1, the gross margin category was assumed to scale only with the baseline markup.

A further disaggregated breakdown of costs used to scale the incremental markup is shown in Table 6A.2.1 by both dollar value and percentage terms from the 2012 Census of Business. As the ACCA data were used to calculate the baseline markup, in Table 6A.2.1 only the categories in the 'Scaling' column that are scaled with both the baseline and incremental markups are marked when there is an incremental change in equipment costs.

Table 6A.2.1 Mechanical Contractor Expenses and Markups Used To Scale the Incremental Markups

Item	Dollar Value $1,000	Percentage %	Scaling
Total Cost of Equipment Sales	**97,926,266**	**66.37**	
Total payroll, construction workers wages	28,352,603	19.22	
Cost of materials, components, and supplies	51,896,103	35.17	
Cost of construction work subcontracted out to others	14,726,652	9.98	
Total cost of selected power, fuels, and lubricants	2,950,908	2.00	
Gross Margin	**49,621,379**	**33.63**	
Payroll Expenses	**25,777,454**	**17.47**	
Total payroll, other employee wages	13,213,745	8.96	
Total fringe benefits	12,104,730	8.20	Baseline
Temporary staff and leased employee expenses	458,979	0.31	
Occupancy Expenses	**3,801,208**	**2.58**	
Rental costs of machinery and equipment	1,062,200	0.72	
Rental costs of buildings	1,545,872	1.05	Baseline
Communication services	664,786	0.45	
Cost of repair to machinery and equipment	528,350	0.36	
Other Operating Expenses	**13,644,716**	**9.25**	
Purchased professional and technical services	903,002	0.61	
Data processing and other purchased computer services	139,701	0.09	
Expensed computer hardware and other equipment	221,937	0.15	
Expensed purchases of software	124,004	0.08	Baseline & Incremental
Advertising and promotion services	977,065	0.66	
All other expenses	6,651,228	4.51	
Refuse removal (including hazardous waste) services	182,000	0.12	
Taxes and license fees	978,852	0.66	
Total depreciation ($1,000)	3,466,927	2.35	
Net Profit Before Income Taxes	**6,398,001**	**4.34**	Baseline & Incremental

Source: U.S. Census Bureau. 2012. Plumbing, Heating, and Air-Conditioning Contractors: 2012. Sector 23: 238220. Construction: Geographic Area Series. Detailed Statistics for Establishments: 2012.
Note: Mechanical contractor costs and expenses are first presented as *total dollar* values and then converted to *percentage* values. This is in contrast to the *cost per dollar of sales revenue* values shown in chapter 6.

6A.3 DETAILED GENERAL CONTRACTOR COST DATA

Chapter 6 shows both residential building and commercial building general contractor revenues and costs in aggregated form based on U.S. Department of Census data. Table 6A.3.1 shows the complete breakdown of costs and expenses of residential building contractor provided by the U.S. Department of Census. The column labeled "Scaling" indicates which expenses DOE assumed to scale with only the baseline markup and which are scaled with both the baseline and incremental markups. Only those expenses that scale with baseline and incremental costs are marked up when there is an incremental change in product costs. Table 6A.3.2 shows the similar analysis for commercial building contractors.

Table 6A.3.1 Residential General Contractor Expenses and Markups

Item	Dollar Value *$1,000*	Percentage *%*	Scaling
Total Cost of Equipment Sales	**141,154,975**	**73.47**	
Total payroll, construction workers wages	10,234,007	5.33	
Cost of materials, components, and supplies	58,283,677	30.33	
Cost of construction work subcontracted out to others	71,108,301	37.01	
Total cost of selected power, fuels, and lubricants	1,528,990	0.80	
Gross Margin	**50,982,432**	**26.53**	
Payroll Expenses	**15,327,437**	**7.98**	Baseline
Total payroll, other employee wages	11,123,714	5.79	
Total fringe benefits	3,787,555	1.97	
Temporary staff and leased employee expenses	416,168	0.22	
Occupancy Expenses	**2,798,144**	**1.46**	Baseline
Rental costs of machinery and equipment	516,344	0.27	
Rental costs of buildings	1,361,496	0.71	
Communication services	520,340	0.27	
Cost of repair to machinery and equipment	399,964	0.21	
Other Operating Expenses	**13,806,441**	**7.19**	Baseline & Incremental
Purchased professional and technical services	1,207,647	0.63	
Data processing and other purchased computer services	95,486	0.05	
Expensed computer hardware and other equipment	177,927	0.09	
Expensed purchases of software	90,729	0.05	
Advertising and promotion services	1,202,431	0.63	
All other expenses	6,459,191	3.36	
Refuse removal (including hazardous waste) services	448,519	0.23	
Taxes and license fees	1,104,142	0.57	
Total depreciation ($1,000)	3,020,369	1.57	
Net Profit Before Income Taxes	**19,050,410**	**9.91**	Baseline & Incremental

Source: U.S. Census Bureau. 2012. Residential Building Construction. Sector 23, EC1223I1: 236115 through 236118. Construction, Industry Series, Preliminary Detailed Statistics for Establishments: 2012.
Note: General contractor costs and expenses are first presented as *total dollar* values and then converted to *percentage* values. This is in contrast to the *cost per dollar of sales revenue* values shown in chapter 6.

Table 6A.3.2 Commercial General Contractor Expenses and Markups

Item	Dollar Value *$1,000*	Percentage *%*	Scaling
Total Cost of Equipment Sales	**227,091,441**	**118.19**	
Total payroll, construction workers wages	13,739,662	7.15	
Cost of materials, components, and supplies	52,290,930	27.22	
Cost of construction work subcontracted out to others	159,555,486	83.04	
Total cost of selected power, fuels, and lubricants	1,505,363	0.78	
Gross Margin	**59,436,281**	**30.93**	
Payroll Expenses	**23,327,246**	**12.14**	
Total payroll, other employees' wages	15,668,244	8.15	
Total fringe benefits	6,992,590	3.64	
Temporary staff and leased employee expenses	666,412	0.35	Baseline
Occupancy Expenses	**3,556,983**	**1.85**	
Rental costs of machinery and equipment	1,157,567	0.60	
Rental costs of buildings	1,561,027	0.81	
Communication services	386,453	0.20	
Cost of repair to machinery and equipment	451,936	0.24	Baseline
Other Operating Expenses	**13,171,062**	**6.86**	
Purchased professional and technical services	1,369,654	0.71	
Data processing and other purchased computer services	211,790	0.11	
Expensed computer hardware and other equipment	314,009	0.16	
Expensed purchases of software	138,955	0.07	
Advertising and promotion services	387,863	0.20	
All other expenses	6,817,223	3.55	
Refuse removal (including hazardous waste) services	182,759	0.10	
Taxes and license fees	738,207	0.38	Baseline & Incremental
Total depreciation ($1,000)	3,010,602	1.57	
Net Profit Before Income Taxes	**19,380,990**	**10.09**	Baseline & Incremental

Source: U.S. Census Bureau. 2012. Residential Building Construction. Sector 23, EC1223I1: 236220 (Commercial Building Construction. Construction, Industry Series, Preliminary Detailed Statistics for Establishments: 2012.
Note: General contractor costs and expenses are first presented as *total dollar* values and then converted to *percentage* values.

6A.4 ESTIMATION OF CONTRACTOR MARK-UP BY STATE

Table 6A.4.1 Mechanical Contractor Markup Estimation by State, 2012

State	Baseline MU	Incremental MU	Replacement Baseline MU	Replacement Incremental MU	New Const. Baseline MU	New Const. Incremental MU
Alabama	1.424	1.160	1.476	1.202	1.393	1.134
Alaska	1.454	1.183	1.507	1.226	1.422	1.157
Arizona	1.440	1.142	1.492	1.183	1.408	1.116
Arkansas	1.518	1.276	1.574	1.322	1.485	1.248
California	1.572	1.261	1.629	1.307	1.538	1.234
Colorado	1.489	1.212	1.543	1.256	1.456	1.186
Connecticut	1.469	1.173	1.522	1.216	1.437	1.147
Delaware	1.601	1.253	1.659	1.299	1.566	1.226
District of Columbia	1.480	1.197	1.533	1.240	1.447	1.170
Florida	1.513	1.216	1.568	1.260	1.480	1.189
Georgia	1.497	1.216	1.552	1.260	1.464	1.189
Hawaii	1.639	1.327	1.698	1.376	1.603	1.298
Idaho	1.496	1.202	1.551	1.245	1.463	1.175
Illinois	1.547	1.175	1.603	1.217	1.513	1.149
Indiana	1.523	1.225	1.579	1.270	1.490	1.199
Iowa	1.401	1.134	1.452	1.176	1.370	1.109
Kansas	1.402	1.129	1.453	1.170	1.372	1.104
Kentucky	1.445	1.170	1.497	1.212	1.413	1.144
Louisiana	1.532	1.271	1.588	1.317	1.499	1.243
Maine	1.484	1.225	1.538	1.270	1.451	1.198
Maryland	1.464	1.115	1.517	1.156	1.432	1.091
Massachusetts	1.496	1.168	1.550	1.210	1.463	1.142
Michigan	1.598	1.262	1.656	1.308	1.563	1.235
Minnesota	1.397	1.123	1.448	1.164	1.367	1.098
Mississippi	1.391	1.163	1.441	1.205	1.360	1.137
Missouri	1.421	1.129	1.472	1.170	1.390	1.104
Montana	1.551	1.183	1.608	1.225	1.517	1.157
Nebraska	1.435	1.182	1.487	1.224	1.403	1.156
Nevada	1.510	1.191	1.565	1.234	1.477	1.165
New Hampshire	1.502	1.196	1.556	1.239	1.469	1.170
New Jersey	1.586	1.260	1.644	1.306	1.551	1.232
New Mexico	1.430	1.166	1.482	1.208	1.398	1.141

State	Baseline MU	Incremental MU	Replacement Baseline MU	Replacement Incremental MU	New Const. Baseline MU	New Const. Incremental MU
New York	1.577	1.268	1.635	1.314	1.543	1.240
North Carolina	1.464	1.185	1.517	1.228	1.431	1.159
North Dakota	1.530	1.300	1.586	1.347	1.496	1.272
Ohio	1.534	1.207	1.589	1.250	1.500	1.180
Oklahoma	1.473	1.198	1.526	1.242	1.441	1.172
Oregon	1.468	1.138	1.521	1.180	1.435	1.113
Pennsylvania	1.490	1.169	1.544	1.211	1.457	1.143
Rhode Island	1.713	1.445	1.775	1.497	1.675	1.413
South Carolina	1.558	1.300	1.615	1.347	1.524	1.271
South Dakota	1.494	1.236	1.548	1.281	1.461	1.208
Tennessee	1.464	1.181	1.517	1.223	1.432	1.155
Texas	1.474	1.196	1.528	1.239	1.442	1.169
Utah	1.363	1.165	1.412	1.207	1.333	1.139
Vermont	1.431	1.184	1.483	1.226	1.399	1.157
Virginia	1.536	1.253	1.592	1.299	1.502	1.226
Washington	1.468	1.136	1.522	1.177	1.436	1.111
West Virginia	1.543	1.248	1.599	1.293	1.509	1.220
Wisconsin	1.460	1.133	1.513	1.174	1.428	1.108
Wyoming	1.551	1.275	1.607	1.321	1.517	1.247

Sources: U.S. Bureau of the Census. American Factfinder: 2012. Sector 23: Plumbing, Heating, and Air-Conditioning Contractors (NAICS 238220), Detailed Statistics for Establishments: 2012 http://factfinder.census.gov/faces/nav/jsf/pages/index.xhtml and Geographic Area Series: Detailed Statistics for Establishments: 2012.

Table 6A.4.2 Residential Building General Contractor Markups by State

State	Value of Residential Construction *$1,000*	Cost of Goods Sold *$1,000*	Baseline Markup	Incremental Markup
Alabama	2,178,304	1,718,874	1.267	1.046
Alaska	456,428	350,552	1.302	1.074
Arizona	3,775,792	2,720,136	1.388	1.145
Arkansas	733,067	586,223	1.250	1.032
California	23,754,386	16,969,561	1.400	1.155
Colorado	4,697,132	3,669,015	1.280	1.056
Connecticut	2,065,140	1,467,636	1.407	1.161
Delaware	531,489	280,853	1.892	1.562
District of Columbia	540,500	437,726	1.235	1.019
Florida	14,741,311	10,396,009	1.418	1.170

State	Value of Residential Construction *$1,000*	Cost of Goods Sold *$1,000*	Baseline Markup	Incremental Markup
Georgia	5,079,494	3,726,043	1.363	1.125
Hawaii	1,201,352	978,972	1.227	1.013
Idaho	1,131,398	900,465	1.256	1.037
Illinois	4,941,309	3,738,923	1.322	1.091
Indiana	2,932,444	2,367,239	1.239	1.022
Iowa	803,423	616,991	1.302	1.075
Kansas	1,140,422	883,857	1.290	1.065
Kentucky	1,495,936	1,090,711	1.372	1.132
Louisiana	1,418,049	1,085,242	1.307	1.078
Maine	712,700	569,144	1.252	1.033
Maryland	5,651,161	3,621,491	1.560	1.288
Massachusetts	4,855,693	3,838,971	1.265	1.044
Michigan	4,184,708	2,741,904	1.526	1.259
Minnesota	3,597,247	2,870,763	1.253	1.034
Mississippi	449,478	306,474	1.467	1.210
Missouri	1,999,325	1,515,274	1.319	1.089
Montana	694,346	558,319	1.244	1.026
Nebraska	1,101,047	838,567	1.313	1.084
Nevada	1,916,050	1,234,905	1.552	1.280
New Hampshire	589,935	447,414	1.319	1.088
New Jersey	7,613,380	5,310,328	1.434	1.183
New Mexico	888,942	682,676	1.302	1.075
New York	12,082,752	9,056,001	1.334	1.101
North Carolina	6,563,319	5,076,655	1.293	1.067
North Dakota	605,023	464,544	1.302	1.075
Ohio	4,292,128	3,129,309	1.372	1.132
Oklahoma	1,503,337	1,044,379	1.439	1.188
Oregon	2,423,321	1,710,353	1.417	1.169
Pennsylvania	6,425,643	4,548,516	1.413	1.166
Rhode Island	476,279	348,853	1.365	1.127
South Carolina	3,338,827	2,738,502	1.219	1.006
South Dakota	259,209	205,006	1.264	1.043
Tennessee	2,811,396	2,033,435	1.383	1.141
Texas	22,163,108	16,326,369	1.358	1.120
Utah	1,952,506	1,460,259	1.337	1.103

State	Value of Residential Construction *$1,000*	Cost of Goods Sold *$1,000*	Baseline Markup	Incremental Markup
Vermont	492,744	375,852	1.311	1.082
Virginia	7,841,341	5,492,481	1.428	1.178
Washington	5,747,314	4,402,529	1.305	1.077
West Virginia	155,187	112,098	1.384	1.142
Wisconsin	2,683,336	2,125,251	1.263	1.042
Wyoming	550,391	404,756	1.360	1.122

Sources: U.S. Bureau of the Census, American Factfinder. 2012 Economic Census. Sector 23: Subsectors 236115 (residential single-family), 236116 (residential multifamily), 236117 (operative builders), and 236118 (residential remodelers). Sector 23: EC0723A1: Construction: Geographic Area Series: Detailed Statistics for Establishments: 2012.

Table 6A.4.3 Commercial Building General Contractor Baseline Markups by State

State	Value of Construction *$1,000*	Cost of Goods Sold *$1,000*	Baseline Markup	Incremental Markup
Alabama	5,625,853	4,259,214	1.321	1.212
Alaska	1,930,489	1,264,258	1.527	1.295
Arizona	5,671,837	4,671,800	1.214	1.096
Arkansas	2,240,780	1,738,483	1.289	1.205
California	33,551,787	25,469,257	1.317	1.183
Colorado	6,088,761	5,266,098	1.156	1.014
Connecticut	3,192,435	2,295,574	1.391	1.256
Delaware	547,689	451,900	1.212	1.091
District of Columbia	788,454	600,743	1.312	1.172
Florida	11,718,320	9,277,654	1.263	1.132
Georgia	8,930,039	7,792,862	1.146	1.052
Hawaii	2,287,415	1,514,954	1.510	1.344
Idaho	1,332,964	1,078,555	1.236	1.125
Illinois	12,116,732	10,220,218	1.186	1.089
Indiana	4,232,698	3,540,925	1.195	1.072
Iowa	3,414,196	2,789,006	1.224	1.115
Kansas	2,360,940	1,880,555	1.255	1.158
Kentucky	2,096,059	1,687,300	1.242	1.133
Louisiana	3,857,308	3,085,988	1.250	1.147
Maine	537,321	476,588	1.127	1.017
Maryland	10,394,811	8,048,916	1.291	1.182
Massachusetts	8,797,538	6,716,220	1.310	1.172
Michigan	6,597,430	5,536,996	1.192	1.099
Minnesota	7,202,161	5,790,770	1.244	1.129
Mississippi	2,255,697	1,704,388	1.323	1.200

Missouri	7,385,012	6,018,675	1.227	1.100
Montana	777,086	608,534	1.277	1.161
Nebraska	1,719,205	1,333,949	1.289	1.170
Nevada	2,372,887	1,488,212	1.594	1.470
New Hampshire	905,873	749,012	1.209	1.090
New Jersey	5,511,034	3,983,083	1.384	1.219
New Mexico	1,378,782	1,142,990	1.206	1.100
New York	21,697,018	16,634,089	1.304	1.169
North Carolina	6,181,677	5,127,565	1.206	1.090
North Dakota	1,056,945	836,829	1.263	1.173
Ohio	9,757,775	7,686,037	1.270	1.157
Oklahoma	3,502,861	2,933,386	1.194	1.110
Oregon	3,622,635	3,177,363	1.140	1.059
Pennsylvania	11,228,852	8,908,802	1.260	1.142
Rhode Island	1,765,596	1,150,426	1.535	1.423
South Carolina	2,310,054	1,781,480	1.297	1.176
South Dakota	967,246	796,904	1.214	1.134
Tennessee	5,646,576	4,575,627	1.234	1.142
Texas	24,704,537	20,483,963	1.206	1.103
Utah	4,046,880	3,229,309	1.253	1.169
Vermont	433,855	321,724	1.349	1.196
Virginia	8,218,957	6,105,870	1.346	1.234
Washington	6,877,191	5,521,475	1.246	1.123
West Virginia	583,873	456,824	1.278	1.145
Wisconsin	5,613,331	4,545,544	1.235	1.104
Wyoming	487,371	373,179	1.306	1.198

Sources: U.S. Bureau of the Census, American Factfinder. 2012 Economic Census. Sector 23: Subsectors 236220 (Commercial Building Construction). Sector 23: EC0723A1: Construction: Geographic Area Series: Detailed Statistics for Establishments: 2012.
Notes: The Census Bureau withheld data for some states.

6A.5 STATE SALES TAX RATES

Table 6A.5.1 State Sales Tax Rates

State	Combined State and Local Tax Rate %	State	Combined State and Local Tax Rate %	State	Combined State and Local Tax Rate %
Alabama	8.65	Kentucky	6.00	North Dakota	6.10
Alaska	1.30	Louisiana	8.90	Ohio	7.15
Arizona	7.20	Maine	5.50	Oklahoma	8.45
Arkansas	8.95	Maryland	6.00	Oregon	--
California	8.45	Massachusetts	6.25	Pennsylvania	6.35
Colorado	6.10	Michigan	6.00	Rhode Island	7.00
Connecticut	6.35	Minnesota	7.20	South Carolina	7.20
Delaware	--	Mississippi	7.05	South Dakota	5.45
Dist. of Columbia	5.75	Missouri	7.45	Tennessee	9.45
Florida	6.65	Montana	--	Texas	7.95
Georgia	7.05	Nebraska	6.05	Utah	6.70
Hawaii	4.35	Nevada	7.95	Vermont	6.10
Idaho	6.00	New Hampshire	--	Virginia	5.60
Illinois	8.05	New Jersey	6.95	Washington	8.85
Indiana	7.00	New Mexico	6.80	West Virginia	6.15
Iowa	6.80	New York	8.45	Wisconsin	5.45
Kansas	8.30	North Carolina	6.90	Wyoming	5.45

Source: The Sales Tax Clearinghouse at https://thestc.com/STRates.stm (Accessed on September 1, 2015).

6A.6 DATA FOR MARKUP COMPARISON

DOE performed an analysis of the accuracy of the overall markups estimated for baseline residential boilers by comparing the online retail price with DOE's estimated retail price in each product class. DOE collected online retail prices along with detailed product characteristics from four main residential boiler online retailers: eComfort, SupplyHouse.com, Younits, and SustainableSupply.com.[1,2,3,4] Based on product attributes, including input capacity, AFUE, fuel type, and heat medium, DOE was able to assign product class and efficiency level for all models and calculated the average retail price for the baseline models in each product class. However, the sample size of oil-fired hot water boilers and gas-fired and oil-fired steam residential boilers collected was too small to make robust price comparison; therefore, DOE only compared the price of gas-fired hot water boilers in this analysis.

It is believed that the distribution for online retailers is different from the conventional distribution channel. Hence, in order to have the DOE's estimated prices comparable to the online retail price, DOE constructed a separate set of prices based on the manufacturer production cost[a] and applied the manufacturer markup, wholesaler markup, and mechanical contractor markup to derive the estimated retail prices. This markup represents the replacement distribution channel as described in chapter 6, Markups to Determine Product Cost. The result of

[a] DOE excluded models with a draft inducer from both its estimated price and the retail price data.

comparing the online average retail prices and DOE's estimated prices is summarized in Table 6A.6.1. These estimates do not include sales taxes or shipping costs.

Table 6A.6.1 Price Comparison of Baseline Residential Boilers

Product Class	Baseline AFUE *(%)*	AFUE range of Retail Prices *(%)*	Average Online Retail Price – for 96-105 kBtu/h (2014$)	DOE's Estimated Price for 100 kBtu/h (2014$)
Gas-fired Hot Water Boiler	82	82 to 82.3	1,753.83	1,899.31

Although DOE's estimated prices for gas-fired hot water boilers are not exactly the same as the average online retail price, they are not too different from each other. As another comparison point, multiplying the 2015 RS Means5 equipment price value of a similar baseline model ($1,975) by a 10-percent contractor markup results in a boiler price of approximately $2,172.50. DOE's estimated price for gas-fired hot water boilers falls within the range of online average retail price and RS Means' estimated prices. Detailed model information used in the comparison is presented in Table 6A.6.2 below.

Table 6A.6.2 List of Residential Hot Water Gas Boiler Prices from Online Websites

Manufacturer	Model Number	AFUE *(%)*	Input Capacity *(kBTU)*	Online Store	Sales Price *(2014$)*
Burnham	204NI-T2	82.3	96	eComfort	1,968.95
Peerless	MI-04-SPRK-WPC-N	82.1	105	eComfort	2,022.76
New Yorker	CG40DNI-T2	82.3	96	eComfort	1,769.04
Pennco	15B096FE	82.0	96	Younits	1,689.50
New Yorker	CG40DNI-L2 & Taco Pump[b]	82.3	96	Younits	1,651.53
New Yorker	CG40DNI-L2 & Taco Pump[c]	82.3	96	eComfort	1,496.72
New Yorker	CG40DNI-G2	82.3	96	SupplyHouse	1,478.64
Burnham	P204-EI-NG	82.3	96	SupplyHouse	2,267.95
Peerless	MI-04-SPRK-WPC-N	82.1	105	SupplyHouse	1,768.39
Hydrotherm	HWX-105-INT	82.1	105	SustainableSupply	1,834.43

[b] The total price of this mode includes a basic model ($1,568.61) and a separate Taco Pump ($82.93)
[c] The total price of this mode includes a basic model ($1,368.43) and a separate Taco Pump ($128.29)

REFERENCES

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APPENDIX 6B. INCREMENTAL MARKUPS: THEORY AND EVIDENCE

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APPENDIX 6B. INCREMENTAL MARKUPS: THEORY AND EVIDENCE

6B.1 INTRODUCTION

Since 2004, the Department of Energy (DOE) has applied the incremental markup approach to estimate the increase in final product price of high-efficiency products as a function of the increase in manufacturing cost.[1] Under this approach, DOE applies a lower markup than the average markup to the incremental cost of higher-efficiency products, relative to the baseline product. The approach is described in detail in chapter 6.

DOE's incremental markup approach is based on the widely accepted economic view that prices closely reflect marginal costs in competitive markets and in those with some degree of concentration. Evaluating industry data in IBISWorld suggests that most of the industries relevant to HVAC wholesalers and contractors are considered to have low market concentration, high and increasing market competition and low to medium barriers to entry (see Table 6B.1).[2]

Table 6B.1 Competitive Environment of HVAC Sectors

Sector	Industry Concentration	Competition	Barriers to Entry
Home builders	Low	High and increasing	Low and steady
Commercial building construction	Low	High and steady	Medium and steady
Heating & air-conditioning contractors	Low	High and increasing	Medium and steady
Heating & air-conditioning wholesaling	Low	High and increasing	Medium and increasing

Examining gross margin and price data in HVAC wholesale industry over time, DOE finds that both gross margins and prices did not demonstrate any persistent trend; thus, this set of historical data has no bearing on firm markup behavior under product price increases, such as may occur as a result of standards.

To investigate markup behavior under product price increases, DOE evaluated time series gross margin data from three industries with rapidly changing input prices – the LCD television retail market, the U.S. oil and gasoline market, and the U.S. housing market. Additionally, DOE conducted an in-depth interview with an HVAC consultant who represents many individual contractors in the industry.

6B.2 MARGIN TRENDS UNDER PRICE VOLATILITY

Heating, Air-Conditioning and Refrigeration Distributors International (HARDI) published annual profit report with aggregated financial and operating data of its participating firms in HVAC wholesale industry. DOE evaluated the percent gross margins[a] and sales revenue per shipment received (as a proxy for average HVAC wholesale prices) reported from 1999 to 2012 for typical HARDI distributors.[b] As shown in Figure 6B.1, average HVAC wholesaler prices have experienced some fluctuations during this period of time, but the overall wholesale price trend is relatively stable, with a price increase of four percent from 1999 to 2012.

However, the existence of constant percent margin over time is not sufficient to identify an industry's markup practice without considering the underlying input price changes during the same period. If the prices have been relatively constant, the incremental markup approach will arrive at the same result as applying constant margin. In fact, the average HVAC wholesale prices have been relatively stable over time;[c] hence, the historically constant percent margins do not necessarily imply a constant percent margin in the future, especially in the case of increased input prices due to standards (Figure 6B.1).

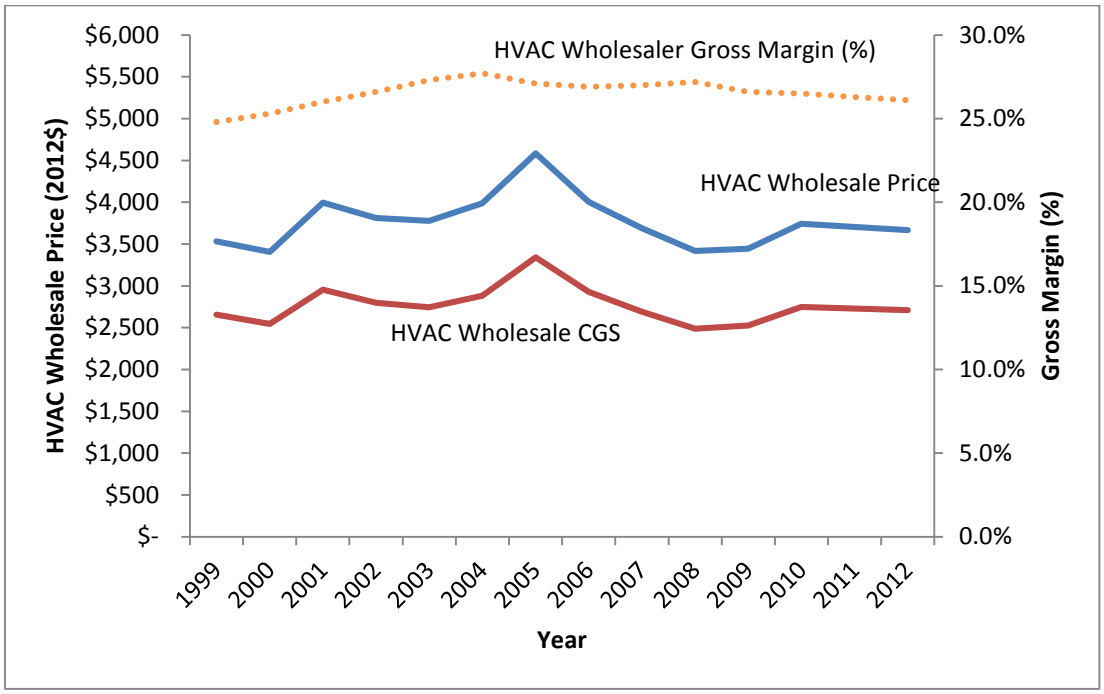

Figure 6B.1 HVAC Wholesale Prices, Cost of Goods Sold and Gross Margins

As historical data in HVAC wholesale markets cannot be used to address the question of margins under a price shock, DOE looked to other publicly available data for markets of a single

[a] Percent gross margin is defined as gross margin in percentage of sales revenue.
[b] The typical distributors are the firms with median financial results among all participating firms.
[c] In 2005 the HVAC market experienced a brief 15-percent price rise. The HVAC price increase may be attributed to the 2006 Central Air-Conditioner and Heat Pump Standard. Gross margins declined slightly at this time.

product that have experienced noticeable price changes, evaluating the prevalence of fixed percent gross margins.

To replicate the theorized conditions of efficiency standard implementation, DOE would ideally analyze a household durable that has experienced a consistent rise in price, such as may occur as a result of standards. The LCD television retail market, on the other hand, is a market with a consistently downward price trend since 2007. The material costs and retail prices of LCD televisions have both dropped substantially over this period. At the same time, average retailer gross margins have decreased from 25 percent in 2007 to only 6 percent in late 2014. Under the change in input price (*i.e.*, cost of goods sold (CGS)), retailers did not maintain constant percent gross margins (Figure 6B.2).[d]

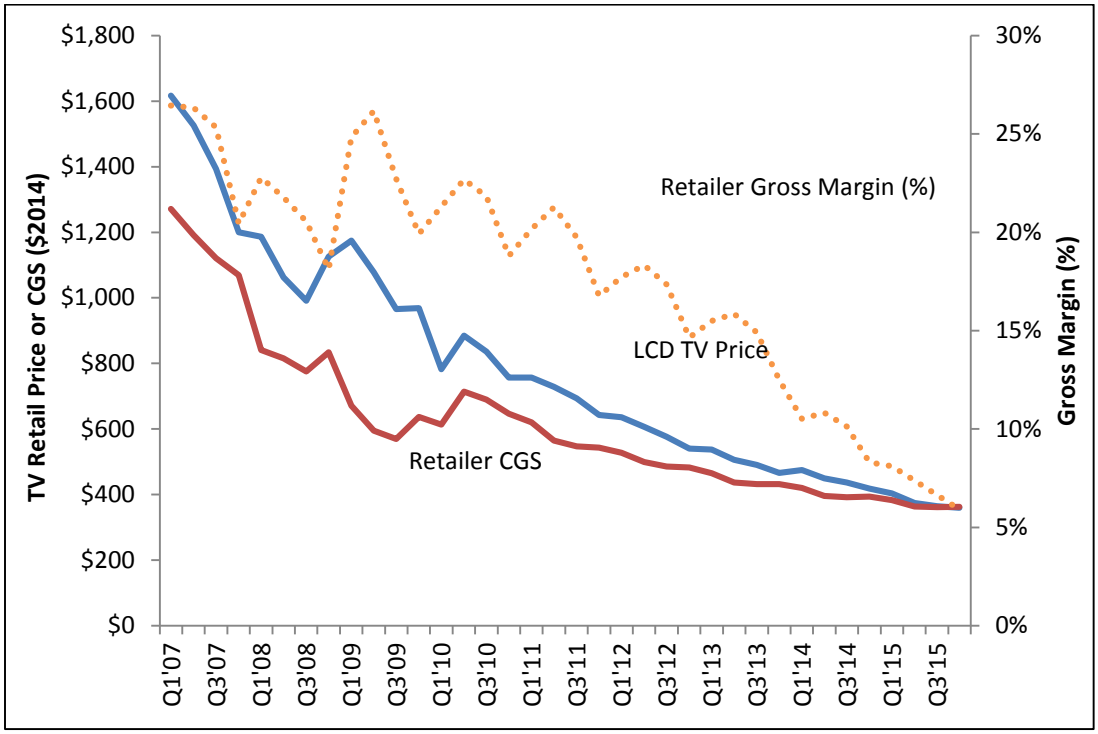

Figure 6B.2 LCD TV Prices, Cost of Goods Sold and Gross Margins

DOE also analyzed margin behavior in markets with upward price trends to test the prevalence of fixed percent gross margins. U.S. imported crude oil prices rose by $2.50 per gallon from 1995 to 2008, but the percent retail gross margins have decreased during the same period of time (Figure 6B.3). [3]

[d] LCD television data from DisplaySearch, a market research company affiliated with NPD Group.

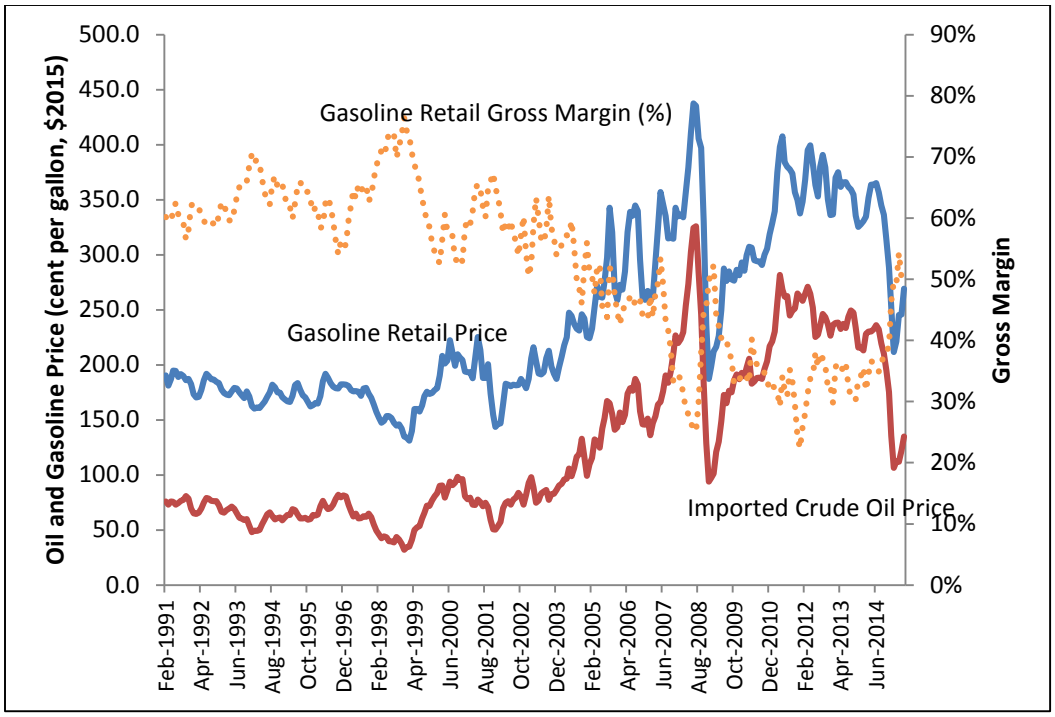

Figure 6B.3 Oil and Gasoline Price, Gross Margin

The U.S. inflation-adjusted median home sales prices and the costs of selling, measured by home sales price minus agent's commission fee, have increased substantially from 1991 to 2005. The percent gross margin in the housing market (*i.e.*, commission rate), however, has declined by 15 percent over this period (Figure 6B.4).[4–7,e] In short, fixed percent gross margins are not observed in this market with increasing costs.

[e] Federal Trade Commission and the U.S. Department of Justice published a report, titled "Competition in the Real Estate Brokerage Industry", which provides extensive literature review on the topic of housing prices and brokerage commission fee, and the empirical evidences are consistent with our findings. Access to the full report: https://www.ftc.gov/reports/competition-real-estate-brokerage-industry-report-federal-trade-commission-us-department

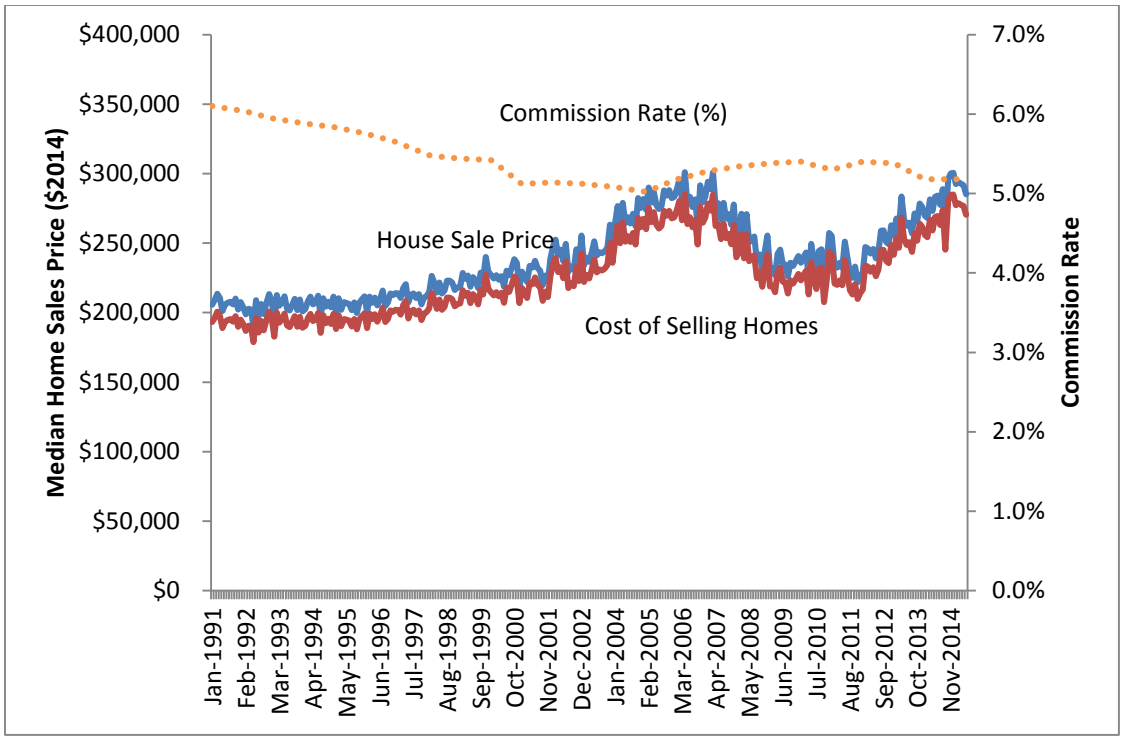

Figure 6B.4 House Sales Price, Costs of Selling Homes, and Realtor Commission (%)

After examining price and gross margin data in various markets, the results indicate that prices could go up or down in different circumstances, but in no case are percent gross margins observed to remain fixed over time. Hence, DOE does not expect that firms can sustain on applying constant markups on incremental costs of more efficient products after standards.

6B.3 SUMMARY OF CONSULTANT INTERVIEW

To gain insight into contractor markup determination, DOE interviewed an experienced consultant who specializes in the HVAC contracting field.[8] Because the incremental markup is applied in a very specific analytical situation where the input cost increases due to the standard while other costs remain the same, it was necessary to carefully craft the interview to accurately convey the concept. The list of key questions asked of the consultant includes the following points:

1. *Assuming the HVAC equipment price increases while the other costs remain constant (no change in labor, material, and operating costs), are contractors still able to keep the same markup over time as before?*
2. *Keeping a fixed markup when the equipment price goes up implies that the contractor's profitability would increase, assuming no other cost changes. Is this increase in profitability viable over time?*
3. *If contractors would have to adjust their markup in this situation due to competition, how long does it take for them to revisit their markup values and adjust the firm's profitability to a competitive level?*

The consultant responded as follows:

1. *Initially, contractors will attempt to use the same markup after the increase in input cost occurs, but, assuming there is no increase in other costs, "they'll eventually either have to lower their markup based on market pressures, or they'll choose to lower their markup when it's reviewed and recalculated."*
2. *Any increase in profit following an input cost increase is likely to be short-lived. "There are too many pressures on contractors to lower their prices for various reasons… We'll guess this isn't the first time over the past 40 years that equipment prices have increased because of regulatory changes rather than inflationary or commodity price increases. Construction today is not a more profitable industry than it was decades ago."*
3. *Contractor profit margins and markups are typically reevaluated every three to six months; this limits the timeframe in which higher-than-sustainable profits are likely to persist.*

The consultant's responses provide real-world evidence indicating that HVAC contractors aim to maintain fixed percent markups, but market pressures force them to reevaluate and adjust markups over time to stay competitive. This empirical phenomenon reinforces the underlying theory and assumptions inherent in the incremental markup approach used in DOE's post-standard price projections. DOE concludes that the combined evidence of changing percent gross margins across industries with cost changes and the support of the industry consultant justify the use of the incremental markup approach.

6B.4 CONSULTANT INTERVIEW REPORT

In this section, the original responses from consultant regarding markup practice in construction industry is presented as a supplementary material supporting the use of incremental markup when estimating the consumer product price of more efficient products.

To: Lawrence Berkeley National Laboratory
From: Michael Stone, Construction Programs & Results, Inc.
Date: January 26, 2015
Re: Supplementary questions on contractor markups

After a new energy efficiency standard is in place, the equipment prices generally go up as less efficient (cheaper) ones are eliminated on the market by new standard. The questions below are intended to help us understand the impact of increased equipment prices on contractors' markup practices and profitability. That is, how contractors react to this change in equipment price while the other costs remain constant.

(1) Assuming the equipment price increases while the other costs remain constant (no change in labor, material and operating costs), are contractors still able to keep the same markup over time as before?

Michael Stone (Michael): *Yes and no. The contractors will attempt to use the same markup over time, but, assuming no increase in other costs, they'll eventually either have to lower their markup based on market pressures, or they'll choose to lower their markup when it's reviewed and recalculated.*

Keep in mind the numbers and our answer assume a "pure" company; one that currently only installs the lower efficiency units and that in the future will only install the higher efficiency units. They don't perform any other service work or install any other equipment. Those companies don't exist in real life. So it's most likely that on individual sales, if under pressure, the contractor might choose to reduce their markup because they recognize the equipment price increase without other related cost increases. The markup change will happen when the company's finances are reviewed, and the equipment cost increase will be only one factor in the adjustment.

(2) Keeping a fixed markup when the equipment price goes up implies that the contractor's profitability would increase, assuming no other cost changes. Is this increase in profitability viable over time?

Michael: *Probably not. There are too many pressures on contractors to lower their prices for various reasons. Unless building owners suddenly have more money to spend and consider the work on their building valuable enough to pay what it's worth, profitability will stay the same.*

We'll guess this isn't the first time over the past 40 years that equipment prices have increased because of regulatory changes rather than inflationary or commodity price increases. Construction today is not a more profitable industry than it was decades ago.

(3) If contractors would have to adjust their markup in this situation due to competition, how long does it take for them to revisit their markup values and adjust the firm's profitability to a competitive level?

Michael: *Generally speaking, 3-6 months.*

(4) For commercial contractors, is the market as competitive as for residential contractors? Is there a significant difference in their ability to maintain a fixed markup between commercial and residential contractors? If so, please elaborate the differences.

Michael: *There are so many variations in how commercial contractors operate, and the market is considerably different than residential. But it is as competitive.*
Many of them get jobs because of their connections. They do a lot of marketing and schmoozing, promoting themselves to buyers. This enables them to get jobs easier. If they have long-time relationships with general contractors who are primarily concerned with getting a job well-built with few problems, they can have an easier time maintaining a fixed markup. If they have long-time relationships with general contractors who are more concerned about getting the job built at the lowest possible price, they might choose to cut their price to get jobs.
Others get jobs by competing to be the lowest price. If they have relationships and can influence the bid process, they might have a bid that's written with them in mind, making it easier for them to be low bid and still maintain a reasonable markup on the job. Other contractors just shoot to be the lowest bid and have a tough time being profitable (ie, no, they don't maintain a fixed markup).

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CHAPTER 7. ENERGY USE ANALYSIS

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CHAPTER 7. ENERGY USE ANALYSIS

7.1 INTRODUCTION

The purpose of the energy use analysis is to determine the annual energy consumption of residential boilers in use in the United States and to assess the energy savings potential of increases in annual fuel utilization efficiency (AFUE) and standby mode and off mode efficiency. In contrast to the U.S. Department of Energy (DOE) test procedure, which uses typical operating conditions in a laboratory setting, the energy use analysis seeks to estimate the range of energy consumption of products in the field. DOE estimated the annual energy consumption of boilers at specified energy efficiency levels across a range of climate zones, building characteristics, and heating applications.

To calculate the energy consumed by residential boilers, DOE considered the energy use associated with providing space and domestic water heating in residential and commercial buildings.[a] DOE did not include within the energy use estimates energy used for snow melt systems, pool or spa heating, or steam or hot water production for industrial or commercial processes.[b] The energy use analysis provides estimates of the distribution of annual energy consumption for boilers at the efficiency standard levels considered.

DOE developed energy consumption estimates for the key product classes listed in Table 7.1.1. The boilers analyzed utilize gas or oil fuel for heating water or steam and the associated electric energy to power a water pump, a draft inducer, an ignitor, and other auxiliary equipment.

Table 7.1.1 Residential Boiler Product Classes Analyzed for AFUE and Standby Mode and Off Mode Energy Conservation Standards

Gas-Fired Hot Water Boilers
Gas-Fired Steam Boilers
Oil-Fired Hot Water Boilers
Oil-Fired Steam Boilers
Electric Hot Water Boilers (standby mode and off mode only)
Electric Steam Boilers (standby mode and off mode only)

DOE estimated the energy consumption of boilers in housing units and commercial buildings by developing a building sample for each of the four product classes listed in Table 7.1.1 based on the Energy Information Administration's (EIA) 2009 Residential Energy Consumption Survey (RECS 2009) and EIA's 2003 Commercial Building Energy Consumption

[a] Space heating applications for residential boilers include radiant heating (in-floor, radiant panels, radiators, baseboard) and forced air using fan coils or central air handlers. Domestic water heating applications for residential boilers include indirect water heating, combination products, and tankless coil.
[b] Examples of industrial and/or commercial processes include car washes, steam for dry cleaning, restaurant water heating, and manufacturing.

Survey (CBECS 2003).[1,2] These are the latest available surveys for residential and commercial buildings.[c] This sample is further described in section 7.2.

DOE used RECS 2009- or CBECS 2003-reported heating energy consumption (based on the existing heating system) to calculate the space heating load of each household or building. The heating load represents the amount of heating required to keep a housing unit comfortable throughout an average year. In households or buildings in which DOE identified that the boiler also serves domestic hot water heating needs, DOE used the RECS 2009 or CBECS 2003 reported water heating energy (based on the existing heating system) to calculate the water heating load of each household or building.

DOE assigned the energy efficiency of existing systems based on the design of the distribution systems (heating application), a historical distribution of energy efficiencies for boilers, and data indicative of the age of the existing boiler. In addition, DOE made adjustments based on historical weather data, average return water temperature, projections of shell efficiency and building square footage, automatic means for adjusting water temperature, installation location, and for homes that had secondary heating equipment that used the same fuel as the boiler. To complete the analysis, DOE calculated the energy consumption of alternative (more energy-efficient) products, if they replaced existing systems in each housing unit or building.

7.2 BUILDING SAMPLE

DOE's calculation of the annual energy use of residential boilers relied on data from RECS 2009 and CBECS 2003.[1,2] RECS 2009 included energy-related data from 12,083 housing units that represent almost 113.6 million households. CBECS 2003 included energy-related data from 5,215 buildings representing 4.9 million buildings.

The subset RECS 2009 or CBECS 2003 records used in the analysis met all of the following criteria:

- used a boiler as the main or secondary source of heat;
- used a heating fuel that is natural gas, liquefied petroleum gas (LPG), electricity, or fuel oil; and
- had a heating energy consumption greater than zero.

DOE divided the boiler subset into further subsets designed to include households that use one of the residential boiler product classes (Table 7.2.1 and Table 7.2.2 for residential applications and Table 7.2.3 and Table 7.2.4 for commercial applications). The new construction sample includes only buildings built after 1990, which DOE believes would have more similar building characteristics to the new construction buildings in 2021 (*e.g.* building insulation, regional distribution of the buildings, *etc*.). Because RECS 2009 does not report the heating

[c] EIA is currently working on the 2015 version of RECS, which is not expected to be available until 2017. Additionally, CBECS 2012 is currently in development and not all of the necessary data was available in time for this rulemaking. The full CBECS 2012 dataset is expected to be available in February 2016.

medium (hot water or steam), DOE used samples for hot water and steam boiler product classes that include all houses that might use either hot water or steam. For steam boilers in particular, this results in a sample size that represents many more houses than actually use steam boilers.

The RECS 2009 and CBECS 2003 weighting indicates how frequently each household or commercial building configuration occurs in the general population in 2009 and 2003, respectively. DOE adjusted EIA's weightings for each RECS 2009 and CBECS 2003 household to match projected shipments in 2021 from DOE's shipments analysis (see chapter 9) as well as accounting for the fraction of boilers that produce steam compared to hot water, buildings with multiple boilers, and 2008-2012 average shipments by state. Appendix 7A presents the variables included and their definitions, as well as further information about the derivation of the boiler samples, the adjustments to the boiler population weights, and sampling fractions for each of the four market segments (residential replacement/new construction and commercial replacement/new construction).[d]

To sample between the residential and commercial samples, DOE used RECS 2009 and CBECS 2003 data to estimate that 8 percent of gas-fired, 5 percent of oil-fired, and 32 percent of electric residential boiler shipments will be installed in commercial buildings in 2021. To sample between the new construction and replacement markets, DOE used residential boiler shipment forecasts for the year 2021 to estimate that 9 percent of gas-fired hot water boilers, 18 percent of electric hot water boilers, 4 percent of oil-fired hot water boilers, and 0 percent of gas-fired, oil-fired, and electric steam boilers are installed in new construction in 2021. See chapter 9 for further details.

[d] For gas-fired hot water boilers, residential and commercial replacement sample includes both replacements of existing gas-fired hot water boilers and new owners, which are existing homes that do not have an existing gas-fired hot water boilers. New owners account for 31 percent of the replacement sample (see chapter 9 for more details).

Table 7.2.1 Selection of RECS 2009 Records for Residential Boilers (Replacements)

Product Class	Algorithm	No. of Records	RECS 2009	DOE 2021
			Number of Houses ***million****	**Number of Boiler Shipments** ***thousands***
Gas-Fired Hot Water Boilers	Heating Equipment = Gas Boiler* Heated Square footage <20,000 sq ft	685	6.42	224.65
Gas-Fired Steam Boilers	Heating Equipment = Gas Boiler House Built = before 1970 Heated Square footage <20,000 sq ft	497	4.82	28.49
Oil-Fired Hot Water Boilers	Heating Equipment = Oil Boiler Heated Square footage <20,000 sq ft	437	3.57	77.17
Oil-Fired Steam Boilers	Heating Equipment = Oil Boiler House Built = before 1970 Heated Square footage <20,000 sq ft	325	2.75	8.23
Electric Hot Water Boiler	Heating Equipment = Electric Boiler Heated Square footage <20,000 sq ft	41	0.41	11.36
Electric Steam Boiler	Heating Equipment = Electric Boiler House Built = before 1970 Heated Square footage <20,000 sq ft	26	0.27	2.01

* Natural gas or LPG boiler.
** Note that the total of these records and corresponding number of houses is not equivalent to DOE's residential boiler sample weights, which represent the number of boiler shipments in 2021.

Table 7.2.2 Selection of RECS 2009 Records for Residential Boilers (New Construction)

Product Class	Algorithm	No. of Records	RECS 2009	DOE 2021
			Number of Houses ***million****	**Number of Boiler Shipments** ***thousands***
Gas-Fired Hot Water Boilers	Heating Equipment = Gas Boiler Heated Square footage <20,000 sq ft House Age ≥ 1990	54	0.53	17.94
Gas-Fired Steam Boilers	NA*	0	0.00	0.00
Oil-Fired Hot Water Boilers	Heating Equipment = Oil Boiler Heated Square footage <20,000 sq ft House Age ≥ 1990	46	0.29	2.57
Oil-Fired Steam Boilers	NA*	0	0.00	0.00
Electric Hot Water Boiler	Heating Equipment = Electric Boiler Heated Square footage <20,000 sq ft House Age >= 1990	5	0.06	0.97
Electric Steam Boiler	NA*	0	0.00	0.00

* DOE assumed that there are no steam boilers in the new construction market.
** Note that the total of these records and corresponding number of houses is not equivalent to DOE's residential boiler sample weights, which represents number of boiler shipments in 2021.

Table 7.2.3 Selection of CBECS 2003 Records for Residential Boilers (Replacements)

Product Class	Algorithm	No. of Records	RECS 2009	DOE 2021
			Number of Houses ***million****	**Number of Boiler Shipments** ***thousands***
Gas-Fired Hot Water Boilers	Heating Equipment = Gas Boiler* Heated Square footage <20,000 sq ft	218	0.22	15.83
Gas-Fired Steam Boilers	Heating Equipment = Gas Boiler Building Built = before 1970 Heated Square footage <20,000 sq ft	157	0.17	2.33
Oil-Fired Hot Water Boilers	Heating Equipment = Oil Boiler Heated Square footage <20,000 sq ft	69	0.10	4.27
Oil-Fired Steam Boilers	Heating Equipment = Oil Boiler Building Built = before 1970 Heated Square footage <20,000 sq ft	54	0.08	0.45
Electric Hot Water Boiler	Heating Equipment = Electric Boiler Heated Square footage <20,000 sq ft	100	0.09	3.47
Electric Steam Boiler	Heating Equipment = Electric Boiler Building Built = before 1970 Heated Square footage <20,000 sq ft	61	0.06	0.84

* Natural gas or LPG boiler.

** Note that the total of these records and corresponding number of houses is not equivalent DOE's residential boiler sample weights, which represents number of boiler shipments in 2021.

Table 7.2.4 Selection of CBECS 2003 Records for Residential Boilers (New Construction)

Product Class	Algorithm	No. of Records	RECS 2009	DOE 2021
			Number of Houses *million***	Number of Boiler Shipments *thousands*
Gas-Fired Hot Water Boilers	Heating Equipment = Gas Boiler Heated Square footage <20,000 sq ft Building Age ≥ 1990	21	0.02	5.22
Gas-Fired Steam Boilers	NA*	0	0.00	0.00
Oil-Fired Hot Water Boilers	Heating Equipment = Oil Boiler Heated Square footage <20,000 sq ft Building Age ≥ 1990	10	0.02	0.53
Oil-Fired Steam Boilers	NA*	0	0.00	0.00
Electric Hot Water Boiler	Heating Equipment = Electric Boiler Heated Square footage <20,000 sq ft Building Age ≥ 1990	15	0.01	2.24
Electric Steam Boiler	NA*	0	0.00	0.00

* DOE assumed that there are no steam boilers in the new construction market.
** Note that the total of these records and corresponding number of houses is not equivalent to DOE's residential boiler sample weights, which represents number of boiler shipments in 2021.

7.3 RESIDENTIAL BOILER ENERGY CONSUMPTION

To calculate the energy use of residential boilers in each product class, DOE determined the energy consumption associated with space heating, water heating, and any auxiliary electrical use during periods of space and/or water heating. For the space heating energy consumption determination, DOE estimated the input capacity and burner operating hours of the existing boiler(s) using building heating loads and boiler characteristics. For the domestic water heating energy consumption determination, DOE identified the building water heating load and the AFUE of the existing boiler.

The electrical consumption was determined using the burner operating hours associated with space and water heating and individual electrical measurements of all electrical components. Standby electrical consumption was also considered in the electrical energy use. The sum of the space heating, water heating and electrical energy consumptions represents the estimated annual energy use of a sampled boiler. Additional details used for determining the total energy use can be found in the following sections.

The calculation used for determining the total energy use is as follows:

$$Energy\ Use_{Total} = FuelUse_{SH} + FuelUse_{WH} + ElecUse_{Total}$$

Eq. 7.1

Where:

$FuelUse_{SH}$ = total fuel consumption as a result of space heating loads,
$FuelUse_{WH}$ = total fuel consumption as a result of water heating loads, and
$ElecUse_{Total}$ = electrical consumption of all electrical components.

7.3.1 Space Heating Fuel Consumption

The annual fuel consumption (*FuelUse*) for each single-stage boiler is determined using the following formula:[e,f]

$$FuelUse_{SH} = BOH_{SH} \times Q_{IN}$$

Eq. 7.2

Where:

BOH_{SH} = space heating burner operating hours (hr/yr), and
Q_{IN} = input capacity of existing boiler (kBtu/hr).

DOE derived the BOH_{SH} from the annual building heating load served by a single boiler. The building heating load was determined from annual fuel consumption for heating reported in RECS 2009 and CBECS 2003 based on the AFUE of the existing boiler (see 7.3.1.1). DOE derived Q_{IN} by accounting for the adjusted peak heating load of the household or building, the AFUE of the existing boiler, and a shipments adjustment factor (see 7.3.1.2). DOE assumed that Q_{IN} is the same for all efficiency levels (regardless of the output capacity).

7.3.1.1 Determination of Space Heating Burner Operating Hours (BOH_{SH})

DOE calculated space heating burner operating hours for a single-stage boiler as:

$$BOH_{SH} = \frac{BHL_{Boiler}}{Q_{Useful}}$$

Eq. 7.3

Where:

Q_{Useful} = total useful energy output of the boiler, including useful heat from auxiliary electrical components (kBtu/hr), and
BHL_{Boiler} = annual building heating load served by a single boiler (kBtu/yr).

---

[e] This formula assumes that the product does not have a pilot light, which is true for all residential boilers sold after September 2012.
[f] For two-stage and modulating products this formula includes parameters for the operation at full, modulating, and reduced load.

The total useful energy output (Q_{Useful}) includes the heating capacity of the boiler as well as useful heat from auxiliary electrical components (such as the electronic ignition, water pump, and power to the burner) during the periods of space heating and during standby. The heating capacity is adjusted to reflect the variation in AFUE in different hydronic space heating applications by associating a specific space heating application with each sampled household or building. This field adjusted AFUE ($AFUE_{adj}$) includes adjustments depending on the return water temperature (RWT), automatic means for adjusting water temperature, and jacket losses. See section 7.3.1.3 and appendix 7B for more details.

The annual building-heating load (BHL_{Boiler}) is the total amount of heat output from the boiler that the house or building needs during the heating season.[g] DOE determined BHL_{Boiler} for each sampled housing unit or building, based on the efficiency of the assigned existing boiler, using the following calculations:

$$BHL_{Boiler} = \frac{\left(Q_{YR} \times AFUE_{ex,adj}\right) \times Adj_{Factor(s)}}{BoilerCount} \times NumberofUnitsServed$$

Eq. 7.4

Where:

Q_{YR} = annual fuel consumption for heating based on RECS 2009 or CBECS 2003, kBtu/yr,
$AFUE_{ex,adj}$ = AFUE of the existing boiler ($AFUE_{ex}$) adjusted for return water temperature (RWT),[h] automatic means, and jacket losses (see section 7.3.1.3),
$Adj_{Factor(s)}$ = adjustment factors (discussed below),
BoilerCount = number of boilers used to fulfill the building heating load, and
NumberofUnitsServed = number of housing units served by a single boiler.

Both RECS 2009 and CBECS 2003 report space heating energy use (Q_{YR}) for each of the sampled buildings. Table 7.3.1 shows the original RECS 2009 and CBECS 2003 heating energy use.

[g] BHL_{Boiler} is the load served by a single boiler. DOE assumed that some of the building structures would be served by multiple residentially-sized boilers based on RECS data, heating load of the building (if it exceeds 300 Btu/h), and/or the application (such as multi-family and commercial applications).
[h] Return water temperature represents the average annual return water temperature for the different space heating applications.

Table 7.3.1 Range of Original Heating Energy Use Based on RECS 2009 and CBECS 2003 Data, MMBtu/year

Product Class	Min	Max	Average	Percentiles				
				5%	25%	50%	75%	95%
Gas-Fired Hot Water Boilers	0.1	4725.4	95.9	22.6	55.3	72.9	104.1	200.2
Gas-Fired Steam Boilers	0.5	1291.3	97.6	28.6	58.5	78.2	112.6	200.8
Oil-Fired Hot Water Boilers	0.0	2219.0	99.1	31.2	51.4	72.3	111.4	187.6
Oil-Fired Steam Boilers	0.0	2219.0	105.7	30.6	51.0	70.8	115.4	211.6
Electric Hot Water Boiler	0.0	364.3	15.5	3.1	7.7	12.1	18.9	39.5
Electric Steam Boiler	0.0	364.3	17.1	2.3	7.7	11.4	21.9	39.5

DOE adjusted the BHL to reflect the expectation that the buildings in 2021 will have a somewhat different BHL than the buildings in the RECS 2009 and CBECS 2003 boiler samples. The adjustment involves multiplying the calculated BHL for each RECS 2009 or CBECS 2003 building by the building shell efficiency index[i] based on information from the National Energy Modeling System (NEMS) simulation performed for EIA's *Annual Energy Outlook 2015* (*AEO 2015)*.[3] This factor differs for residential and commercial buildings as well as new construction and replacement buildings. The factor applied in the analysis for residential buildings is 0.91 for replacements and new construction, while for commercial buildings it ranged from 0.72 to 0.95 for replacements (depending on building type) and ranged from 0.34 to 0.85 for new construction. This means that buildings on average will have lower space heating load compared to residential buildings in 2009 or commercial buildings in 2003.

DOE also adjusted the calculated BHL_{BOILER} using heating degree days reported in RECS 2009 and CBECS 2003 for each building and National Oceanic and Atmospheric Administration (NOAA) data by region to reflect historical average climate conditions:[4]

$$Adj_{Factor_{average_{climate}}} = \frac{HDD_{10_{yr_{avg}}}}{HDD_{bldg_{2009}}}$$

Eq. 7.5

Where:

HDD_{bldg_2009} = HDD in 2009 for the specific region where the housing unit is located, and
$HDD_{10_yr_avg}$ = 10-year average HDD (2005–2014) based on National Oceanic and Atmospheric Administration (NOAA) data for the specific region where the housing unit is located.[j]

[i] The building shell efficiency index sets the heating load value at 1.00 for an average home in 2009 (by type) in each census division. The values listed in appendix 7B represent the change in heating load based on the difference in physical size and shell attributes for homes in the future (which takes into account physical size difference and efficiency gains from better insulation and windows).
[j] The last 10-year average is used to normalize the HDD values, which is similar to what is done in *AEO 2015*.

The historical average climate conditions adjustment factor for residential buildings ranges from 0.15 to 1.02 and was on average 0.96 for the residential boiler building sample (*i.e.*, 2009 was in general colder than the 10-year average). The historical average climate conditions adjustment factor for commercial buildings ranged from 0.90 to 1.07 and was on average 0.94 for the residential boiler building sample (*i.e.*, 2003 was in general colder than the 10-year average).

DOE also accounted for future climate trends based on *AEO 2015* HDD projections, which show a decline in HDD, leading to lower projected BHL_{BOILER} in 2021 relative to the non-climate-trend-adjusted BHL_{BOILER} values.

DOE determined that some of the sampled buildings used multiple heating products with the same fuel as the boiler(s), such as a central furnace, wall furnace, room heater, stove, or fireplace. Therefore, DOE adjusted the calculated BHL when necessary to reflect the use of secondary heating equipment using the same fuel as the boiler(s). The adjustment factors are calculated using reported survey information from both RECS 2009 and CBECS 2003 regarding the fraction of heating that was met by different heating equipment.

Table 7.3.2 shows the results for the range in annual building heating load among sample households and buildings for each boiler product class. These results are smaller than those reported in RECS 2009 or CBECS 2003, primarily due to projected improvements in building shell efficiency and projected lower heating loads due to decreased heating degree days.

Table 7.3.2 Range of Annual Heating Load in 2021 for Each Residential Boiler Product Class, MMBtu/year

Product Class	Min	Max	Average	Percentiles				
				5%	25%	50%	75%	95%
Gas-Fired Hot Water Boilers	0.0	2857.0	60.8	14.8	34.0	46.3	66.6	124.9
Gas-Fired Steam Boilers	0.3	914.8	60.0	16.0	35.5	48.9	68.7	119.6
Oil-Fired Hot Water Boilers	0.0	1724.1	66.9	19.5	34.7	48.6	74.7	126.0
Oil-Fired Steam Boilers	0.0	1656.4	68.8	18.8	32.9	45.1	74.8	133.0
Electric Hot Water Boiler	0.0	331.1	8.4	1.2	2.7	7.7	9.9	20.3
Electric Steam Boiler	0.0	331.1	10.0	1.8	5.6	8.4	13.1	20.3

Once the heating load of each sample housing unit or building is known, it is possible to estimate what the burner operating hours and energy consumption of the baseline product as well as more-efficient products used in the analysis. Table 7.3.3 shows the results for the baseline heating residential boiler operating hours among sample households and buildings.

Table 7.3.3 Range of Baseline Boiler Heating Annual Operating Hours for Each Residential Boiler Product Class, hours

Product Class	Min	Max	Average	Percentiles				
				5%	25%	50%	75%	95%
Gas-Fired Hot Water Boilers	0	8760	683	199	385	555	827	1428
Gas-Fired Steam Boilers	2	5773	598	165	348	495	733	1384
Oil-Fired Hot Water Boilers	0	8760	589	161	331	485	680	1313
Oil-Fired Steam Boilers	0	7834	547	140	290	429	619	1285
Electric Hot Water Boiler	0	1988	100	11	28	88	154	213
Electric Steam Boiler	0	1988	102	20	36	96	146	215

Table 7.3.4 shows the results for the baseline heating residential boiler standby operating hours among sample households and buildings.

Table 7.3.4 Range of Baseline Boiler Standby Annual Operating Hours for Each Residential Boiler Product Class, hours

Product Class	Min	Max	Average	Percentiles				
				5%	25%	50%	75%	95%
Gas-Fired Hot Water Boilers	833	8760	7254	4799	6773	7675	8105	8451
Gas-Fired Steam Boilers	1969	8758	7569	5169	7005	8147	8369	8544
Oil-Fired Hot Water Boilers	2796	8760	7805	5457	7790	8154	8362	8577
Oil-Fired Steam Boilers	3202	8760	7714	5293	7429	8234	8423	8598
Electric Hot Water Boiler	1949	8758	8171	5716	8442	8643	8698	8748
Electric Steam Boiler	1949	8758	8015	5621	8484	8661	8724	8748

7.3.1.2 Determination of Product Sizing (Q_{IN})

To support the calculation of space heating energy use, DOE had to establish a methodology for deriving the boiler input capacity (Q_{IN}) of each of the sampled buildings. DOE assumed that Q_{IN} is the same for the existing boiler and for the new boiler at all efficiency levels, regardless of the output capacity. The determination of Q_{IN} of the sampled household or building accounts for the adjusted peak heating load of the building, the AFUE of the existing boiler ($AFUE_{ex}$), and a shipments adjustment factor using the following equation:

$$Q_{IN} = \frac{AdjustedHeatLoad}{AFUE_{ex}} \times ShipmentsAdjustmentFactor$$

Eq. 7.6

Where:

AdjustedHeatLoad = estimated building peak heat loss adjusted for building characteristics (see appendix 7B), kBtu/h,
$AFUE_{ex}$ = AFUE of the existing boiler for each product class (see appendix 7B), and
ShipmentsAdjustmentFactor = varies from 1.45 to 1.87 by product class, based on average shipment weighted input capacity data from Burnham in 2014[5] (see appendix 7B).

The AFUE of the existing boiler ($AFUE_{ex}$) was determined by matching historical AFUE data to the reported age of the boiler in RECS 2009 or distribution of boiler age for CBECS 2003 buildings.[k] See appendix 7B for further details.

DOE calculated the adjusted peak heating load for each sample housing or building unit based on the applicable building characteristics and outdoor conditions derived from the RECS and CBECS data. The building characteristics include the building square footage, building vintage, foundation type, shell characteristics, number of floors, and outdoor design temperature. Appendix 7B presents further information about the boiler sizing methodology and values used.

7.3.1.3 Determination of Adjusted AFUE ($AFUE_{adj}$)

DOE adjusted the AFUE of the existing and new boiler to reflect the variation in efficiency in different hydronic space heating applications by associating a specific space heating application with each sampled household or building. The field adjusted AFUE of the existing ($AFUE_{ex,adj}$) and new boiler ($AFUE_{new,adj}$) was adjusted depending on the return water temperature (RWT), automatic means for adjusting water temperature, and jacket losses, using the following equation:

$$AFUE_{adj} = AFUE + Adj_{RWT_{AutomaticMeans}} + Adj_{JacketLosses} + Adj_{ExcessAir}$$

Eq. 7.7

Where:

$AFUE_{adj}$ = the adjusted AFUE of the boiler (either existing: $AFUE_{ex,adj}$, or new: $AFUE_{new,adj}$),
AFUE = the rated AFUE of the boiler (either existing: $AFUE_{ex,adj}$ or of the new boiler to be installed: $AFUE_{new,adj}$),
$Adj_{RWT_AutomaticMeans}$= adjustment factors for RWT and automatic means (see Table 7.3.5 and Table 7.3.6),
$Adj_{JacketLosses}$ = adjustment factor for jacket losses (see appendix 7B), and
$Adj_{ExcessAir}$ = adjustment factor field excess air (see appendix 7B).

Table 7.3.5 and Table 7.3.6 provide the adjustments to the AFUE of existing and new boilers based on different RWT application types and automatic means options. High RWT is applied to 100 percent of non-condensing boiler installations. For condensing boiler installations, low RWT is applied to 100 percent of new construction and new owners and to 10 percent of replacements. DOE assumed that all other condensing boiler installations would be in high RWT

[k] CBECS 2003 does not report the age of the equipment, so DOE created a uniform distribution (from 0 to 30 years, the upper limit being the age of the building) to estimate the age of the equipment.

applications. Appendix 7B provides additional details regarding the derivation of the adjustment values and methodology.

Table 7.3.5 AFUE Adjustment Based on RWT Application and Automatic Means Option for Single-Stage Boilers

Product Type	Average Return Water Temperature and Automatic Means Options			
	Low RWT (108°F)	Medium RWT (120°F)	High RWT w/ Automatic Means (158°F)*	High RWT w/o Automatic Means (160°F)*
Non-Condensing (single-stage)	-	As Reported	-0.53%	-0.56%
Condensing (single-stage)	1.90%	As Reported	-2.62%	-2.66%

* 160°F RTW is applied to all existing products, which are assumed to be without automatic means. 158°F RWT is applied to new products that must utilize automatic means.

Table 7.3.6 AFUE Adjustment Based on RWT Application and Automatic Means Option for Two-Stage/Modulating Boilers

	Low RWT (100°F)	Medium RWT (120°F)	High RWT (140°F)
Non-Condensing (2-stage/modulating)	-	As Reported	-0.28%
Condensing (2-stage/modulating)	3.15%	As Reported	-2.06%

DOE also accounted for jacket losses when the boiler is located in a non-conditioned space (*i.e.*, unconditioned basement or garage). For boilers located in conditioned spaces, DOE assumed that jacket losses contribute to space heating as useful heat. See appendix 8C for details about how DOE determined the installation location of boilers. Table 7.3.7 shows the jacket loss factors used for adjusting the AFUE of low- and high-mass boilers in conditioned and non-conditioned installation locations. The factors are only applied during the heating season. DOE assumed that 90 percent of condensing boilers and 10 percent of non-condensing boilers are low-mass. Appendix 7B provides details on how DOE derived and used the jacket loss factors.

Table 7.3.7 Adjustment to AFUE from Boiler Jacket Loss

Installation Location	Boiler Type	Jacket Loss Factor
Conditioned	Low Mass	0%
	High Mass	0%
Non-Conditioned	Low Mass*	0.25%
	High Mass**	1.2%

* Jacket loss factor (C_J) for boilers installed as isolated combustion systems from DOE's existing test procedure is 0.5 for finned-tube boilers and 2.4 for all other boilers. DOE assumed that the finned-tube value is similar to the value for low mass boilers. C_J is multiplied by the jacket loss (L_J), which DOE assumed is 0.5 percent.

The amount of excess air provided to the boiler during operation impacts the efficiency of the boiler. The current DOE test procedure requires the burners of gas-fired boilers to be adjusted to their maximum Btu input ratings at the normal pressure and to set the primary air shutters in accordance with the manufacturer's recommendation to give a good flame. Increased levels of excess air decrease the boiler efficiency. DOE accounted for differences in excess air between the test procedure and field conditions. DOE assumed that the increased excess air level in the field would be based on the assumed stack temperature and draft type, and would reduce AFUE between 0.0 percent and 1.6 percent. Appendix 7B provides details on how DOE derived this excess air adjustment.

7.3.2 Water Heating Energy Consumption

Residential boilers are often used to provide hot water in addition to space heating. The most common means of doing so are through an indirect water heater, tankless coil, or as an integrated part of the boiler.

RECS 2009 and CBECS 2003 do not provide any information about when a boiler is used to provide hot water. DOE determined that a fraction of the installations in buildings in RECS 2009 or CBECS 2003 that use the same fuel for both space and water heating also use boilers for water heating by matching the sample data to a 2015 Air-Conditioning, Heating, and Refrigeration Institute (AHRI) contractor survey.[6] DOE determined that water heating would be provided by a boiler when RECS 2009 or CBECS 2003 reports the use of storage tank water heating in 50 percent of gas-fired hot water boilers, 5 percent of gas-fired steam boilers, 40 percent of oil-fired hot water boilers, and 5 percent of oil-fired steam boilers. DOE determined that water heating would be provided by a boiler when RECS 2009 or CBECS 2003 reports the use of tankless water heating in all cases except for oil-fired steam boilers, in which case half of these installations would have water heating provided by the boiler.

To calculate the water heating energy use, DOE calculated the residential boiler fuel use for water heating for each efficiency level based on the following equation:

$$FuelUse_{WH} = \frac{WHL}{AFUE - Adj_{FactorWH}} \times \left(1 - \frac{WH_{loss}}{Q_{IN}}\right) + 8760 \times WH_{loss}$$

Eq. 7.8

Where:

WHL = water heating energy use based on RECS 2009 or CBECS 2003 (see Eq. 7.9), MMBtu/yr,
AFUE = AFUE of the selected efficiency level,
$Adj_{FactorWH}$ = adjustment factor to account for the difference between the AFUE and water heating efficiency (recovery efficiency) (see appendix 7B),
WH_{loss} = average water heater standby loss, kBtu/h (see appendix 7B),
Q_{IN} = as defined in Eq. 7.2, kBtu/h, and
8760 = total hours in a year.

DOE used the following equation to calculate the water heating load (WHL):

$$WHL = Q_{YR,HW} \times (AFUE_{ex} - Adj_{FactorWH})$$

Eq. 7.9

Where:

$Q_{YR,HW}$ = annual fuel consumption for water heating based on RECS 2009 or CBECS 2003 (kBtu/yr),
$AFUE_{ex}$ = AFUE of the existing boiler (see appendix 7B), and
$Adj_{FactorWH}$ = as defined in Eq. 7.8.

Appendix 7B provides further details about the water heating methodology and results.

7.3.3 Electricity Consumption

The Department calculated boiler electricity consumption for the auxiliary electrical components including circulating pump, the boiler pump (condensing boilers only), the draft inducer (if present), and the ignitor. The circulating pump moves water through the house whenever the boiler burner is on (adjusted for delay times between burner and pump operation). When the boiler also serves the home's or building's water heating load, the circulating pump also operates in the non-heating season if there is a call for water heating. The boiler pump is internal to the boiler and circulates water through the boiler heat exchanger in condensing boilers. DOE assumed that half of condensing boiler installations use high efficiency circulating pumps and boiler pumps. In the case of modulating condensing boilers, to accommodate for lower firing rates, the inducer will provide lower combustion airflow to regulate the excess air in the combustion process. DOE assumed that modulating condensing boilers are equipped with inducer fans with permanent split capacitor (PSC) motors and two-stage controls.

DOE also accounted for the electricity consumption of auxiliary equipment such as a condensate pump and heat tape, which are sometimes installed with higher efficiency boilers. Additionally, DOE applied a methodology to account for the additional cooling load due to heat loss from the boiler and water heater as a result of water heating during the cooling season. DOE determined the type of water heater, water heating load, burner operating hours during the summer, and air conditioner (AC) type and efficiency for each household from RECS 2009 and CBECS 2003. DOE then calculated the heat loss from the boiler and the water heater and the subsequent increase in AC electricity use. Appendix 7B provides details.

For single-stage boilers, DOE calculated the electricity consumption as:[1]

$$ElecUse_{TOTAL} = (BOH_{SH} + BOH_{WH}) \times ElecPower + ElecUse_{Stby} + ElecUse_{AC}$$

Eq. 7.10

[1] For two-stage and modulating equipment, this formula includes parameters for the operation at full, modulating, and reduced load. See appendix 7B.

Where:

BOH_{SH} = as defined in Eq. 7.2,
BOH_{WH} = water heating burner operating hours (hr/yr) (see appendix 7B),
$ElecPower$ = power of multiple electrical components required during boiler operation, (kW) (refer to the test procedure variables detailed in appendix 7B),
$ElecUse_{Stby}$ = energy consumption during standby (kWh) (see Eq. 7.11), and
$ElecUse_{AC}$ = additional cooling energy consumption during non-heating season due to boiler operation for water heating loads (when applicable) (kWh) (see appendix 7B).

For the standby mode and off mode evaluation, the Department calculated the standby electricity consumption as:

$$ElecUse_{Stby} = StbyE \times (8760 - BOH_{SH} - BOH_{WH})$$

Eq. 7.11

Where:

$StbyE$ = power use during standby mode and off mode (kW),
8760 = hours in a year,
BOH_{SH} = as defined in Eq. 7.2, and
BOH_{WH} = as defined in Eq. 7.10.

DOE assumed that a fraction of electricity consumed by standby during the heating season is useful heat and resulted in a slight decrease in fuel used for space heating. DOE assumed that 25 percent of consumers turn off their boilers during the non-heating season.

Further details for calculating electricity consumption appear in appendix 7B.

7.4 SUMMARY OF ENERGY USE RESULTS

For AFUE standards, Table 7.4.1 presents the average annual energy use and the average energy savings for each considered energy efficiency level compared to the baseline energy efficiency for each residential boiler product class. The results reflect space heating and water heating energy use in both the residential and commercial samples.[m] See appendix 7B for disaggregated energy use values. The LCC and PBP analysis uses the results calculated for each sample building. Negative savings results indicate that energy use increases.

[m] Residential boilers used in commercial applications account for 8 percent of gas-fired, 5 percent of oil-fired, and 32 percent of electric residential boiler shipments in 2021. See chapter 9.

Table 7.4.1 Average Annual Energy Consumption and Savings for Residential Boilers for AFUE Standard

EL	Design Option	Annual Fuel Use		Annual Electricity Use	
		Total *MMBtu/yr*	Savings *MMBtu/yr*	Total *kWh/yr*	Savings *kWh/yr*
Gas-fired Hot Water Boiler					
0	82% AFUE - Baseline	85.9	-	197	-
1	83% AFUE – Increased HX Area	84.8	1.0	195	2
2	84% AFUE – Increased HX Area	83.8	2.1	193	4
3	85% AFUE – Increased HX Area	82.6	3.3	214	-17
4	90% AFUE – Condensing Baseline	75.3	10.5	329	-132
5	92% AFUE – Increased HX Area	73.8	12.1	323	-126
6	96% AFUE – Max Tech	70.8	15.1	312	-115
Gas-fired Steam Boiler					
0	80% AFUE - Baseline	80.3	-	88	-
1	82% AFUE – Increased HX Area	78.3	2.1	91	-3
2	83% AFUE – Max Tech	77.2	3.1	96	-8
Oil-fired Hot Water Boiler					
0	84% AFUE - Baseline	80.3	-	230	-
1	85% AFUE – Increased HX Area	79.3	1.0	234	-4
2	86% AFUE – Increased HX Area	78.0	2.3	231	-1
3	91% AFUE – Max Tech	73.0	7.3	265	-35
Oil-fired Steam Boiler					
0	82% AFUE - Baseline	78.3	-	181	-
1	84% AFUE – Increased HX Area	76.3	1.9	178	3
2	85% AFUE – Increased HX Area	75.4	2.9	177	4
3	86% AFUE – Max Tech	74.1	4.1	175	6

Table 7.4.2 shows the average annual standby mode and off mode energy use for residential boilers and the average energy savings for each energy efficiency level, compared to the baseline.

Table 7.4.2 Average Annual Electricity Consumption and Savings for Residential Boilers for Standby Mode and Off Mode Standards

EL	Power *Watts*	Design Option	Annual Electricity Consumption for Standby	
			Total *kWh/yr*	Savings *kWh/yr*
Gas-fired Hot Water Boiler				
0	11.5	Baseline	83	-
1	10	Linear PS, Toroidal Xfmr	73	11
2	9.7	Switch Mode PS	70	13
3	9	SMPS, Toroidal Xfmr	65	7
Gas-fired Steam Boiler				
0	10.5	Baseline	79	-
1	9	Linear PS, Toroidal Xfmr	68	11
2	8.7	Switch Mode PS	66	14
3	8	SMPS, Toroidal Xfmr	61	8
Oil-fired Hot Water Boiler				
0	13.5	Baseline	105	-
1	12	Linear PS, Toroidal Xfmr	94	12
2	11.7	Switch Mode PS	91	14
3	11	SMPS, Toroidal Xfmr	86	8
Oil-fired Steam Boiler				
0	13.5	Baseline	104	-
1	12	Linear PS, Toroidal Xfmr	93	12
2	11.7	Switch Mode PS	90	14
3	11	SMPS, Toroidal Xfmr	85	8
Electric Hot Water Boiler				
0	10.5	Baseline	86	-
1	9	Linear PS, Toroidal Xfmr	74	12
2	8.7	Switch Mode PS	71	15
3	8	SMPS, Toroidal Xfmr	65	6
Electric Steam Boiler				
0	10.5	Baseline	84	-
1	9	Linear PS, Toroidal Xfmr	72	12
2	8.7	Switch Mode PS	70	14
3	8	SMPS, Toroidal Xfmr	64	6

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APPENDIX 7A. BUILDING VARIABLES

7A.1 INTRODUCTION

The U.S. Department of Energy (DOE) created a database containing a subset of the records and variables from DOE's Energy Information Administration (EIA)'s Residential Energy Consumption Survey (RECS) 2009 using Microsoft ACCESS.[1] DOE used this RECS 2009 subset in the life-cycle cost (LCC) analysis of the residential boiler rulemaking. This appendix explains the variable name abbreviations and provides definitions of the variable values.

For the entire RECS 2009 dataset, refer to www.eia.gov/consumption/residential/data/2009/index.cfm?view=microdata.

DOE created a database containing a subset of the records and variables from EIA's CBECS 2003.[2] DOE used this CBECS 2003 subset in the life-cycle cost (LCC) analysis of the residential boilers. This appendix explains the variable name abbreviations and provides definitions of the variable values. For the entire CBECS 2003 dataset, refer to www.eia.gov/consumption/commercial/data/2003/index.cfm?view=microdata.

7A.2 RECS 2009 SAMPLE DETERMINATION

RECS 2009 consists of three parts:

- Personal interviews with households for information about energy used, how it is used, energy-using appliances, structural features, energy efficiency measures, and demographic characteristics of the household.
- Telephone interviews with rental agents for households that have any of their energy use included in their rent. This information augments information collected from those households that may not be knowledgeable about the fuels used for space heating or water heating.
- Mail questionnaires sent to energy suppliers (after obtaining permission from households) to collect the actual billing data on energy consumption and expenditures.

The subset of RECS 2009 records used to study boilers met all of the following criteria:

- used a boiler as the main or secondary source of heat;
- used a heating fuel that is natural gas, liquefied petroleum gas (LPG), fuel oil, or electricity;
- heated only one housing unit; and
- had an energy consumption greater than zero.

The RECS 2009 weighting indicates how commonly each household configuration occurs in the general population. Table 7A.2.1 shows the RECS 2009 sample weights and

criteria for replacements[a] and Table 7A.2.2 shows the RECS sample weights and criteria for new construction. DOE made some adjustments to EIA's weightings for each RECS 2009 household in order to create boiler population weights in 2020. The boiler population weights are adjusted to account for:

1. Households sharing a boiler: RECS 2009-reported weight is decreased by the number of units sharing the boiler as follows a) single-family unit is assumed to share a boiler with one other unit; b) multi-family unit (2-4 units) is assumed to share a boiler with three other units; b) multi-family unit (5 or more units) is assumed to share a boiler with the number of reported units in the building;
2. Buildings with multiple boilers: RECS 2009-reported weight is increased by the number of boilers in a building for households listed in RECS 2009 with a primary and secondary boiler;
3. If the household/building has 10,000 square feet or more, then its sample weight was divided by half to take into account that half of these households/buildings use a commercial boiler;
4. Shipments by state: RECS 2009-reported weight is adjusted to match gas-fired and oil-fired boiler shipments data by state[3] (see Table 7A.2.3 through Table 7A.2.5); and
5. Shipments of hot water vs. steam boilers: RECS 2009 does not distinguish between hot water and steam boilers. The fraction of boilers that produce steam was assumed to be 11 percent for gas-fired boilers, 10 percent for oil-fired boilers, and 15 percent for electric boilers of the replacement sample (see appendix 9B).

[a] Replacements includes both replacements of existing boilers and new owners, which are existing homes that do not have an existing boiler. See chapter 9 for more details about these market segments.

Table 7A.2.1 Selection of RECS 2009 Records for Boilers (Replacements)

Product Class	Algorithm	No. of Records	RECS 2009	DOE 2021
			Number of Houses ***million*** **	**Number of Boiler Shipments** ***thousands***
Gas-Fired Hot Water Boilers	Heating Equipment = Gas Boiler* Heated Square footage <20,000 sq ft	685	6.42	224.65
Gas-Fired Steam Boilers	Heating Equipment = Gas Boiler House Built = before 1970 Heated Square footage <20,000 sq ft	497	4.82	28.49
Oil-Fired Hot Water Boilers	Heating Equipment = Oil Boiler Heated Square footage <20,000 sq ft	437	3.57	77.17
Oil-Fired Steam Boilers	Heating Equipment = Oil Boiler House Built = before 1970 Heated Square footage <20,000 sq ft	325	2.75	8.23
Electric Hot Water Boiler	Heating Equipment = Electric Boiler Heated Square footage <20,000 sq ft	41	0.41	11.36
Electric Steam Boiler	Heating Equipment = Electric Boiler House Built = before 1970 Heated Square footage <20,000 sq ft	26	0.27	2.01

* Natural gas or LPG boiler.

** Note that the total of these records and corresponding number of houses is not equivalent to DOE's residential boiler sample weights, which represent the number of boiler shipments in 2021.

Table 7A.2.2 Selection of RECS 2009 Records for Boilers (New Construction)

Product Class	Algorithm	No. of Records	RECS 2009	DOE 2021
			Number of Houses *million***	Number of Boiler Shipments *thousands*
Gas-Fired Hot Water Boilers	Heating Equipment = Gas Boiler Heated Square footage <20,000 sq ft House Age ≥ 1990	54	0.53	17.94
Gas-Fired Steam Boilers	NA*	0	0.00	0.00
Oil-Fired Hot Water Boilers	Heating Equipment = Oil Boiler Heated Square footage <20,000 sq ft House Age ≥ 1990	46	0.29	2.57
Oil-Fired Steam Boilers	NA*	0	0.00	0.00
Electric Hot Water Boiler	Heating Equipment = Electric Boiler Heated Square footage <20,000 sq ft House Age >= 1990	5	0.06	0.97
Electric Steam Boiler	NA*	0	0.00	0.00

* DOE assumed that there are no steam boilers in the new construction market.
** Note that the total of these records and corresponding number of houses is not equivalent to DOE's residential boiler sample weights, which represent the number of boiler shipments in 2021.

Table 7A.2.3 shows the average fraction of gas-fired and oil-fired boiler shipments by state from 2008-2012 based on AHRI shipment data.[3]

Table 7A.2.3 Fraction of Gas-fired and Oil-fired Boiler Shipments by State from 2008-2012 (AHRI Data)

Region ID	State	Fraction of Gas-fired Boiler Shipments	Fraction of Oil-fired Boiler Shipments
18	Alabama	0.01%	0.00%
28	Alaska	0.24%	0.34%
24	Arizona	0.09%	0.00%
20	Arkansas	0.01%	0.00%
26	California	0.60%	0.12%
22	Colorado	2.02%	0.08%
1	Connecticut	3.14%	11.43%
14	Delaware	0.16%	0.30%
14	District of Columbia	0.04%	0.00%
17	Florida	0.02%	0.01%
15	Georgia	0.02%	0.01%
29	Hawaii	0.00%	0.00%
23	Idaho	0.05%	0.00%
6	Illinois	4.42%	0.24%
7	Indiana	0.74%	0.16%

Region ID	State	Fraction of Gas-fired Boiler Shipments	Fraction of Oil-fired Boiler Shipments
10	Iowa	1.29%	0.08%
11	Kansas	0.06%	0.01%
18	Kentucky	0.10%	0.02%
20	Louisiana	0.14%	0.02%
1	Maine	0.77%	3.49%
14	Maryland	4.52%	7.37%
2	Massachusetts	9.78%	15.86%
8	Michigan	2.37%	0.14%
10	Minnesota	2.34%	0.18%
18	Mississippi	0.02%	0.00%
12	Missouri	0.32%	0.02%
23	Montana	0.47%	0.03%
11	Nebraska	0.08%	0.00%
25	Nevada	0.10%	0.02%
1	New Hampshire	5.82%	13.99%
4	New Jersey	12.07%	5.60%
25	New Mexico	0.37%	0.01%
3	New York	26.00%	24.35%
16	North Carolina	0.13%	0.18%
10	North Dakota	0.22%	0.05%
7	Ohio	2.03%	0.37%
20	Oklahoma	0.02%	0.00%
27	Oregon	0.29%	0.14%
5	Pennsylvania	9.89%	10.56%
1	Rhode Island	1.02%	1.32%
16	South Carolina	0.02%	0.03%
10	South Dakota	0.12%	0.01%
19	Tennessee	0.14%	0.01%
21	Texas	0.12%	0.05%
23	Utah	0.41%	0.02%
1	Vermont	0.33%	0.47%
13	Virginia	1.94%	1.34%
27	Washington	1.89%	1.33%
30	West Virginia	0.07%	0.03%
9	Wisconsin	3.17%	0.19%
23	Wyoming	0.03%	0.00%
	United States	100.00%	100.00%

Table 7A.2.4 shows the derivation of the adjustment factors used to determine the shipment-weighted building sample weights. The adjustment factors are derived as the ratio of the un-shipment weighted gas-fired or oil-fired boilers sample total to the average AHRI shipments by state. This factor is then multiplied to each household in the gas-fired or oil-fired boiler sample.

Table 7A.2.4 Shipment-Weighted Adjustment Factors for Gas-fired and Oil-fired Boiler Residential Sample based on AHRI Shipments by State

ID	State(s)	Gas-fired Hot Water and Steam Boilers			Oil-fired Hot Water and Steam Boilers		
		2008-2012 Shipments Fraction	HWGB and SGB Sample (Unweighted)	Shipment-Weighted Adjustment Factor	2008-2012 Shipments Fraction	HWOB and SOB Sample (Unweighted)	Shipment-Weighted Adjustment Factor
1	CT, ME, NH, RI, VT	11.07%	6.97%	1.588	30.70%	32.36%	0.949
2	Massachusetts	9.78%	10.42%	0.938	15.86%	13.52%	1.173
3	New York	26.00%	21.22%	1.225	24.35%	19.30%	1.262
4	New Jersey	12.07%	14.36%	0.841	5.60%	7.44%	0.752
5	Pennsylvania	9.89%	6.33%	1.563	10.56%	18.73%	0.564
6	Illinois	4.42%	7.76%	0.570	0.24%	0.00%	1.000
7	Indiana, Ohio	2.76%	4.34%	0.636	0.53%	0.50%	1.051
8	Michigan	2.37%	3.93%	0.604	0.14%	0.00%	1.000
9	Wisconsin	3.17%	2.93%	1.083	0.19%	0.00%	1.000
10	IA, MN, ND, SD	3.97%	4.33%	0.917	0.33%	1.59%	0.206
11	Kansas, Nebraska	0.14%	0.62%	0.231	0.01%	0.00%	1.000
12	Missouri	0.32%	0.59%	0.539	0.02%	0.00%	1.000
13	Virginia	1.94%	2.34%	0.829	1.34%	2.29%	0.586
14	DE, DC, MD	4.71%	2.06%	2.285	7.68%	3.84%	1.998
15	Georgia	0.02%	0.00%	1.000	0.01%	0.00%	1.000
16	NC, SC	0.15%	0.66%	0.227	0.21%	0.00%	1.000
17	Florida	0.02%	0.00%	1.000	0.01%	0.00%	1.000
18	AL, KY, MS	0.13%	0.34%	0.375	0.03%	0.00%	1.000
19	Tennessee	0.14%	0.00%	1.000	0.01%	0.00%	1.000
20	AR, LA, OK	0.17%	0.09%	1.865	0.02%	0.00%	1.000
21	Texas	0.12%	0.04%	2.673	0.05%	0.00%	1.000
22	Colorado	2.02%	6.31%	0.320	0.08%	0.00%	1.000
23	ID, MT, UT, WY	0.96%	0.00%	1.000	0.06%	0.00%	1.000
24	Arizona	0.09%	0.00%	1.000	0.00%	0.00%	1.000
25	NV, NM	0.47%	0.45%	1.056	0.03%	0.00%	1.000
26	California	0.60%	1.38%	0.430	0.12%	0.00%	1.000
27	OR, WA	2.18%	1.05%	2.075	1.48%	0.00%	1.000
28	Alaska	0.24%	1.48%	0.164	0.34%	0.00%	1.000
29	Hawaii	0.00%	0.00%	1.000	0.00%	0.00%	1.000
30	West Virginia	0.07%	0.00%	1.000	0.03%	0.44%	0.057

Table 7A.2.5 shows the final sample weight by geographical location.

Table 7A.2.5 Final Residential Sample Weights by RECS 2009 Regions

ID	State(s)	Gas-fired Hot Water Boilers		Gas-fired Steam Boilers	Oil-fired Hot Water Boilers		Oil-fired Steam Boilers
		Replace.	New Const.	Replace.	Replace.	New Const.	Replace.
1	CT, ME, NH, RI, VT	11.22%	14.49%	8.95%	31.66%	62.63%	23.97%
2	Massachusetts	9.90%	5.64%	10.27%	16.36%	24.97%	15.76%
3	New York	26.34%	20.81%	26.50%	25.11%	6.87%	28.48%
4	New Jersey	12.23%	27.83%	11.63%	5.77%	0.00%	6.85%
5	Pennsylvania	10.02%	0.00%	11.01%	10.89%	5.54%	12.00%
6	Illinois	4.48%	0.00%	5.49%	0.00%	0.00%	0.00%
7	Indiana, Ohio	2.80%	0.00%	3.66%	0.54%	0.00%	0.00%
8	Michigan	2.40%	0.56%	2.74%	0.00%	0.00%	0.00%
9	Wisconsin	3.21%	0.30%	3.81%	0.00%	0.00%	0.00%
10	IA, MN, ND, SD	4.03%	1.27%	4.09%	0.34%	0.00%	0.39%
11	Kansas, Nebraska	0.15%	0.00%	0.06%	0.00%	0.00%	0.00%
12	Missouri	0.32%	0.35%	0.32%	0.00%	0.00%	0.00%
13	Virginia	1.96%	2.42%	2.03%	1.38%	0.00%	1.86%
14	DE, DC, MD	4.78%	0.00%	6.24%	7.92%	0.00%	10.65%
15	Georgia	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
16	NC, SC	0.15%	0.00%	0.20%	0.00%	0.00%	0.00%
17	Florida	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
18	AL, KY, MS	0.13%	0.00%	0.17%	0.00%	0.00%	0.00%
19	Tennessee	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
20	AR, LA, OK	0.18%	0.00%	0.23%	0.00%	0.00%	0.00%
21	Texas	0.12%	0.00%	0.00%	0.00%	0.00%	0.00%
22	Colorado	2.04%	14.33%	0.53%	0.00%	0.00%	0.00%
23	ID, MT, UT, WY	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
24	Arizona	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
25	NV, NM	0.48%	2.76%	0.00%	0.00%	0.00%	0.00%
26	California	0.60%	1.25%	0.55%	0.00%	0.00%	0.00%
27	OR, WA	2.21%	7.26%	1.39%	0.00%	0.00%	0.00%
28	Alaska	0.25%	0.73%	0.15%	0.00%	0.00%	0.00%
29	Hawaii	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
30	West Virginia	0.00%	0.00%	0.00%	0.03%	0.00%	0.03%

7A.2.1 RECS 2009 Variables and Values

Table 7A.2.6 lists the variables use in the analysis.

Table 7A.2.6 List of RECS 2009 Variables Used for Boilers

Variable	Description
Location Variables	
REGIONC	Census Region
DIVISION	Census Division
REPORTABLE_DOMAIN	Reportable states and groups of states
HDD65	Heating degree days in 2009, base temperature 65F

Variable	Description
CDD65	Heating degree days in 2009, base temperature 65F
Household Characteristics Variables	
NWEIGHT	Final sample weight
DOEID	Unique identifier for each respondent
TYPEHUQ	Type of housing unit
YEARMADE	Year housing unit was built
BTUNGSPH	Natural Gas usage for space heating, in thousand BTU, 2009
BTULPSPH	LPG/Propane usage for space heating, in thousand BTU, 2009
BTUFOSPH	Fuel Oil usage for space heating, in thousand BTU, 2009
BTUELSPH	Electricity usage for space heating, in thousand BTU, 2009
BTUNGWTH	Natural Gas usage for water heating, in thousand BTU, 2009
BTULPWTH	LPG/Propane usage for water heating, in thousand BTU, 2009
BTUFOWTH	Fuel Oil usage for water heating, in thousand BTU, 2009
BTUELWTH	Electricity usage for water heating, in thousand BTU, 2009
EQUIPM	Type of main space heating equipment used
FUELHEAT	Main space heating fuel
HEATOTH	Main space heating equipment heats other homes, business, or farm
MAINTHT	Routine service or maintenance performed on main space heating equipment
EQUIPAGE	Age of main space heating equipment
RADFUEL	Fuel used by hot water system for secondary space heating
NUMH2ONOTNK	Number of tankless water heaters
NUMH2OHTRS	Number of storage water heaters
H2OTYPE1	Type of main water heater
FUELH2O	Fuel used by main water heater
WHEATOTH	Main water heater is used by more than one housing unit
WHEATSIZ	Main water heater size (if storage tank)
WHEATAGE	Main water heater age
EQMAMT	Portion of space heating provided by main space heating equipment (for homes with main and secondary heating only)
COOLTYPE	Type of air conditioning equipment used
CENACHP	Central air conditioner is a heat pump
NHSLDMEM	Number of household members
Seniors*	Number of household members age 65 or older
POVERTY100	Household income at or below 100% of poverty line
StationID*	ID number of weather station identified with household (see appendix 7C)
MONEYPY	2009 gross household income
STORIES	Number of stories in a single-family home
NUMAPTS	Number of apartment units in a 5+ unit apartment building
NAPTFLRS	Number of floors in an apartment (Number of levels in housing unit that is an apartment)
HIGHCEIL	High ceilings

Variable	Description
CATHCEIL	Cathedral ceilings
WALLTYPE	Major outside wall material
TOTSQFT	Total square footage (includes all attached garages, all basements, and finished/heated/cooled attics)
TOTSQFT_EN	Total square footage (includes heated/cooled garages, all basements, and finished/heated/cooled attics). Used for EIA data tables.
TOTHSQFT	Total heated square footage

* Not part of RECS 2009 variables.

7A.2.2 RECS 2009 Database Variable Response Codes

Table 7A.2.7 provides the response codes for all RECS 2009 variables used in the Heating Products samples.

Table 7A.2.7 Definitions of RECS 2009 Variables Used in Life-Cycle Cost Analysis

Variable	Response Codes
BTUELSPH	Thousand BTU
BTUFOSPH	Thousand BTU
BTULPSPH	Thousand BTU
BTUNGSPH	Thousand BTU
BTUNGWTH	Thousand BTU
BTULPWTH	Thousand BTU
BTUFOWTH	Thousand BTU
BTUELWTH	Thousand BTU
CATHCEIL	0 No 1 Yes -2 Not Applicable
CDD65	Cooling degree days in 2009, base temperature 65F
CENACHP	0 No 1 Yes -2 Not Applicable
COOLTYPE	1 Central system 2 Window/wall units 3 Both a central system and window/wall units -2 Not Applicable
DIVISION	1 New England Census Division (CT, MA, ME, NH, RI, VT) 2 Middle Atlantic Census Division (NJ, NY, PA) 3 East North Central Census Division (IL, IN, MI, OH, WI) 4 West North Central Census Division (IA, KS, MN, MO, ND, NE, SD) 5 South Atlantic Census Division (DC, DE, FL, GA, MD, NC, SC, VA, WV) 6 East South Central Census Division (AL, KY, MS, TN) 7 8

	9	West South Central Census Division (AR, LA, OK, TX)
	10	Mountain North Sub-Division (CO, ID, MT, UT, WY)
		Mountain South Sub-Division (AZ, NM, NV)
		Pacific Census Division (AK, CA, HI, OR, WA)
DOEID	00001 - 12083	Unique identifier for each respondent
	1	Almost all
	2	About three-fourths
	3	Closer to half
EQMAMT	-2	Not Applicable
	1	Less than 2 years old
	2	2 to 4 years old
	3	5 to 9 years old
	41	10 to 14 years old
	42	15 to 19 years old
	5	20 years or older
EQUIPAGE	-2	Not Applicable
	2	Steam or Hot Water System
	3	Central Warm-Air Furnace
	4	Heat Pump
	5	Built-In Electric Units
	6	Floor or Wall Pipeless Furnace
	7	Built-In Room Heater
	8	Heating Stove
	9	Fireplace
	10	Portable Electric Heaters
	11	Portable Kerosene Heaters
	12	Cooking Stove
	21	Other Equipment
EQUIPM	-2	Not Applicable
	1	Natural Gas
	2	Propane/LPG
	3	Fuel Oil
	4	Kerosene
	5	Electricity
	7	Wood
	8	Solar
	9	District Steam
	21	Other Fuel
FUELHEAT	-2	Not Applicable
	1	Natural Gas
	2	Propane/LPG
	3	Fuel Oil
	4	Kerosene
	5	Electricity
	7	Wood
	8	Solar
	21	Other Fuel
FUELH20	-2	Not Applicable

H2OTYPE1	1	Storage water heater
	2	Tankless water heater
	-2	Not Applicable
HDD65	Heating degree days in 2009, base temperature 65F	
HEATOTH	0	No
	1	Yes
	-2	Not Applicable
HIGHCEIL	0	No
	1	Yes
	-2	Not Applicable
MAINTHT	0	No
	1	Yes
	-2	Not Applicable
MONEYPY	1	Less than $2,500
	2	$2,500 to $4,999
	3	$5,000 to $7,499
	4	$7,500 to $9,999
	5	$10,000 to $14,999
	6	$15,000 to $19,999
	7	$20,000 to $24,999
	8	$25,000 to $29,999
	9	$30,000 to $34,999
	10	$35,000 to $39,999
	11	$40,000 to $44,999
	12	$45,000 to $49,999
	13	$50,000 to $54,999
	14	$55,000 to $59,999
	15	$60,000 to $64,999
	16	$65,000 to $69,999
	17	$70,000 to $74,999
	18	$75,000 to $79,999
	19	$80,000 to $84,999
	20	$85,000 to $89,999
	21	$90,000 to $94,999
	22	$95,000 to $99,999
	23	$100,000 to $119,999
	24	$120,000 or More
NHSLDMEM	0 - 15	Number of household members
NUMAPTS	5 - 995	Number of apartment units
	-2	Not Applicable
NUMH2ONOTNK	0 - 9	Number of Tankless Water Heaters
NUMH2OHTRS	0 - 9	Number of Storage Water Heaters
NWEIGHT	Final sample weight	
POVERTY100	0	No
	1	Yes
RADFUEL	1	Natural Gas
	2	Propane/LPG
	3	Fuel Oil

	4	Kerosene
	5	Electricity
	7	Wood
	8	Solar
	9	District Steam
	21	Other Fuel
	-2	Not Applicable
	1	Northeast Census Region
	2	Midwest Census Region
	3	South Census Region
REGIONC	4	West Census Region
		Connecticut, Maine, New Hampshire, Rhode Island, Vermont
	1	Massachusetts
	2	New York
	3	New Jersey
	4	Pennsylvania
	5	Illinois
	6	Indiana, Ohio
	7	Michigan
	8	Wisconsin
	9	Iowa, Minnesota, North Dakota, South Dakota
	10	Kansas, Nebraska
	11	Missouri
	12	Virginia
	13	Delaware, District of Columbia, Maryland, West
	14	Virginia
	15	Georgia
	16	North Carolina, South Carolina
	17	Florida
	18	Alabama, Kentucky, Mississippi
	19	Tennessee
	20	Arkansas, Louisiana, Oklahoma
	21	Texas
	22	Colorado
	23	Idaho, Montana, Utah, Wyoming
	24	Arizona
	25	Nevada, New Mexico
	26	California
REPORTABLE_DOMAIN	27	Alaska, Hawaii, Oregon, Washington
	0	No
Seniors	1	Yes
StationID	Three character identifier for weather station	
	10	One story
	20	Two stories
	31	Three stories
	32	Four or more stories
STORIES	40	Split-level

	50	Other type
	-2	Not Applicable
TOTHSQFT	Square Feet	
TOTSQFT	Square Feet	
TOTSQFT_EN	Square Feet	
TYPEHUQ	1	Mobile Home
	2	Single-Family Detached
	3	Single-Family Attached
	4	Apartment in Building with 2 - 4 Units
	5	Apartment in Building with 5+ Units
WALLTYPE	1	Brick
	2	Wood
	3	Siding (Aluminum, Vinyl, Steel)
	4	Stucco
	5	Composition (Shingle)
	6	Stone
	7	Concrete/Concrete Block
	8	Glass
	9	Other
WHEATOTH	0	No
	1	Yes
	-2	Not Applicable
WHEATSIZ	1	Small (30 gallons or less)
	2	Medium (31 to 49 gallons)
	3	Large (50 gallons or more)
	-2	Not Applicable
WHEATAGE	1	Less than 2 years old
	2	2 to 4 years old
	3	5 to 9 years old
	41	10 to 14 years old
	42	15 to 19 years old
	5	20 years or older
	-2	Not Applicable
YEARMADE	1600 - 2009	Year housing unit was built

* Not part of RECS 2009 variables.

7A.3 CBECS 2003 SAMPLE DETERMINATION

The subset of CBECS 2003 records used for residential boilers met all of the following criteria:

1) a boiler served as a source of heating;
2) building is not vacant; and
3) a boiler is used as the heating equipment at least a portion of the building.

Buildings were assigned to the sub-samples based on the amount of heating area per boiler, with similar reasoning as for residential boilers. CBECS 2003 provides the total heating

square footage and the fraction of heating by the boiler for each building record, but does not provide the number of boilers used by the building, so the entire heating square footage is used to determine the subsamples.

The CBECS 2003 weighting indicates how commonly each building configuration occurs in the general population. Table 7A.2.1 shows the CBECS 2003 sample weights and criteria for replacements and Table 7A.2.2 shows the CBECS 203 sample weights and criteria for new construction. DOE made some adjustments to EIA's weightings for each CBECS 2003 household in order to create boiler population weights in 2020. The boiler population weights are adjusted to account for:

1. Buildings with multiple boilers: CBECS 2003 reported weight is increased by the number of boilers in a building assuming that commercial buildings with over 5,000 sq. ft. have two or more boilers;
2. If the building has 10,000 square feet or more, then its sample weight was divided by half to take into account that half of these buildings use a commercial boiler;
3. Shipments by state: CBECS 2003-reported weight is adjusted to match data on the number of gas-fired and oil-fired boiler shipments by state[3] (see Table 7A.3.3 and Table 7A.3.4); and
4. Shipments of hot water vs. steam: CBECS 2003 does not distinguish between hot water and steam boilers. The fraction of steam boilers was assumed to be 13 percent for gas-fired boilers, 9 percent for oil-fired boilers, and 19 percent for electric boilers (see appendix 9B).

Table 7A.3.1 Selection of CBECS 2003 Records for Boilers (Replacements)

Product Class	Algorithm	No. of Records	RECS 2009	DOE 2021
			Number of Houses *million* **	**Number of Boiler Shipments *thousands***
Gas-Fired Hot Water Boilers	Heating Equipment = Gas Boiler* Heated Square footage <20,000 sq ft	218	0.22	15.83
Gas-Fired Steam Boilers	Heating Equipment = Gas Boiler Building Built = before 1970 Heated Square footage <20,000 sq ft	157	0.17	2.33
Oil-Fired Hot Water Boilers	Heating Equipment = Oil Boiler Heated Square footage <20,000 sq ft	69	0.10	4.27
Oil-Fired Steam Boilers	Heating Equipment = Oil Boiler Building Built = before 1970 Heated Square footage <20,000 sq ft	54	0.08	0.45
Electric Hot Water Boiler	Heating Equipment = Electric Boiler Heated Square footage <20,000 sq ft	100	0.09	3.47
Electric Steam Boiler	Heating Equipment = Electric Boiler Building Built = before 1970 Heated Square footage <20,000 sq ft	61	0.06	0.84

* Natural gas or LPG boiler.
** Note that the total of these records and corresponding number of houses is not equivalent to DOE's residential boiler sample weights, which represent the number of boiler shipments in 2021.

Table 7A.3.2 Selection of CBECS 2003 Records for Boilers (New Construction)

Product Class	Algorithm	No. of Records	RECS 2009	DOE 2021
			Number of Houses *million***	Number of Boiler Shipments *thousands*
Gas-Fired Hot Water Boilers	Heating Equipment = Gas Boiler Heated Square footage <20,000 sq ft Building Age ≥ 1990	21	0.02	5.22
Gas-Fired Steam Boilers	NA*	0	0.00	0.00
Oil-Fired Hot Water Boilers	Heating Equipment = Oil Boiler Heated Square footage <20,000 sq ft Building Age ≥ 1990	10	0.02	0.53
Oil-Fired Steam Boilers	NA*	0	0.00	0.00
Electric Hot Water Boiler	Heating Equipment = Electric Boiler Heated Square footage <20,000 sq ft Building Age ≥ 1990	15	0.01	2.24
Electric Steam Boiler	NA*	0	0.00	0.00

* DOE assumed that there are no steam boilers in the new construction market.
** Note that the total of these records and corresponding number of houses is not equivalent to DOE's residential boiler sample weights, which represent the number of boiler shipments in 2021.

Table 7A.3.3 shows the derivation of adjustment factors used to determine the shipment-weighted building sample weights. The adjustment factors are derived as the ratio of the un-shipment weighted gas-fired or oil-fired boilers sample total to the average AHRI shipments by state (see Table 7A.2.3). This factor is then multiplied to each building in the gas-fired or oil-fired boiler sample.

Table 7A.3.3 Shipment-Weighted Adjustment Factors for Gas-fired and Oil-fired Boiler Commercial Sample based on AHRI Shipments by State

ID	Census Division	Gas-fired Hot Water and Steam Boilers			Oil-fired Hot Water and Steam Boilers		
		2008-2012 Shipments Fraction	HWGB and SGB Sample (Unweighted)	Shipment-Weighted Adjustment Factor	2008-2012 Shipments Fraction	HWOB and SOB Sample (Unweighted)	Shipment-Weighted Adjustment Factor
1	New England	20.85%	7.09%	2.939	46.56%	37.09%	1.255
2	Middle Atlantic	47.96%	26.89%	1.783	40.50%	36.65%	1.105
3	East North Central	12.72%	27.37%	0.465	1.10%	3.98%	0.276
4	West North Central	4.43%	10.00%	0.443	0.36%	15.94%	0.022
5	South Atlantic	6.91%	7.53%	0.918	9.28%	2.32%	4.004
6	East South Central	0.27%	3.16%	0.086	0.04%	0.00%	1.000
7	West South Central	0.29%	2.65%	0.111	0.07%	0.00%	1.000
8	Mountain	3.55%	6.78%	0.523	0.17%	0.49%	0.338
9	Pacific	3.02%	8.52%	0.354	1.93%	3.53%	0.546

Table 7A.3.4 shows the final commercial sample weights by Census division.

Table 7A.3.4 Final Commercial Sample Weights by Census Division

ID	Census Division	Gas-fired Hot Water Boilers		Gas-fired Steam Boilers	Oil-fired Hot Water Boilers		Oil-fired Steam Boilers
		Replace.	New Const.	Replace.	Replace.	New Const.	Replace.
1	New England	20.85%	0.00%	25.29%	46.61%	64.01%	45.33%
2	Middle Atlantic	47.96%	26.01%	45.83%	40.55%	26.74%	41.52%
3	East North Central	12.72%	19.73%	12.27%	1.10%	0.00%	1.42%
4	West North Central	4.43%	23.78%	3.34%	0.36%	0.39%	0.37%
5	South Atlantic	6.91%	0.00%	7.43%	9.29%	0.00%	10.25%
6	East South Central	0.27%	0.00%	0.20%	0.00%	0.00%	0.00%
7	West South Central	0.29%	1.94%	0.24%	0.00%	0.00%	0.00%
8	Mountain	3.55%	8.53%	3.13%	0.17%	1.20%	0.00%
9	Pacific	3.02%	20.01%	2.28%	1.93%	7.67%	1.11%

7A.3.1 CBECS 2003 Variables and Values

Table 7A.3.5 CBECS 2003 Variables Used for Boilers

Variable	Description
Location Variables	
CENDIV8	Census division
HDD658	Heating degree days (base 65)
CDD658	Cooling degree days (base 65)
REGION8	Census region
Household Characteristics Variables	
PUBID8	Building identifier
ADJWT8	Final full sample building weight
YRCON8	Year of construction category
SQFT8	Square footage category
PBA8	Principal building activity
OWNER8	Owner
MAINHT8	Main heating equipment
HEATP8	Percent heated
BOILP8	Percent heated by boilers
BOILER8	Boilers inside the building
NGHT18	Natural gas used for main heating
NGHT28	Natural gas used for secondary heating
ELHT18	Electricity used for main heating
ELHT28	Electricity used for secondary heating
FKHT18	Fuel oil used for main heating
FKHT28	Fuel oil used for secondary heating
NWMNHT8	Main heating replaced since 1990
ELWATR8	Electricity used for water heating
NGWATR8	Natural gas used for water heating
FKWATR8	Fuel oil used for water heating
NGHTBTU8	Natural Gas heating use (mBtu)
FKHTBTU8	Fuel Oil heating use (mBtu)
ELHTBTU8	Electric heating use (mBtu)
NGWTBTU8	Natural Gas water heating use (mBtu)
FKWTBTU8	Fuel Oil water heating use (mBtu)
ELWTBTU8	Electric water heating use (mBtu)
StationID*	ID number of weather station identified with household (see appendix 7C)

7A.3.2 CBECS 2003 Database Variable Response Codes

Table 7A.3.6 provides the response codes for all CBECS 2003 variables used in the residential boiler sample.

Table 7A.3.6 CBECS 2003 Variable Response Codes

Variable	Response Codes	
PUBID8	Unique identifier for each respondent	
ADJWT8	Final sample weight	
REGION8	01	Northeast
	02	Midwest
	03	South
	04	West
CENDIV8	01	New England
	02	Middle Atlantic
	03	East North Central
	04	West North Central
	05	South Atlantic
	06	East South Central
	07	West South Central
	08	Mountain
	09	Pacific
YRCON8	1	Before 1920
	2	1920 to 1945
	3	1946 to 1959
	4	1960 to 1969
	5	1970 to 1979
	6	1980 to 1989
	7	1990 to 1999
	8	2000 to 2003
	9	2004
SQFT8	0-9999999996	0,000,000,009
	9999999997	Not ascertained
	9999999998	Refused
	9999999999	Don't know
HDD658	Heating degree days in 2003, base temperature 65F	
CDD658	Cooling degree days in 2003, base temperature 65F	
PBA8	01	Vacant
	02	Office
	04	Laboratory
	05	Nonrefrigerated warehouse
	06	Food sales
	07	Public order and safety
	08	Outpatient health care
	11	Refrigerated warehouse
	12	Religious worship
	13	Public assembly
	14	Education
	15	Food service
	16	Inpatient health care
	17	Nursing
	18	Lodging
	23	Strip shopping mall

Variable	Response Codes	
	24	Enclosed mall
	25	Retail other than mall
	26	Service
	91	Other
OWNER8	01	Property management company
	02	Other corporation/partnership/LLC
	03	Religious organization
	04	Other non-profit organization
	05	Privately-owned school
	06	Individual owner
	07	Other nongovernment owner
	08	Federal government
	09	State government
	10	Local government
MAINHT8	1	Furnaces that heat air directly
	2	Boilers inside the building
	3	Packaged heating units
	4	Individual space heaters
	5	Heat pumps for heating
	6	District steam or hot water
	7	Other heating equipment
HEATP8	0-996	009
	997	Not ascertained
	998	Refused
	999	Don't know
BOILP8	0-996	009
	997	Not ascertained
	998	Refused
	999	Don't know
BOILER8	1	Yes
	2	No
	7	Not Ascertained
	8	Refused
	9	Don't Know
NGHT18	1	Yes
	2	No
	7	Not Ascertained
	8	Refused
	9	Don't Know
NGHT28	1	Yes
	2	No
	7	Not Ascertained
	8	Refused
	9	Don't Know
ELHT18	1	Yes
	2	No
	7	Not Ascertained

Variable	Response Codes
	8 Refused 9 Don't Know
ELHT28	1 Yes 2 No 7 Not Ascertained 8 Refused 9 Don't Know
FKHT18	1 Yes 2 No 7 Not Ascertained 8 Refused 9 Don't Know
FKHT28	1 Yes 2 No 7 Not Ascertained 8 Refused 9 Don't Know
NWMNHT8	1 Yes 2 No 7 Not Ascertained 8 Refused 9 Don't Know
ELWATR8	1 Yes 2 No 7 Not Ascertained 8 Refused 9 Don't Know
NGWATR8	1 Yes 2 No 7 Not Ascertained 8 Refused 9 Don't Know
FKWATR8	1 Yes 2 No 7 Not Ascertained 8 Refused 9 Don't Know
NGHTBTU8	Thousand BTU
FKHTBTU8	Thousand BTU
ELHTBTU8	Thousand BTU
NGWTBTU8	Thousand BTU
FKWTBTU8	Thousand BTU
ELWTBTU8	Thousand BTU
StationID	Three character identifier for weather station

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3. Air-Conditioning Heating and Refrigeration Institute (AHRI). *2003-2012 Residential Boilers Shipments Data (Provided to Lawrence Berkeley National Laboratory)*. 2013.

APPENDIX 7B. DETERMINATION OF RESIDENTIAL BOILER ENERGY USE IN THE LCC ANALYSIS

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APPENDIX 7B. DETERMINATION OF RESIDENTIAL BOILER ENERGY USE IN THE LCC ANALYSIS

7B.1 INTRODUCTION

For calculating the energy consumed by residential boilers, the U.S. Department of Energy (DOE) considered the energy use associated with providing space heating and domestic water heating. The boiler space heating energy consumption methodology is based on DOE's test procedure for furnaces and boilers, which references the American Society for Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) 103-2007 *"Method of Testing for Annual Fuel Efficiency of Residential Central Furnaces and Boilers",* to accurately reflect field operation.[1,2] In addition, DOE developed a methodology for estimating the water heating energy use provided by boilers. The calculation used for the determination of the total energy use per unit is as follows:

$$EnergyUse_{Total} = FuelUse_{SH} + FuelUse_{WH} + ElecUse_{Total}$$

Eq. 7B.1

Where:

$FuelUse_{SH}$ = fuel used for space heating,
$FuelUse_{WH}$ = fuel used for water heating, and
$ElecUse_{Total}$ = electrical energy use, including increased cooling load effect on air conditioning (AC) products.

This appendix provides the detailed space heating fuel use, water heating fuel use, and total electricity use calculation methodology.

7B.2 DETERMINATION OF SPACE HEATING ANNUAL ENERGY CONSUMPTION

The average annual fuel consumption ($FuelUse_{SH}$) is calculated in DOE's test procedure (assuming that the product does not have a continuous pilot ignition):[a]

$$FuelUse_{SH} = \begin{cases} BOH_{SS} \times Q_{IN}, \text{for single-stage boilers} \\ (BOH_H \times Q_{IN}) + (BOH_R \times Q_{IN,R}), \text{for two-stage boilers} \\ (BOH_M \times Q_{IN,M}) + (BOH_R \times Q_{IN,R}), \text{for continuous modulating}^{b} \text{ boilers} \end{cases}$$

Eq. 7B.2

---

[a] Residential gas-fired boilers manufactured on or after September 1, 2012 are not permitted to have a constant burning pilot light.

[b] In this analysis, "continuous modulating" term is used instead of "step-modulating." Both terms are interchangeably used in the literature.

Where:

BOH_{SS} = national average number of burner operating hours (see derivation in section 7B.2.1),
BOH_H = national average number of burner operating hours at the maximum operating mode for two-stage boilers (see derivation in section 7B.2.1),
BOH_R = national average number of burner operating hours at the reduced operating mode for two-stage or continuous modulating boilers (see derivation in section 7B.2.1),
BOH_M = national average number of burner operating hours at the modulating operating mode for continuous modulating boilers (see derivation in section 7B.2.1),
Q_{IN} = steady-state nameplate input rate in Btu/h for single-stage boilers or steady-state nameplate maximum input rate in Btu/h for two-stage and continuous modulating boilers (see derivation in section 7B.2.3),
$Q_{IN,R}$ = steady-state reduced fuel input rate, and
$Q_{IN,M}$ = steady-state modulating fuel input rate.

Determination of burner operating hours is determined in section 7B.2.1. Q_{IN} is based on the product sizing for the baseline equipment for each product class as discussed in section 7B.2.3. DOE assumed $Q_{IN,R}$ to be 70 percent of Q_{IN} for two-stage products, and 40 percent of Q_{IN} for modulating products, based on manufacturer product literature. $Q_{IN,M}$ is calculated by dividing $Q_{OUT,M}$ by $Effy_{SS,M}$ (as defined in section 11.4.8.9 and 11.5.8.8 in the ASHRAE 103-2007 test procedure, respectively).

7B.2.1 Determination of National Average Number of Burner Operating Hours (BOH)

From DOE's test procedure, the national average number of burner operating hours for boilers is calculated in (assuming that the product does not have a continuous pilot ignition[c]):

[c] For factor B, in the expanded equation, if $Q_P = 0$ (pilot flame fuel input rate in Btu/h), then $B = 0$, which is true for all boiler product classes in this analysis.

$$BOH_{SS} = 2080 \times 0.77 \times A \times \left(\frac{Q_{OUT}}{1+a}\right)$$, for single-stage boilers,

$$BOH_H = X_H \times 2080 \times 0.77 \times A_H \times \left(\frac{Q_{OUT}}{1+a}\right)$$, for two-stage boilers at the maximum operating mode,

$$BOH_R = X_R \times 2080 \times 0.77 \times A_R \times \left(\frac{Q_{OUT}}{1+a}\right)$$, for two-stage and continuous modulating boilers operating at the reduced operating mode, and

$$BOH_M = X_H \times 2080 \times 0.77 \times A_M \times \left(\frac{Q_{OUT}}{1+a}\right)$$, for continuous modulating boilers operating at the modulating operating mode,

Eq. 7B.3

Where:

2080 = national average heating load hours,
0.77 = adjustment factor to adjust the calculated design heating requirements and heating load hours to the actual heating load experienced by the heating system,
A = 100,000/ [341300(y_P * PE + y_{IG} *PE_{IG} + y * BE) + Q_{IN} * $Effy_{HS}$],
A_H = 100,000/ [341300($y_{P,H}$ * PE_H + $y_{IG,H}$ *$PE_{IG,H}$ + y * BE_H) + Q_{IN} * $Effy_{U,H}$],
A_R = 100,000/ [341300($y_{P,R}$ * PE_R + $y_{IG,R}$ *$PE_{IG,R}$ + y_R * BE_R) + $Q_{IN,R}$ * $Effy_{U,R}$],
A_M = 100,000/ [341300($y_{P,H}$ * PE_H + $y_{IG,H}$ *$PE_{IG,H}$ + y * BE_H) + $Q_{IN,M}$ * $Effy_{U,M}$],
Q_{OUT} = maximum fuel input rate heating capacity (see Eq. 7B.6),
α = oversize factor set to the national average value of 0.7,
X_H = fraction of heating load at maximum fuel input rate operating mode as defined in section 11.4.8.5 of ASHRAE 103-2007,
X_R = fraction of heating load at reduced fuel input rate operating mode, which equals 1-X_H,
Q_{IN} = as defined in Eq. 7B.2,
$Q_{IN,R}$ = as defined in Eq. 7B.2,
$Q_{IN,M}$ = as defined in Eq. 7B.2,
y_P = ratio of induced or forced draft blower on-time to average burner on-time,
$y_{P,R}$ = ratio of induced or forced draft blower on-time to average burner on-time, measured at the reduced fuel input rate,
PE = burner (or draft inducer) electrical power input at full-load steady-state operation in kW,
PE_H = burner (or draft inducer) electrical power input at full-load steady-state operation in kW, measured at the maximum fuel input rate,
PE_R = burner (or draft inducer) electrical power input at full-load steady-state operation in kW, measured at the reduced fuel input rate,
y_{IG} = ratio of burner interrupted-ignition device on-time to average burner on-time,
$y_{IG,H}$ = ratio of burner interrupted-ignition device on-time to average burner on-time, measured at the maximum fuel input rate,
$y_{IG,R}$ = ratio of burner interrupted-ignition device on-time to average burner on-time, measured at the reduced fuel input rate,
PE_{IG} = electrical input rate to the interrupted ignition device on the burner in kW,

$PE_{IG,H}$ = electrical input rate to the interrupted ignition device on the burner, measured at the maximum fuel input rate in kW,
$PE_{IG,R}$ = electrical input rate to the interrupted ignition device on the burner, measured at the reduced fuel input rate in kW,
y = pump on-time to burner on-time,
y_R = pump on-time to burner on-time, measured at the reduced fuel input rate,
BE = water pump electrical energy input rate at full-load steady-state operation in kW,
BE_R = water pump electrical energy input rate at full-load steady-state operation in kW, measured at the reduced fuel input rate,
BE_H = water pump electrical energy input rate at full-load steady-state operation in kW, measured at the maximum fuel input rate.
$Effy_{HS}$ = heating seasonal efficiency,
$Effy_{U,H}$ = average part load efficiency at the maximum fuel input rate, which is equal to $Effy_{HS}$,
$Effy_{U,R}$ = average part load efficiency at the reduced fuel input rate, and
$Effy_{U,M}$ = average part load efficiency at the modulating fuel input rate.

In Eq. 7B.3, the national average values for the parameters heating load (2,080 hours), adjustment factor (0.77), and oversize factor (α), along with Q_{OUT}, are used to calculate the building heating load derived from DOE's test procedure, which can be expressed as:

$$BHL_{NationalAverage} = 2080 \times 0.77 \times \left(\frac{Q_{OUT}}{1+a}\right)$$

Eq. 7B.4

For each sampled building in this analysis, DOE calculated the building heating load experienced by each individual boiler using the energy use data from RECS 2009 and CBECS 2003 rather than the national average parameters used in Eq. 7B.3. Therefore, in the LCC spreadsheet, $BHL_{NationalAverage}$ is substituted by the building heating load served by a single boiler (BHL_{Boiler}).

Thus, Eq. 7B.3 was modified in the LCC spreadsheet as follows (note that the $BOH_{SH,i}$ is the same as BOH_{SS}, BOH_H, BOH_R, or BOH_M depending on operating mode)[d]:

$$BOH_{SH,i} = X_i \times \frac{BHL_{Boiler}}{Q_{Useful,i}}$$

Eq. 7B.5

Where:

X_i = 1 for BOH_{SS} and X_H and X_R (as defined above), which are the fraction of heating load at maximum or reduced operating mode,

[d] Maximum value for BOH is set to 8760

BHL_{Boiler} = building heating load served by a single boiler (kBtu/yr), as described in chapter 7 and section 7B.2.2, and

$Q_{Useful,i}$ = A, A_H, A_R, or A_M (as defined in Eq. 7B.3), which are the total useful energy output of the boiler, including useful heat from auxiliary electrical components for each operating mode (kBtu/hr).[e]

DOE calculated X_H by using T_C (balance-point temperature as defined in section 11.4.8.4 of ASHRAE 103-2007[1]), α (the oversize factor), Q_{OUT}, and $Q_{OUT,R}$ (reduced fuel input rate heating capacity). $Q_{OUT,R}$ is set equal to 70 percent of Q_{OUT} for two-stage equipment and 40 percent of Q_{OUT} for modulating equipment. X_R is set equal to 1-X_H. Q_{OUT} is proportional to Q_{IN}, and the constant of proportionality is an adjusted value of AFUE, ($AFUE + a$ in equation Eq. 7B.6), which is derived using data from the 2015 AHRI Directory for residential boilers, for each product class:[3]

$$Q_{OUT} = Q_{IN}(AFUE_{adj} + a)$$

Eq. 7B.6

Where:

Q_{IN} = as defined in Eq. 7B.2,

$AFUE_{adj}$ = AFUE of the new boiler as defined in Eq. 7B.11, and

a = linear regression fit parameter (based on the reduced boiler set of models, see appendix 7d), where for:

- non-condensing gas-fired hot water boilers, a = 0.22,
- condensing gas-fired hot water boilers, a = -0.35,
- gas-fired steam boilers, a = 0.28,
- oil-fired hot water boilers, a = 0.83, and
- oil-fired steam boilers, a = 1.26.

To calculate factors A, A_H, A_R, A_M in the LCC spreadsheet, DOE calculated y_P, $y_{P,R}$, PE, PE_R, PE_H, y_{IG}, $y_{IG,R}$, PE_{IG}, $PE_{IG,R}$, $PE_{IG,H}$, y, y_R, BE, BE_R, BE_H, PE, y_{IG}, PE_{IG}, y, BE, and Q_{IN}, as described in Eq. 7B.3. DOE calculated $Effy_{HS}$, heating seasonal efficiency, as defined in sections 11.2.11, 11.3.11.3, 11.4.11.3, and 11.5.11.3 of ASHRAE 103-2007. $Effy_{HS}$ is equal to the annual fuel utilization efficiency ($AFUE$) for the boilers in this analysis because they do not have a continuous pilot. DOE assumed that $Effy_{U,H}$ is equal to $Effy_{U,R}$ and therefore using the equation in section 11.5.11.3 of ASHRAE 103-2007 is equal to $Effy_{SS}$. $Effy_{U,M}$ is calculated using the equation in section 11.4.9.2.3 of ASHRAE 103-2007. DOE calculated the steady-state efficiency ($Effy_{SS}$) using Q_{OUT} (as defined in Eq. 7B.6), K (factor that adjust the jacket losses), and L_J (jacket loss value, where 1 percent is the default value), by revising the equation described in section 11.2.8.1 of ASHRAE 103-2007 as follows:

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[e] For this analysis, DOE assumed that for boilers in conditioned space a fraction of the standby power is useful heat in the heating season.

$$Effy_{SS} = \frac{Q_{OUT}}{Q_{IN}} + K \times L_J$$

Eq. 7B.7

Where:

Q_{OUT} = as defined in Eq. 7B.6,
Q_{IN} = as defined in Eq. 7B.2,
K = factor that adjusts jacket loss measured in the laboratory to those that would be measured under outdoor design conditions, which is assumed to be 0 for boilers installed in a conditioned space and 1.7 for boilers intended to be installed as isolated combustion systems (*i.e.,* installed in an unconditioned space) according to ASHRAE 103-2007, and
L_J = jacket loss value, which is assumed to be 1 percent according to ASHRAE 103-2007.

Based on RECS 2009 information, DOE estimated the installation location of each boiler sampled (see appendix 8C for more details).[f] DOE assumed that unconditioned installation locations included garages or unconditioned basements.

7B.2.2 Determination of Building Heating Load Estimates for Boilers

The annual building heating load (BHL_{Boiler}) is the total amount of heat output from the boiler that the house or building needs during the heating season.[g] This includes heat from the burner as well as other electrical components. DOE determined projected BHL_{Boiler} in 2021 for each sampled housing unit or building, based on the efficiency of the assigned existing boiler, using the following calculation:

$$BHL_{Boiler} = \frac{\left(Q_{YR} \times AFUE_{ex,adj}\right) \times Adj_{Factor(s)}}{BoilerCount} \times NumberofUnitsServed$$

Eq. 7B.8

Where:

Q_{YR} = annual fuel consumption for heating based on RECS 2009 or CBECS 2003 (kBtu/yr),
$AFUE_{ex,adj}$ = AFUE of the existing boiler ($AFUE_{ex}$) adjusted for return water temperature[h] (see section 7B.2.4.3),
$Adj_{Factor(s)}$ = adjustment factor (see section 7B.2.2.1),
BoilerCount = number of boilers used to fulfill the building heating load, and
NumberofUnitsServed = number of housing units served by a single boiler.

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[f] DOE assumed that all residential boilers in commercial applications would be installed in a conditioned space.
[g] BHL_{Boiler} is the load served by a single boiler. DOE assumed that some houses and buildings would be served by multiple residentially-sized boilers based on RECS 2009 data.
[h] Return water temperature represents the average annual return water temperature for the different space heating applications.

The AFUE of the existing boiler ($AFUE_{ex}$) is determined by matching historical AFUE data to the reported age of the existing boiler determined using RECS 2009 and CBECS 2003 variables. See section 7B.2.4 for more details.

DOE applied adjustment factors to account for changes in building shell efficiency, average climate conditions, climate change, and secondary heating products. See section 7B.2.2.1 for more details.

In the case when a household or building was determined to have multiple boilers, the building heating load was divided by the number of boilers.

7B.2.2.1 Adjustment Factors for the Building Heating Load

Building Shell Efficiency Index. DOE adjusted BHL_{Boiler} to reflect the expectation that buildings in 2021 will have a somewhat different BHL_{Boiler} than the buildings in the RECS 2009 and CBECS 2003 boiler sample. The adjustment involves multiplying the calculated BHL_{Boiler} for each RECS 2009 or CBECS 2003 unit by a building shell efficiency index[i] derived from the National Energy Modeling System (NEMS) simulation performed for the Energy Information Administration's (EIA) *Annual Energy Outlook 2015* (*AEO 2015)*.[4] For the year 2021, the factor applied for homes is 0.91 for both replacements and new construction. Table 7B.2.1 shows the residential building shell efficiency index from *AEO 2015* from 2012 to 2040. The factor applied for commercial building depends on building type and census division. For replacements in commercial buildings, the factor ranges from 0.72 to 0.95 (as shown in Table 7B.2.2). For new construction commercial buildings, the factor used ranges from 0.34 to 0.85. Table 7B.2.3 shows the mapping of NEMS commercial building types to the commercial building types reported in CBECS 2003. This means that the average home or commercial building in 2021 will have a lower heating load than one in 2009 for residential buildings and 2003 for commercial buildings.

[i] The building shell efficiency index sets the heating load value at 1.00 for an average home in 2009 for residential buildings and 2003 for commercial buildings (by type) in each census division. The values listed in Table 7B.2.1 and Table 7B.2.2 represent the change in heating load based on the difference in physical size and shell attributes for homes in the future (which takes into account physical size difference and efficiency gains from better insulation and windows).

Table 7B.2.1 Residential Building Shell Efficiency Index (based on AEO 2015 Reference Case)

Year	Pre-2009 Homes	New Construction
2012	0.97	0.98
2013	0.96	0.91
2014	0.96	0.99
2015	0.95	0.97
2016	0.95	0.93
2017	0.94	0.90
2018	0.94	0.90
2019	0.93	0.90
2020	0.92	0.91
2021	**0.91**	**0.91**
2022	0.91	0.91
2023	0.90	0.91
2024	0.89	0.92
2025	0.89	0.92
2026	0.88	0.91
2027	0.88	0.91
2028	0.87	0.92
2029	0.86	0.92
2030	0.86	0.92
2031	0.85	0.92
2032	0.85	0.92
2033	0.84	0.92
2034	0.83	0.92
2035	0.83	0.92
2036	0.82	0.92
2037	0.81	0.92
2038	0.81	0.92
2039	0.80	0.92
2040	0.79	0.92

Table 7B.2.2 2021 Commercial Building Shell Index for Replacements Based on Building Type and Census Division (based on AEO 2015 Reference Case)

NEMS Building ID	NEMS Building Type	Commercial Building Shell Index								
		Census Division								
		1	*2*	*3*	*4*	*5*	*6*	*7*	*8*	*9*
1	Assembly	0.94	0.91	0.93	0.91	0.89	0.85	0.85	0.91	0.72
2	Education	0.91	0.89	0.91	0.88	0.89	0.83	0.85	0.90	0.80
3	Food Sales	0.94	0.93	0.95	0.93	0.93	0.91	0.93	0.94	0.93
4	Food Service	0.93	0.93	0.93	0.93	0.93	0.93	0.94	0.93	0.93
5	Health Care	0.91	0.90	0.91	0.90	0.90	0.89	0.89	0.93	0.83
6	Lodging	0.92	0.90	0.91	0.92	0.91	0.89	0.90	0.93	0.90
7	Large Office	0.94	0.92	0.94	0.94	0.90	0.90	0.87	0.92	0.77
8	Small Office	0.91	0.89	0.91	0.89	0.89	0.85	0.88	0.90	0.82
9	Merc Service	0.93	0.91	0.92	0.92	0.92	0.89	0.89	0.93	0.77
10	Warehouse	0.87	0.90	0.86	0.90	0.87	0.89	0.86	0.83	0.80
11	Other	0.90	0.90	0.91	0.88	0.88	0.79	0.80	0.88	0.72

Table 7B.2.3 Mapping of Commercial NEMS Index IDs to CBECS 2003 PBA ID

CBECS 2003 (PBA_ID)	CBECS 2003 (PBA_Value)	NEMS_ID	NEMS Value
1	Vacant	11	Other
2	Office	8	Small Office
4	Laboratory	11	Other
5	Nonrefrigerated warehouse	10	Warehouse
6	Food sales	3	Food Sales
7	Public order and safety	1	Assembly
8	Outpatient health care	5	Health Care
11	Refrigerated warehouse	10	Warehouse
12	Religious worship	1	Assembly
13	Public assembly	1	Assembly
14	Education	2	Education
15	Food service	4	Food Service
16	Inpatient health care	5	Health Care
17	Nursing	5	Health Care
18	Lodging	6	Lodging
23	Strip shopping mall	9	Merc Service
24	Enclosed mall	9	Merc Service
25	Retail other than mall	9	Merc Service
26	Service	9	Merc Service
91	Other	11	Other

Average Climate Conditions. DOE also adjusted the calculated BHL_{Boiler} to reflect historical average climate conditions by using heating degree days (HDD) reported in RECS 2009 and CBECS 2003 for each building and National Oceanic and Atmospheric Administration (NOAA) historic HDD data by region:[5]

$$Adj_{Factor,avg\ climate} = \frac{HDD_{10yr\ avg}}{HDD_{bldg,2009\ or\ 2003}}$$

Eq. 7B.9

Where:

$HDD_{bldg,\ 2009\ or\ 2003}$ = HDD in 2009 for RECS 2009 or 2003 for CEBCS 2003 for the specific region where the unit is located, and,

$HDD_{10yr\ avg}$ = 10-year average HDD (2005–2014) based on NOAA data for the specific region where the unit is located.

As shown in Table 7B.2.4, the historical average climate conditions adjustment factors for residential buildings range from 0.15 to 1.02 and have an average of 0.97 for the boiler building sample (*i.e.*, 2009 was in general colder than the 10-year average). As shown in Table 7B.2.5, this adjustment factor for commercial buildings range from 0.90 to 1.07 and average 0.97 for the boiler building sample (*i.e.*, 2003 was in general colder than the 10-year average).

Table 7B.2.4 HDD Adjustment Factors by RECS 2009 Regions (based on NOAA data)

Region	States	2009 HDD	10-Year Avg. (2005-2014)	HDD Adjustment Factor
1	CT, ME, NH, RI, VT	7138	6749	0.95
2	Massachusetts	6383	6037	0.95
3	New York	6235	5927	0.95
4	New Jersey	5294	5082	0.96
5	Pennsylvania	5880	5676	0.97
6	Illinois	6385	6141	0.96
7	Indiana, Ohio	5888	5717	0.97
8	Michigan	7036	6725	0.96
9	Wisconsin	7890	7552	0.96
10	IA, MN, ND, SD	8393	8014	0.95
11	Kansas, Nebraska	6039	5727	0.95
12	Missouri	5176	5011	0.97
13	Virginia	4431	4260	0.96
14	DE, DC, MD	4735	4541	0.96
15	Georgia	2981	2863	0.96
16	NC, SC	3441	3310	0.96
17	Florida	705	690	0.98
18	AL, KY, MS	4162	4074	0.98
19	Tennessee	3903	3810	0.98
20	AR, LA, OK	2060	2058	1.00
21	Texas	1849	1825	0.99
22	Colorado	7354	7122	0.97
23	ID, MT, UT, WY	8147	7829	0.96
24	Arizona	1894	1937	1.02
25	NV, NM	4288	4269	1.00
26	California	2879	2822	0.98
27	OR, WA	5916	5717	0.97
28	Alaska	10594	10381	0.98
29	Hawaii	0	0	0.15
30	West Virginia	5233	5111	0.98

Table 7B.2.5 HDD Adjustment Factors by CBECS 2003 Census Divisions (based on NOAA data)

ID	Division Name	2003 HDD	10-Year Avg. (2004-2013)	HDD Adjustment Factor
1	New England	7149	6454	0.90
2	Middle Atlantic	6284	5681	0.90
3	East North Central	6739	6502	0.96
4	West North Central	7780	7727	0.99
5	South Atlantic	4829	4441	0.92
6	East South Central	4052	3938	0.97
7	West South Central	2065	1958	0.95
8	Mountain	6517	6799	1.04
9	Pacific	5319	5667	1.07

Climate Change. DOE also accounted for future climate trends based on *AEO 2015* HDD projections by Census division (as shown in Table 7B.2.6), which show a decline in HDD, leading to lower projected BHL_{Boiler} in 2021 relative to the non-climate-trend-adjusted BHL_{Boiler} values. DOE used 2015 as the base year of the projected and calculated HDD adjustment factors as shown in for each census division in Table 7B.2.7.

Table 7B.2.6 Projected HDD by Census Divisions from AEO 2015

Year	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	United States
2012	5561	4970	5356	5515	2307	2876	1650	4574	3412	3772
2013	6424	5836	6622	7134	2732	3649	2328	5271	3377	4469
2014	6795	6307	7309	7428	3031	4048	2553	4810	2787	4639
2015	6346	5699	6267	6508	2737	3532	2205	4790	2983	4221
2016	6115	5503	6066	6401	2627	3369	2013	4922	3486	4181
2017	6093	5484	6054	6393	2619	3364	2003	4910	3484	4165
2018	6072	5465	6041	6384	2611	3359	1994	4899	3482	4150
2019	6051	5446	6028	6376	2603	3354	1985	4887	3479	4134
2020	6030	5427	6016	6367	2595	3349	1975	4874	3477	4119
2021	**6009**	**5409**	**6003**	**6358**	**2586**	**3344**	**1966**	**4862**	**3474**	**4103**
2022	5988	5390	5991	6349	2578	3340	1956	4849	3471	4088
2023	5966	5371	5978	6340	2569	3335	1947	4836	3469	4072
2024	5945	5352	5965	6331	2560	3330	1938	4823	3466	4057
2025	5924	5333	5953	6322	2552	3325	1928	4809	3463	4042
2026	5903	5314	5940	6313	2543	3320	1919	4796	3461	4026
2027	5882	5295	5928	6303	2534	3316	1910	4782	3458	4011
2028	5860	5276	5915	6294	2526	3311	1901	4769	3455	3996
2029	5839	5258	5903	6285	2517	3306	1891	4755	3453	3981
2030	5818	5239	5890	6275	2508	3301	1882	4741	3450	3966
2031	5796	5220	5877	6266	2500	3296	1873	4727	3448	3951
2032	5775	5201	5865	6257	2491	3291	1864	4713	3445	3937
2033	5754	5183	5852	6247	2483	3286	1854	4698	3443	3922
2034	5732	5164	5840	6238	2475	3281	1845	4684	3440	3907
2035	5711	5146	5827	6229	2466	3276	1836	4669	3438	3893
2036	5689	5127	5814	6219	2458	3271	1827	4654	3435	3878
2037	5668	5109	5802	6210	2450	3266	1818	4639	3433	3864
2038	5646	5090	5789	6200	2441	3261	1809	4625	3431	3849
2039	5625	5072	5776	6191	2433	3256	1800	4610	3428	3834
2040	5603	5054	5764	6181	2425	3251	1790	4595	3426	3820

Table 7B.2.7 Climate Change HDD Adjustment Factors by Census Division*

Year	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific	United States
2011	0.91	0.90	0.88	0.86	0.88	0.85	0.82	0.93	0.98	0.90
2012	1.05	1.06	1.09	1.11	1.04	1.08	1.16	1.07	0.97	1.07
2013	1.11	1.15	1.20	1.16	1.15	1.20	1.27	0.98	0.80	1.11
2014	1.04	1.04	1.03	1.02	1.04	1.05	1.10	0.97	0.86	1.01
2015	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
2016	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
2017	0.99	0.99	1.00	1.00	0.99	1.00	0.99	1.00	1.00	0.99
2018	0.99	0.99	0.99	1.00	0.99	1.00	0.99	0.99	1.00	0.99
2019	0.99	0.99	0.99	0.99	0.99	0.99	0.98	0.99	1.00	0.99
2020	0.98	0.98	0.99	0.99	0.98	0.99	0.98	0.99	1.00	0.98
2021	**0.98**	**0.98**	**0.99**	**0.99**	**0.98**	**0.99**	**0.97**	**0.99**	**1.00**	**0.98**
2022	0.98	0.98	0.99	0.99	0.98	0.99	0.97	0.98	1.00	0.97
2023	0.97	0.97	0.98	0.99	0.97	0.99	0.96	0.98	0.99	0.97
2024	0.97	0.97	0.98	0.99	0.97	0.99	0.96	0.98	0.99	0.97
2025	0.97	0.97	0.98	0.99	0.97	0.99	0.95	0.97	0.99	0.96
2026	0.96	0.96	0.98	0.98	0.96	0.98	0.95	0.97	0.99	0.96
2027	0.96	0.96	0.98	0.98	0.96	0.98	0.94	0.97	0.99	0.96
2028	0.95	0.96	0.97	0.98	0.96	0.98	0.94	0.97	0.99	0.95
2029	0.95	0.95	0.97	0.98	0.95	0.98	0.93	0.96	0.99	0.95
2030	0.95	0.95	0.97	0.98	0.95	0.98	0.93	0.96	0.99	0.95
2031	0.94	0.95	0.97	0.98	0.95	0.98	0.93	0.96	0.99	0.94
2032	0.94	0.94	0.96	0.98	0.95	0.98	0.92	0.95	0.99	0.94
2033	0.94	0.94	0.96	0.97	0.94	0.97	0.92	0.95	0.99	0.93
2034	0.93	0.94	0.96	0.97	0.94	0.97	0.91	0.95	0.99	0.93
2035	0.93	0.93	0.96	0.97	0.94	0.97	0.91	0.95	0.99	0.93
2036	0.93	0.93	0.96	0.97	0.93	0.97	0.90	0.94	0.98	0.92
2037	0.92	0.92	0.95	0.97	0.93	0.97	0.90	0.94	0.98	0.92
2038	0.92	0.92	0.95	0.97	0.93	0.97	0.89	0.94	0.98	0.92
2039	0.92	0.92	0.95	0.97	0.92	0.96	0.89	0.93	0.98	0.91
2040	0.91	0.90	0.88	0.86	0.88	0.85	0.82	0.93	0.98	0.90

* Base year = 2016

Secondary Heating. DOE determined that some of the sampled buildings used multiple heating products with the same fuel as the boiler(s), such as a central furnace, wall furnace, room heater, stove, or fireplace. Therefore, DOE adjusted the calculated BHL_{Boiler} when necessary to reflect the use of secondary heating products using the same fuel as the boiler(s). The adjustment factors are calculated using reported survey information from both RECS 2009 and CBECS 2003 regarding the fraction of heating that was met by different heating products. RECS 2009 reports the amount of heating that is provided by the main heating product (using the variable EQMAMT, see appendix 7A). For each of the reported bins, DOE created a triangular distribution representing the fraction of secondary heating product energy use. CBECS 2003 reports the fraction heating energy use by the boiler with the variable BOILP8 (see appendix 7A).

7B.2.3 Derivation of Input Capacity of Existing and New Boilers

To estimate the heating load of each sample housing unit, DOE assigned an input capacity to the boiler in the RECS 2009 and CBECS 2003 sample building units.

To support this analysis, DOE established a methodology for deriving the boiler capacities of each of the sampled buildings. Boilers are typically sized according to the outdoor environmental conditions and specific building characteristics.[j] For this analysis, DOE established the input capacity of the existing boiler using the following equation:

$$Q_{in} = \frac{AdjustedHeatLoad}{AFUE_{baseline}} \times ShipmentsAdjustmentFactor$$

Eq. 7B.10

Where:

AdjustedHeatLoad = estimated building heat loss adjusted for building characteristics (kBtu/h),
$AFUE_{baseline}$ = AFUE of the baseline boiler for each product class, and
ShipmentsAdjustmentFactor = varies from 1.45 to 1.87 by product class, based on shipments data from Burnham.[6]

The Department calculated the adjusted heat load for each sample housing/building unit based on the applicable building characteristics and outdoor conditions derived from the RECS and CBECS data. Applicable building characteristics include the building square footage, building vintage, foundation type, shell characteristics, number of floors, outdoor design temperature, reported insulation category, and two factors that correct the building heating loss.

DOE utilized information from several boiler manufacturers and distributors to develop a methodology to derive the total heat loss of the building (*i.e.*, adjusted heat load). The following steps describe how the boiler adjusted heat loss was determined:

1) DOE first determined the vintage of the sampled building using RECS/CBECS. DOE aggregated the building vintage in to four separate bins, and then associated a construction design number with each bin. The construction design number represents building shell and construction characteristics applicable to the corresponding vintage. Details of the relationship developed between building vintage, shell, and construction characteristics can be found in Table 7B.2.8.
2) Next, using information gathered from RECS 2009/CBECS 2003, for each sampled building, DOE determined the number of floors (including heated basements) and the

[j] DOE assumed that a replacement boiler installed in a particular household would have the same input capacity as the existing boiler regardless of efficiency level. This might lead to some households being significantly oversized for higher efficiency products.

total square footage. DOE then calculated the square footage of each floor by dividing the total square footage by the number of floors.

3) Using the construction design number and the floor square footages, DOE selected a heat loss value for each floor based on a design temperature difference of 70°F (See Table 7B.2.9).[k]

4) To adjust the building total heat loss value to account for the design temperature difference other than 70°F and for the first floor heat loss in multiple story buildings, DOE applied the design temperature correction factor and ceiling correction factor from Weil-Mclain's *Boiler Replacement Guide* (see Table 7B.2.10 and Table 7B.2.11).[7]

5) Once the adjusted heat loss value for each floor was determined, DOE summed the results of all floors to establish the total adjusted heat load of the sampled building.

Table 7B.2.8 Construction Characteristics by Vintage

Frame Construction Characteristics				
Construction Vintage	**Construction Design Number**	**Weather-Stripped Glass**	**Insulation Thickness**	
			Wall	**Ceiling**
<1959	1	Single	1"	2"
1960-1974	2	Double	1"	2"
1975-1999	7	Double	3"	6"
2000-2009	12	Double	3"	9"

[k] The design temperature difference is equal to the indoor temperature setting (70°F) minus the outdoor design temperature (0°F).

Table 7B.2.9 Heat Loss by Construction Characteristics (Total Btu)

Heat Loss (Btu)				
Floor Area	**Construction Design Number**			
Sq. Ft.	**1**	**2**	**7**	**12**
500	28,750	23,900	17,910	14660
600	32,300	27,030	20,460	16650
700	35,860	30,150	23,010	18630
800	39,840	33,590	25,760	20800
900	43,340	36,680	28,270	22750
1000	46,890	39,800	30,820	24740
1100	50,450	42,920	33,370	26730
1200	54,000	46,040	35,920	28720
1300	56,640	48,470	38,030	30300
1400	60,200	51,590	40,580	32280
1500	62,830	54,030	42,690	33870
1600	65,530	56,490	44,840	35490
1700	68,590	59,250	47,140	37250
1800	71,720	62,040	49,490	39060
1900	73,930	64,150	51,400	40460
2000	77,050	66,940	53,750	42270
2100	79,325	69,136	55,808	43,853
2200	81,733	71,393	57,824	45,359
2300	84,051	73,583	59,799	46,827
2400	86,279	75,705	61,732	48,257
2500	88,417	77,759	63,622	49,649
2600	90,464	79,745	65,471	51,003
2700	92,422	81,662	67,277	52,318
2800	94,290	83,512	69,042	53,596
2900	96,068	85,294	70,765	54,836
3000	97,756	87,008	72,445	56,038
3100	99,353	88,654	74,084	57,202
3200	100,861	90,231	75,680	58,328
3300	102,279	91,741	77,235	59,416
3400	103,607	93,183	78,748	60,466
3500	104,845	94,557	80,218	61,478
3600	105,992	95,863	81,647	62,452
3700	107,050	97,100	83,033	63,387
3800	108,018	98,270	84,378	64,285
3900	108,896	99,372	85,681	65,145
4000	109,684	100,406	86,941	65,967
4100	110,381	101,372	88,160	66,751
4200	110,989	102,269	89,336	67,497
4300	111,507	103,099	90,471	68,205
4400	111,935	103,861	91,564	68,875
4500	112,273	104,555	92,614	69,507

Table 7B.2.10 Design Temperature Difference Correction Factors

Design Temp. Difference	Factor	Design Temp. Difference	Factor	Design Temp. Difference	Factor
25°F	0.35	55°F	0.78	90°F	1.29
30°F	0.42	60°F	0.85	95°F	1.36
35°F	0.5	65°F	0.92	100°F	1.43
40°F	0.57	75°F	1.07	105°F	1.5
45°F	0.64	80°F	1.15	110°F	1.57
50°F	0.71	85°F	1.2	115°F	1.64

Table 7B.2.11 Ceiling Correction Factors

Construction Number	Factor
1	0.82
2	0.79
7	0.88
12	0.91

To approximate input capacity values similar to shipment weighted values, DOE used shipments data provided by Burnham.[6] Burnham presented shipment information (shown below in Table 7B.2.12) of their aggregated subsidiaries indicating the average input capacity sold in for each product class. DOE used the values provided by Burnham to derive adjustment factors (*ShipmentsAdjustmentFactor*) by product class that adjust the calculated input capacity to achieve an average input capacity as given from Burnham. The resulting baseline input capacity values are shown in Table 7B.2.13. Table 7B.2.14 shows the comparison of these results to shipment weighted data and data from the reduced set of boiler models (see appendix 7d).

Table 7B.2.12 Average input capacity for all units shipped from all three Burnham subsidiaries of residential boilers[6]

DOE Product Class	Average Input (btu/h)
Gas-fired Hot Water Boiler (HWGB)	120,198
Oil-fired Hot Water Boiler (HWOB)	144,221
Gas-fired Steam Boiler (SGB)	143,804
Oil-fired Steam Boiler (SOB)	162,255

Table 7B.2.13 Range of Derived Input Capacity for Each Boiler Product Class, kBtu/hr

Product Class	Min	Max	Average	Percentiles				
				5%	25%	50%	75%	95%
Gas-Fired Hot Water Boilers	30.0	300.0	120.4	40.0	70.0	110.0	160.0	250.0
Gas-Fired Steam Boilers	30.0	300.0	144.0	50.0	90.0	130.0	190.0	280.0
Oil-Fired Hot Water Boilers	30.0	300.0	144.3	60.0	100.0	140.0	180.0	270.0
Oil-Fired Steam Boilers	30.0	300.0	162.3	70.0	110.0	150.0	200.0	300.0
Electric Hot Water Boilers	30.0	300.0	152.2	40.0	70.0	130.0	210.0	300.0
Electric Steam Boilers	30.0	300.0	131.2	40.0	70.0	100.0	160.0	300.0

Table 7B.2.14 Comparison of Derived Input Capacity to Shipment-Weighted Data and Model Data, kBtu/hr

Product Class	DOE Derived Average		2013 DOE Boiler Models*		Shipment Weighted Output Capacity for Cast Iron Boilers**			
	Input Capacity	Output Capacity	Input Capacity	Output Capacity	1970	1980	1990	2000
Gas-Fired Hot Water Boilers	120	105	149	129	124	122	113	116
Gas-Fired Steam Boilers	144	117	181	149	153	153	138	139
Oil-Fired Hot Water Boilers	144	123	172	149	148	154	147	144
Oil-Fired Steam Boilers	162	136	189	161	176	164	169	152
Electric Hot Water/Steam Boilers	152/131	149/129	NA	NA	NA	NA	NA	NA

* Based on reduced data set of residential boiler models (see appendix 7D).
** Based on AHRI (formerly GAMA) shipment data provided in April 2002.

7B.2.4 Derivation of Existing AFUE

The AFUE of the existing boiler is required to calculate the building heating load. DOE developed the historical distributions of efficiencies for existing boilers based on historical shipment data by efficiency from the Air-Conditioning, Heating, and Refrigeration Institute (AHRI)[1], the distribution of models in historical versions of the AHRI certification directory, and ENERGY STAR® shipments.

7B.2.4.1 Methodology

Distributions of boiler efficiency were determined from 1978 to 2009. For the year 1978, DOE used average AFUE data that was used in the 1980 DOE rulemaking for both gas-fired hot water boilers and oil-fired hot water boilers.[8] The shipment-weighted efficiencies in 1978 are 65 percent for gas-fired hot water boilers and 76 percent for oil-fired hot water boilers.

[1] Formerly the Gas Appliance Manufacturers Association (GAMA).

The efficiency distributions for 1991 and 1992 were determined using data from the 1991 and 1992 AHRI certification directories.[9] The AFUE distributions correspond to the ratio of models by efficiency levels.

Shipment data were available for 2001.[10] The distributions of the efficiencies for which shipment data were not available were based on data from the 2001 AHRI certification directory.[9] Table 7B.2.16 shows the historical shipment data of residential boilers by efficiency level in 2001 from AHRI.[10]

Table 7B.2.15 Percent of Shipments in 2001 by Efficiency Level Reported by AHRI

Gas-Fired Hot Water		Gas-Fired Steam		Oil-Fired Hot Water		Oil-Fired Steam	
AFUE	Shipments	AFUE	Shipments	AFUE	Shipments	AFUE	Shipments
80	35%	78-79	33%	80-82	16%	80-82	24%
81	22%	80	46%	83-85	70%	83-85	76%
82	14%	81-83	21%	86-87	14%		
83	15%						
84	8%						
85	1%						
87-95	6%						

Market penetration data were available for ENERGY STAR-compliant models from 2003 to 2009.[m] For 2009, the efficiency distribution was originally assessed using data from 2009 AHRI certification directory, which was then scaled to take into account the portion of the market that was ENERGY STAR-compliant.[9] The distributions from 2003 to 2008, are based on a linear interpolation between 2002 and 2009, and were scaled to take into account the portion of the market that was ENERGY STAR-compliant for each year.

The ENERGY STAR program for residential boilers began on June 4, 1996, and the performance criterion for both gas-fired and oil-fired ENERGY STAR boilers was set at 85-percent AFUE.[12] On October 1, 2014, new ENERGY STAR criteria became effective. For gas-fired boilers, the criterion was set at 90-percent AFUE. For oil-fired boilers, the criterion was set at 87-percent AFUE.[7] Table 7B.2.17 shows the market penetrations and shipments of ENERGY STAR-qualified residential boilers from 2003-2014, as well as the fraction of all manufacturers that reported shipment data to ENERGY STAR. Some of the growth in higher efficiency boilers has been due to incentive programs (*e.g.*, Federal tax incentives, State and utility incentives). Federal tax credits started in 2005 and remained in effect until December 31, 2014.[13]

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[m] AHRI provided number of gas-fired condensing boiler shipments from 2003-2012.[11] DOE used this data to validate its approach, but did not use it directly because the data is confidential and did not include all the manufacturers.

As shown in Table 7B.2.18, DOE used total shipment estimates by product class (derived from the shipment model described in chapter 9) to calculate the ENERGY STAR fractions used in the analysis.[n]

Table 7B.2.16 Market Penetrations of ENERGY STAR-Qualified Residential Boilers

Year	ENERGY STAR Market Share		ENERGY STAR Shipments		% of Manufacturers Reporting
	Gas Boiler	Oil Boiler	Gas Boiler	Oil Boiler	Gas & Oil Boiler
2003	31%	75%	48,769	89,441	79%
2004	41%	71%	96,000	115,000	90%
2005	25%	51%	55,091	83,434	81%
2006	34%	67%	68,102	84,668	81%
2007	39%	61%	76,309	99,226	100%
2008	57%	62%	109,605	75,151	95%
2009	46%	62%	88,000	76,000	100%
2010	52%	61%	100,000	75,000	98%
2011	42%	52%	82,000	64,000	93%
2012	57%	47%	109000	57,000	98%
2013	67%	44%	129,000	53,000	98%
2014	61%	32%	117,000	39,000	92%

[n] DOE's calculations of ENERGY STAR market share is different primarily because of DOE's estimated historical residential boiler shipments, which is different from what ENERGY STAR used. For example, all shipments after 2008 are based on no growth from a baseline of total units shipped as quoted in the 56th Annual Report from Appliance Magazine, dated May 2009, which is the last publicly available data. In addition, DOE increased the ENERGY STAR shipments by taking into account manufacturers that did not report data, which ENERGY STAR does not do in its accounting of the market share.

Table 7B.2.17 DOE-Estimated Market Penetrations of ENERGY STAR-Qualified Residential Boilers by Product Class

Year	DOE Estimated Shipments (see chapter 9)				DOE Estimated Fraction of ENERGY STAR Qualified Boilers			
	HWGB	SGB	HWOB	SOB	HWGB	SGB	HWOB	SOB
2003	246,117	38,395	162,933	17,706	25.1%	0.0%	65.7%	34.7%
2004	271,044	37,139	180,915	19,460	39.4%	0.0%	66.8%	35.6%
2005	254,835	37,435	164,894	17,256	26.7%	0.0%	59.1%	32.4%
2006	231,573	30,504	136,518	16,016	36.3%	0.0%	72.4%	35.4%
2007	235,551	34,236	128,240	15,494	32.4%	0.0%	73.2%	34.8%
2008	257,479	40,132	100,177	12,375	44.8%	0.0%	74.7%	34.7%
2009	202,737	29,192	84,778	10,758	43.4%	0.0%	84.8%	38.3%
2010	203,742	27,237	86,690	11,132	50.1%	0.0%	83.5%	37.3%
2011	211,835	31,786	79,883	10,162	41.6%	0.0%	81.5%	36.7%
2012	243,167	35,397	65,555	8,371	45.7%	0.0%	83.9%	37.7%
2013	241,475	32,535	83,562	9,987	54.4%	0.0%	61.0%	29.4%
2014	240,454	32,054	82,475	9,793	52.9%	0.0%	48.4%	23.5%
				2-year average	53.7%	0.0%	54.7%	26.5%

The distributions from 1978 to 1991, 1992 to 2001, and 2002 to 2009 are based on a linear interpolation.

7B.2.4.2 Results

Figure 7B.2.1 shows the distribution of AFUE from 1978 to 2009 by AFUE bins for gas-fired hot water boilers. The rapid drop of AFUE below 80 percent between 1991 and 1992 is due to the passage of a new efficiency standard.

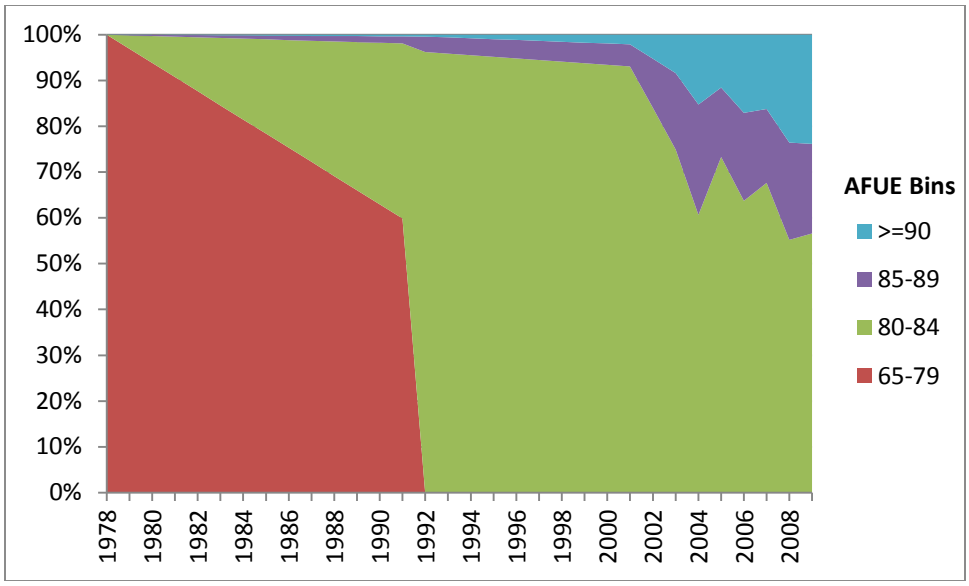

Figure 7B.2.1 AFUE distributions for Hot Water Gas-fired Boilers by Year from 1978 to 2009

Figure 7B.2.2 shows the shipment-weighted AFUE for gas-fired hot water, gas-fired steam, oil-fired hot water, and oil-fired steam boilers.

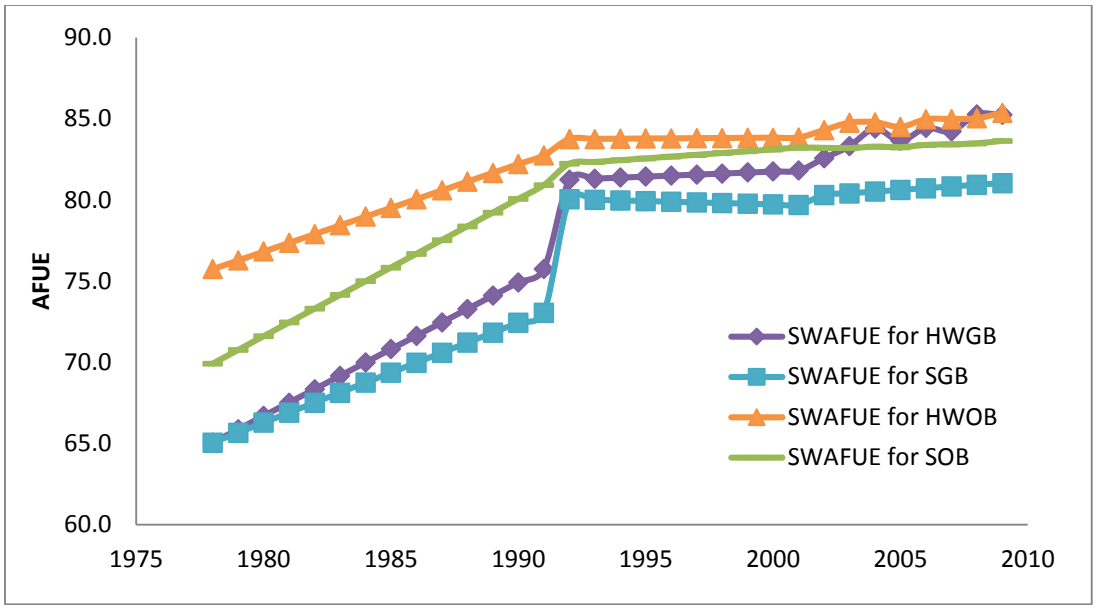

Figure 7B.2.2 Shipment-Weighted AFUE (SWAFUE) for Gas-Fired Hot Water Boilers (HWGB), Gas-Fired Steam (SGB), Oil-Fired Hot Water Boilers (HWOB) and Oil-Fired Steam (SOB)

7B.2.4.3 Determination of Adjusted AFUE ($AFUE_{ex,adj}$ and $AFUE_{adj}$)

DOE adjusted the AFUE of the existing and new boiler to reflect the variation in efficiency in different hydronic space heating applications by associating a specific space heating application with each sampled household or building. The field-adjusted AFUE of the existing and new boiler ($AFUE_{ex,adj}$ and $AFUE_{adj}$, respectively) were adjusted depending on the return water temperature (RWT), automatic means for adjusting water temperature, jacket losses, and excess air using the following equation:

$$AFUE_{ex,adj} = AFUE_{ex} + Adj_{RWT_{AutomaticMeans}} + Adj_{JacketLosses} + Adj_{ExcessAir}$$

$$AFUE_{adj} = AFUE_{new} + Adj_{RWT_AutomaticMeans} + Adj_{JacketLosses} + Adj_{ExcessAir}$$

Eq. 7B.11

Where:

$AFUE_{ex}$ = the rated AFUE of the existing boiler,
$AFUE_{new}$ = the rated AFUE of the new boiler to be installed,
$Adj_{RWT_AutomaticMeans}$= adjustment factors for RWT and automatic means (see section 0),
$Adj_{JacketLosses}$ = adjustment factor for jacket losses (see section0), and
$Adj_{ExcessAir}$ = adjustment factor field excess air (see section 0).

Adjustment of Boiler AFUE Based on Return Water Temperature Applications and Automatic Means

The residential boilers considered in this rulemaking utilize a variety of distribution systems, the designs of which depend on the age and design of the home, the type of boiler used, and building and climate characteristics.

Most hydronic heat distribution systems include the boiler, distribution piping, and heat emitters (finned-tube convective baseboards, panel radiators, in-floor radiant tubing, or fan-coil convectors).[14] Each system is designed to accommodate a specific supply water temperature depending on the heat emitter type. For example, fan-coil units are recommend to operate with supply water at 180-200°F, finned-tube baseboards at 140-190°F, and in-slab radiant floors at 100-140°F.[15] This analysis assumed that a temperature difference between supply and return water temperature (RWT) of 20°F is typical of most of the emitters described above. Boiler thermal efficiency decreases for both condensing and non-condensing products as return water temperatures increases.[16]

Several condensing boiler manufacturers publish the relationship between boiler thermal efficiency and RWT for specific boiler series.[17,18,19,20,21,22] Burnham also provided test data from one condensing boiler and one non-condensing boiler.[6] This information was used to develop an average efficiency vs. RWT relationship representative of boiler performance for a range of return water temperatures. The analysis assumes that AFUE scales according to the relationship reported for the thermal efficiency. Figure 7B.2.3 and Figure 7B.2.4 present the information obtained from manufacturers and the derived average efficiency curve for non-condensing and condensing boilers, respectively.[o]

[o] The average efficiency curve represents the mean efficiency at each return water temperature reported in the manufacturers' information.

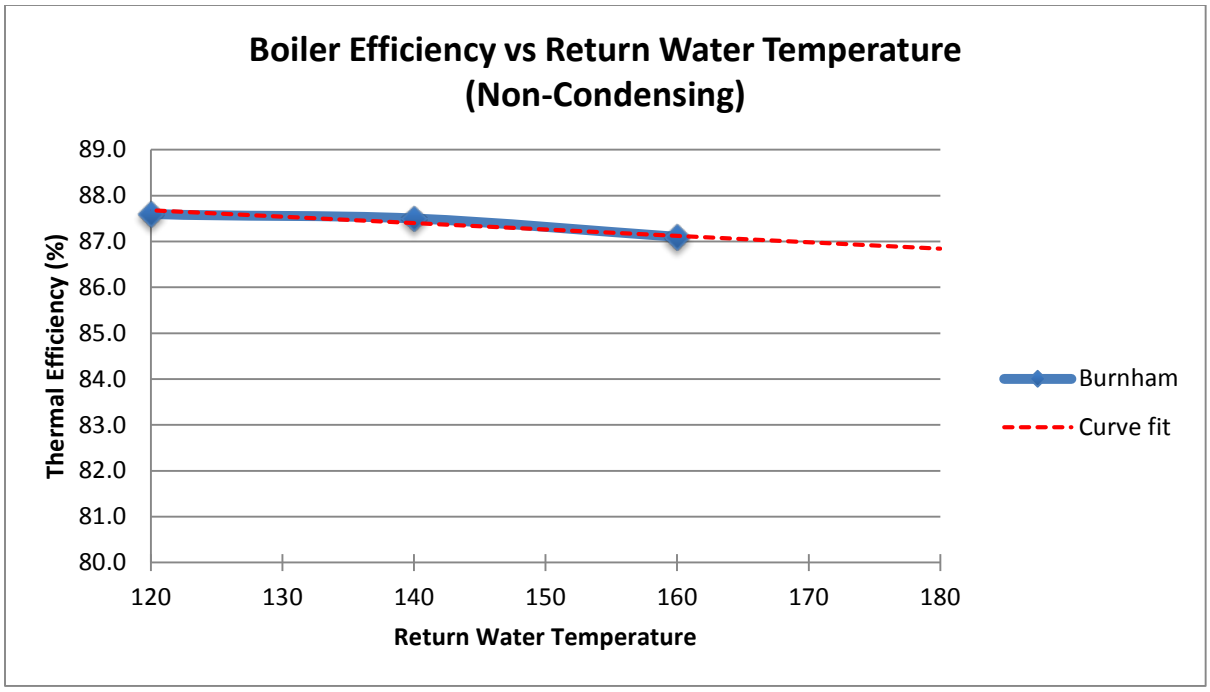

Figure 7B.2.3 Non-Condensing Boilers Efficiency vs. Return Water Temperature

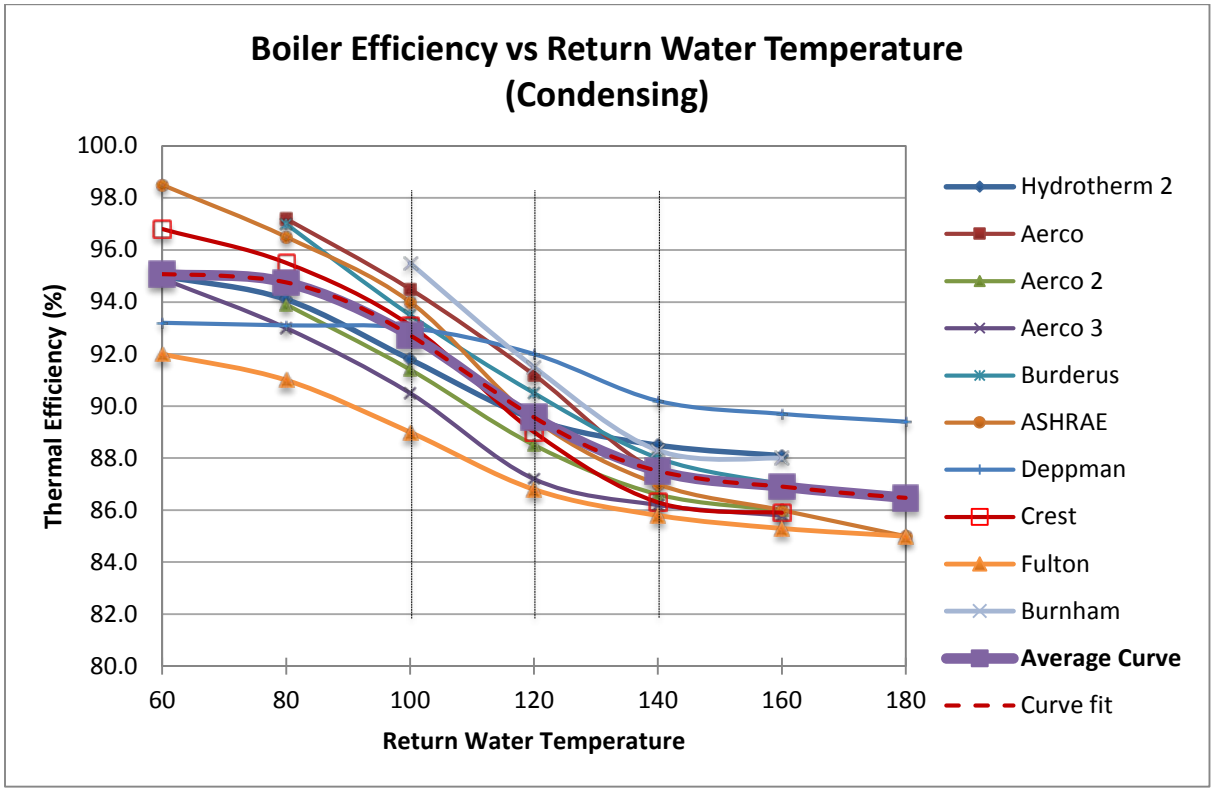

Figure 7B.2.4 Condensing Boilers Efficiency vs. Return Water Temperature

Based on the average efficiency versus RWT relationships shown in Figure 7B.2.3 and Figure 7B.2.4, DOE developed separate factors for condensing and non-condensing products to adjust the reported AFUE based on high, medium, and low RWT applications experienced in the field. For both condensing and non-condensing boilers, the medium water temperature point reflects the reported boiler performance as rated according to the DOE test procedure (RWT of 120-124°F). For non-condensing boilers, only two RWT applications, medium and high, were used, as non-condensing boilers are not typically used in low temperature applications. The low and high annual operating temperatures were assumed to be 110°F for in-slab radiant (low) and 160°F for finned tube baseboard (high) applications.

Both temperatures were reduced to account for the use of an automatic means for adjusting water temperature (automatic means). To adjust the RWTs to account for automatic means, DOE considered how manufacturers are fulfilling this requirement for both single-stage and modulating boilers.

Single Stage Boilers

The majority of single-stage products sampled utilized a pre-purge control function that allows the purging of residual heat within the boiler prior to ignition of the burner. DOE also found that the majority of boiler models sampled incorporate a time limit and a low temperature limit function within the control strategy. The time limits range from two to three minutes (by default), with some boilers allowing for user defined durations. The low temperature limit is commonly set at a default temperature between 135°F and 140°F for non-condensing boilers.[p]

Based on these findings, DOE calculated the reduction in average RWT (T_R) for single-stage products according to Eq. 7B.12:

$$T_R = T_A - ((T_A * X_{AT}) + (T_{LL} * X_{RT}))$$

Eq. 7B.12

Where:

T_R = water temperature reduction applied to the average single-stage RWT,
T_A = average return water temperature for application,
T_{LL} = low return water temperature during automatic means operations,
X_{AT} = fraction of boiler operation per hour at average return water temperature, and
X_{RT} = fraction of boiler operation per hour at reduced return water temperature,

DOE calculated the fraction of burner operating hours at average return water temperature using Eq. 7B.13.

$$X_{AT} = 1 - X_{RT}$$

Eq. 7B.13

[p] DOE assumed the same temperature reduction of 25°F for condensing boilers applying the pre-purge control strategy on low return water temperature applications.

Where:

X_{AT} = as defined in equation Eq. 7B.12, and
X_{RT} = as defined in equation Eq. 7B.12.

DOE calculated the fraction of burner operating hours at reduced return water temperature using Eq. 7B.14.

$$X_{RT} = \frac{T_{A_{ON}} * C}{60}$$

Eq. 7B.14

Where:

X_{RT} = as defined in equation Eq. 7B.12,
T_{AON} = automatic means on-time per cycle,
C = number of cycles per hour (equal to two according to ASHRAE 103-2007), and
60 = minutes per hour (used to convert to fraction of on-time per hour).

For single-stage non-condensing boilers, DOE used the non-condensing boiler test data provided by Burnham Holdings.[6] The analysis used the efficiency/RWT relationship at the 140-180°F temperature range to establish the efficiency adjustment required for high temperature applications for single-stage non-condensing boiler. Linear regression was used on the data between 80°F and 160°F to define the relationship. As shown in Figure 7B.2.3, the relationship resulted in a reduction in AFUE of about 0.53 percent from 120°F (med) to 158°F (high).

Two-Stage and Modulating Boilers

For two-stage and modulating products, a review of manufacturer literature found outdoor temperature reset to be the most common means for adjusting water temperature. DOE assumed an average reduction of 10°F, resulting in an average annual low RWT of 100°F for multi-stage boiler operations using in-slab radiant systems.

For two-stage and modulating condensing boilers, the analysis used the average relationship shown in Figure 7B.2.5 to establish the magnitude of the efficiency adjustment required for the high and low temperature applications. As shown in Figure 7B.2.5, the relationship indicates an increase of 3.15-percent thermal efficiency from 120°F (med) to 100°F (low) and a decrease of 2.06-percent thermal efficiency from 120°F (low) to 140°F (high).

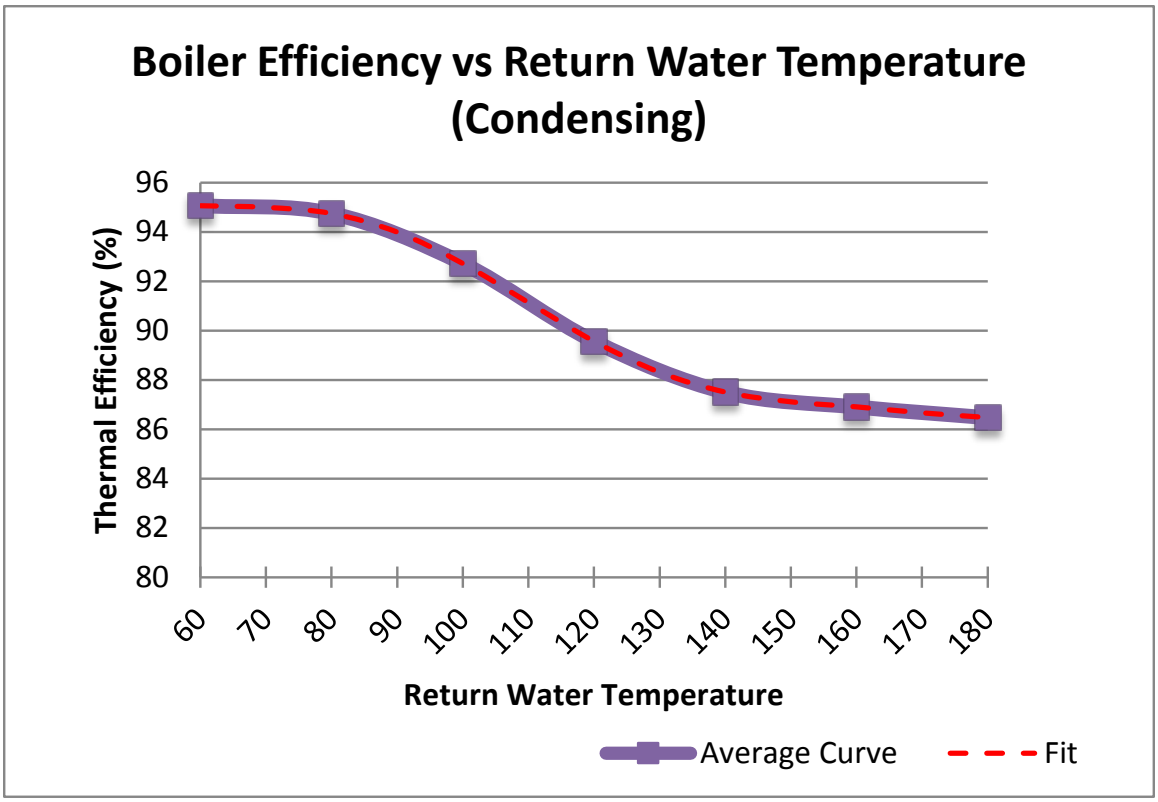

Figure 7B.2.5 Average Curve for Condensing Boilers

Table 7B.2.19 and Table 7B.2.20 summarize the AFUE adjustments used in the analysis. The adjusted AFUE values reflect the efficiency of boilers for the fraction of households and buildings that utilize hydronic heat distribution systems that operate at return water temperatures other than 120°F.

Table 7B.2.18 Adjustment to Existing AFUE Based on RWT Application and Automatic Means Option for Single-Stage Boilers

	Low RWT (108°F)	Medium RWT (120°F)	High RWT w/ Automatic Means (158°F)*	High RWT w/o Automatic Means (160°F)*
Non-Condensing (single-stage)	-	As Reported	-0.53%	-0.56%
Condensing (single-stage)	1.90%	As Reported	-2.62%	-2.66%

* 160°F RTW is applied to all existing equipment, which is assumed to be without automatic means. 158°F RWT is applied to new equipment which must include automatic means options.

Table 7B.2.19 Adjustment to Existing AFUE Based on RWT Application and Automatic Means Option for Two-Stage/Modulating Boilers

	Low RWT (100°F)	Medium RWT (120°F)	High RWT (140°F)
Non-Condensing (2-stage/modulating)	-	As Reported	-0.28%
Condensing (2-stage/modulating)	3.15%	As Reported	-2.06%

After determining the AFUE adjustment based on RWT, DOE applied the adjustment factors to the boiler population based on boiler vintage. High RWT is applied to 100 percent of non-condensing boiler installations. For condensing boiler installations, low RWT is applied to 100 percent of new construction and new owners and 10 percent of replacement installations. Of the low temperature applications operate on average at 100°F. DOE assumed that all other condensing boiler installations would be in high RWT applications.

Adjustment of Boiler AFUE Based on Jacket Loss

DOE adjusted the AFUE to account for boiler jacket losses that do not contribute to space heating. The jacket loss factors were only applied to boilers installed in non-conditioned spaces (*i.e.*, unconditioned basement or garage). See appendix 8C for details about how DOE determined the installation location of boilers. From ASHRAE 103-2007 sections 11.2.6 and 11.2.11, the jacket loss factor (C_J) of 2.4 for boilers intended to be installed as isolated combustion systems is applied to high mass boilers, while C_J of 0.5 for finned-tube boilers intended to be installed as isolated combustion systems is applied to low mass boilers. C_J is multiplied by the jacket loss (L_J), which DOE assumed is 0.5 percent. ASHRAE 103-2007 assigns a default value for L_J of 1 percent, but input from manufacturers and test data suggest that this value could be smaller. DOE assumed that 90 percent of condensing boilers and 10 percent of non-condensing boilers are low-mass. Table 7B.2.21 summarizes the reduction in AFUE points from jacket losses during the heating season.

Table 7B.2.20 Boiler Jacket Loss Factors

Installation	Boiler Type	Jacket Loss Factor for Boiler
Conditioned	Low Mass	0%
	High Mass	0%
Non-Conditioned	Low Mass	0.25%
	High Mass	1.20%

Adjustment of Boiler AFUE Based on Excess Air

DOE accounted for differences in excess air between the test procedure and field conditions. DOE assumed that the increased excess air level in the field would be based on the assumed stack temperature and draft type, and would reduce AFUE between 0.0 percent and 1.6 percent. DOE assumed that boilers at high fire operate at 15 to 20 percent excess air based on an article in the ASHRAE Journal.[23] DOE used the relationship between excess air, stack

temperature, and combustion efficiency from the Engineering Toolbox shown below in Table 7B.2.22.[24]

Table 7B.2.21 Relationship Between Excess Air, Stack Temperature, and Combustion Efficiency from the Engineering Toolbox

Excess (%)		Net Stack Temperature (°F)				
Air	Oxygen	200	300	400	500	600
9.5	2.0	85.4	83.1	80.8	78.4	76.0
15	3.0	85.2	82.8	80.4	77.9	75.4
20	3.8	85.0	82.5	80.1	77.4	74.9
28.1	5.0	84.7	82.1	79.5	76.7	74.0
44.9	7.0	84.1	81.2	78.2	75.2	72.1
81.6	10.0	82.8	79.3	75.6	71.9	68.2

Based on these two sources, DOE made the following assumptions. For natural draft boilers below 86 percent AFUE, DOE assumed 20 percent excess air and 400°F stack temperature, resulting in a triangular distribution of AFUE impact from 0 percent to 1.6 percent (0.8 percent average). For non-condensing mechanical draft boilers and natural draft boilers above 86-percent AFUE, DOE assumed 15 percent excess air and 400°F stack temperature, resulting in half of the impact on AFUE compared to natural draft boilers below 86 percent AFUE, with a 0.4 percent average. For condensing boilers, DOE assumed 15 percent excess air and 200°F stack temperature, resulting in half of the impact on AFUE compared to non-condensing mechanical draft boilers (0.2 percent average).

7B.3 DETERMINATION OF WATER HEATING ANNUAL ENERGY CONSUMPTION

Residential boilers are often used to provide domestic hot water in addition to space heating. The most common means of doing so are through an indirect water heater, tankless coil, or as an integrated part of the boiler.

RECS 2009 and CBECS 2003 do not provide any information about when a boiler is used to provide hot water. DOE determined that a fraction of the installations in buildings in RECS 2009 or CBECS 2003 that use the same fuel for both space and water heating also use boilers for water heating by matching the sample data to a 2015 Air-Conditioning, Heating, and Refrigeration Institute (AHRI) contractor survey.[25] DOE determined that water heating would be provided by a boiler when RECS 2009 or CBECS 2003 reports the use of storage tank water heating in 50 percent of gas-fired hot water boilers, 5 percent of gas-fired steam boilers, 40 percent of oil-fired hot water boilers, and 5 percent of oil-fired steam boilers. DOE determined that water heating would be provided by a boiler when RECS 2009 or CBECS 2003 reports the use of tankless water heating in all cases except for oil-fired steam boilers, in which case half of these installations would have water heating provided by the boiler. DOE had no data for electric boilers, so it assumed the same assumptions as for gas boilers. Table 7B.3.1 lists the resulting

fractions of boilers used for water heating by product class, as well as the results from AHRI's contractor survey.

Table 7B.3.1 Fraction of Residential Boilers Used for Water Heating

Product Class	DOE's Analysis Fraction of Boilers Used for Water Heating	AHRI's Contractor Survey Fraction of Boilers Used for Water Heating
Gas-Fired Hot Water Boilers	41.1%	39.4%
Gas-Fired Steam Boilers	4.6%	4.9%
Oil-Fired Hot Water Boilers	35.9%	34.9%
Oil-Fired Steam Boilers	9.4%	9.3%
Electric Hot Water Boiler	26.6%	-
Electric Steam Boiler	2.2%	-

DOE calculated the energy use of water heaters using a simplified energy equation based on the Water Heater Analysis Model (WHAM).[26] WHAM accounts for a range of operating conditions and energy efficiency characteristics of water heaters. To describe energy efficiency characteristics of water heaters, WHAM uses three parameters that also are used in the DOE water heater test procedure:[27] recovery efficiency (*RE*), standby heat-loss coefficient (*UA*), and rated input power (P_{ON}). Water heater operating conditions are indicated by the daily hot water draw volume, inlet water temperature, thermostat setting, and air temperature around the water heater (ambient air temperature).

The WHAM equation yields average daily water heater energy consumption (Q_{in}). The equation is expressed as follows.

$$FuelUse_{WH,daily} = \frac{vol \times den \times C_P \times (T_{tank} - T_{in})}{RE} \times \left(1 - \frac{UA \times (T_{tank} - T_{amb})}{P_{on}}\right) + 24 \times UA \times (T_{tank} - T_{amb})$$

Eq. 7B.15

Where:

Q_{in} = total water heater energy consumption in British thermal units per day, Btu/day,
RE = recovery efficiency, percent,
P_{ON} = rated input power, Btu/h,
UA = standby heat-loss coefficient, Btu/h-°F,
T_{tank} = thermostat set point temperature, °F,
T_{in} = inlet water temperature, °F,
T_{amb} = temperature of the ambient air, °F,
vol = volume of hot water drawn in 24 hours, gal/day,
den = density of stored water, set constant at 8.29 pounds per gallon, lb/gal, and
C_P = specific heat of stored water, set constant at 1.000743, Btu/lb-°F.

DOE simplified this equation and converted it to annual energy use by setting

$WHL = vol \times den \times C_P \times (T_{tank} - T_{in})$, $AFUE - Adj_{FactorWH} = RE$, $WH_{loss} = UA \times (T_{tank} - T_{amb})$, and $Q_{IN} = P_{on}$:

$$FuelUse_{WH} = \frac{WHL}{AFUE - Adj_{FactorWH}} \times \left(1 - \frac{WH_{loss}}{Q_{IN}}\right) + 8760 \times WH_{loss}/1000$$

Eq. 7B.16

Where:

WHL = water heating energy use based on RECS 2009 or CBECS 2003 (see Eq. 7B.18), MMBtu/yr,
AFUE = AFUE of the selected efficiency level, and
$Adj_{FactorWH}$ = adjustment factor to account for the difference between the AFUE and water heating efficiency (recovery efficiency) (see Eq. 7B.17),
WH_{loss} = average water heater standby loss, kbtu/h,
Q_{IN} = as defined in Eq. 7B.2,
8760 = total hours in a year, and
1000 = conversion factor from kBtu/h to MMBtu/h.

The average water heater standby loss (WH_{loss}) is assumed to be 0.5 kBtu/h for an indirect tank and 0.0 kBtu/h for others (including tankless designs).

DOE accounted for the difference between AFUE and recovery efficiency using the following equation:

$$Adj_{FactorWH} = Adj_{AFUE-EffSS} - Adj_{IdleLosses} - Adj_{Tankless}$$

Eq. 7B.17

Where:

$Adj_{AFUE\text{-}EffSS}$ = factor that adjusts AFUE to steady state efficiency (Eff_{SS}). Varies depending on the product class and the product type (condensing vs. non-condensing). Based on reduced data set for boilers determined in appendix 7d (see parameter *a* values in Eq. 7B.6)
$Adj_{IdleLosses}$ = factor that adjusts idle losses measured when the water heater is placed in unconditioned settings (assumed to vary from 2.4% to 7.2% for high mass boilers and 0.24% to 0.72% for low mass boilers; DOE assumed that 90 percent of condensing boilers and 10 percent of non-condensing boilers are low-mass.), and
$Adj_{Tankless}$ = adjustment factor for tankless coil water heaters[q] (assumed to be 4.5 percent for non-condensing boilers and half of this for condensing boilers).[28]

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[q] RECS 2009 identifies whether a household uses a tankless water heater. DOE uses this to estimate the fraction of tankless coil units. Based on this, DOE estimated that 3 percent of gas boilers and 49 percent of oil boilers that use the boiler for water heating are assumed to have a tankless coil for water heating.

7B.3.1 Determination of Water Heating Load Estimates for Boilers

To calculate the water heating energy use, DOE used the annual water heating load (*WHL*) and AFUE of the selected efficiency level. The *WHL* is the total amount of heat output from the boiler that the house or building water heating needs. The WHL is determined from the annual water heating energy use reported in RECS 2009 and CBECS 2003 for each of the sampled buildings.

DOE used the following equation to calculate the water heating load (WHL):

$$WHL = Q_{YR,HW} \times (AFUE_{ex} - Adj_{FactorWH})$$

Eq. 7B.18

Where:

$Q_{YR,HW}$ = annual fuel consumption for water heating based on RECS 2009 or CBECS 2003 (kBtu/yr),
$AFUE_{ex}$ = AFUE of the existing boiler (see section 7B.2.4), and
$Adj_{FactorWH}$ = as defined in Eq. 7B.16.

Table 7B.3.2 shows the original RECS 2009 and CBECS 2003 water heating energy use for the sampled households and buildings where the boiler is used for water heating (see Table 7B.3.1 for the fraction of boilers that are used for water heating by product class).

Table 7B.3.2 Range of Original Water Heating Energy Use for Each Boiler Product Class, MMBtu/year

Product Class	Min	Max	Average	Percentiles				
				5%	25%	50%	75%	95%
Gas-Fired Hot Water Boilers	2.5	812.7	29.1	8.4	16.8	25.9	35.2	53.6
Gas-Fired Steam Boilers	2.5	99.7	27.2	7.3	18.3	26.7	36.1	50.0
Oil-Fired Hot Water Boilers	4.4	366.2	20.4	7.0	12.3	16.8	23.6	42.4
Oil-Fired Steam Boilers	4.4	210.9	21.0	7.4	13.9	18.1	25.7	43.5
Electric Hot Water Boiler	4.5	636.9	31.0	6.5	10.4	13.4	34.5	36.7
Electric Steam Boiler	4.5	323.3	27.7	5.0	13.4	25.9	36.7	36.7

Table 7B.3.3 shows the results for the range in adjusted water heating load among sample households and buildings where the boiler is used for water heating.

Table 7B.3.3 Range of Adjusted Water Heating Load for Each Boiler Product Class, MMBtu/year

Product Class	Min	Max	Average	Percentiles				
				5%	25%	50%	75%	95%
Gas-Fired Hot Water Boilers	0.1	653.7	19.4	3.1	9.8	16.9	23.6	39.4
Gas-Fired Steam Boilers	0.1	70.5	17.5	2.4	10.2	16.7	22.8	32.9
Oil-Fired Hot Water Boilers	0.1	312.9	14.7	2.3	7.7	12.7	17.4	33.5
Oil-Fired Steam Boilers	0.1	146.1	15.3	4.1	10.3	13.2	18.6	34.0
Electric Hot Water Boiler	0.1	629.4	26.3	2.1	5.9	8.8	29.6	31.6
Electric Steam Boiler	0.1	313.8	22.9	0.7	8.8	21.1	31.6	31.6

7B.4 DETERMINATION OF ANNUAL ELECTRICAL ENERGY CONSUMPTION

The Department calculated boiler electricity consumption for the circulating pump, the draft inducer, and the ignitor.[r] The circulating pump moves water through the house whenever the boiler burner is on (adjusted for delay times between burner and pump operation). In instances where the boiler also serves the home's or building's water heating load, the circulating pump also operates in the cooling season (summer) if there is a call for water heating. In the case of modulating condensing boilers, to accommodate for lower firing rates, the inducer will provide lower combustion airflow to regulate the excess air in the combustion process. DOE assumed that modulating condensing boilers are equipped with an inducer fan with a permanent split capacitor (PSC) motor and two-stage controls. Low-fire operation corresponds to a firing input rate of 90 percent or less of the full input capacity. The inducer is assumed to run at 70-percent airflow rate when the modulating unit operates at low-fire.

DOE also took into account the electricity consumption of such auxiliary equipment as condensate pumps and heat tape, which are sometimes installed with higher efficiency boilers. Additionally, DOE accounted for the additional cooling load due to heat loss from the boiler and water heater as a result of water heating during the cooling season. DOE determined the type of water heater, water heating load, burner operating hours during the summer, and air conditioner (AC) type and efficiency for each household from RECS 2009 and CBECS 2003. DOE then calculated the heat loss from the boiler and the water heater and the subsequent increase in AC electricity use.

The average annual auxiliary electrical energy consumption is calculated in appendix C section 3 of ASHRAE 103-2007:

[r] The DOE and ASHRAE test procedures do not consider the electricity used by controls when the boiler is not firing.

$$E_{AE} = BOH_{SS}\ (y_P * PE + y_{IG} * PE_{IG} + y * BE)$$, for single-stage boilers,

and

$$E_{AE} = BOH_R\ (y_{P,R} * PE_R + y_{IG,R} * PE_{IG,R} + y_R * BE_R) + BOH_{H\ or\ M}\ (y_P * PE_H + y_{IG} * PE_{IG,H} + y * BE_H)$$[s2], for two-stage and continuous modulating boilers

Eq. 7B.19

Where:

$BOHss$ = as defined in Eq. 7B.2,
BOH_H = as defined in Eq. 7B.2,
BOH_M = as defined in Eq. 7B.2,
BOH_R = as defined in Eq. 7B.2,
y_P = as defined in Eq. 7B.3,
$y_{P,R}$ = as defined in Eq. 7B.3,
PE = as defined in Eq. 7B.3,
PE_R = as defined in Eq. 7B.3,
PE_H = as defined in Eq. 7B.3,
y_{IG} = as defined in Eq. 7B.3,
$y_{IG,R}$ = as defined in Eq. 7B.3,
PE_{IG} = as defined in Eq. 7B.3,
$PE_{IG,R}$ = as defined in Eq. 7B.3,
$PE_{IG,H}$ = as defined in Eq. 7B.3,
y = as defined in Eq. 7B.3,
y_R = as defined in Eq. 7B.3,
BE = as defined in Eq. 7B.3,
BE_R = as defined in Eq. 7B.3, and
BE_H = as defined in Eq. 7B.3.

DOE expanded this equation to include the electricity use during water heating, the standby electricity use, and additional electricity use related to the air conditioner:

$$ElecUse_{TOTAL} = \left(BOH_{SH,i} + BOH_{WH}\right) \times ElecPower + ElecUse_{Stby} + ElecUse_{AC}$$

Eq. 7B.20

$BOH_{SH,i}$ = BOH_{SS}, BOH_H, BOH_R, or BOH_M depending on operating mode, as defined in Eq. 7B.5,
BOH_{WH} = water heating burner operating hours (hr/yr), as defined in Eq. 7B.21,
$ElecPower$ = power of multiple electrical components as described in Eq. 7B.19 as well as other secondary components such as a condensate pump required during boiler operation, (kW)

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[s] The ASHRAE test procedure does not deal with ignitor energy consumption. The ratio of ignitor on-time to burner on-time and the ignitor power consumption variables come from the DOE test procedure.[1]

$ElecUse_{Stby}$ = energy consumption during standby (kWh), (see chapter 7) and
$ElecUse_{AC}$ = additional cooling energy consumption during non-heating season due to boiler operation for water heating loads (when applicable) (kWh) (see section 7B.4.1.1).

DOE calculated water heating burner operating hours (BOH_{WH}) as:

$$BOH_{WH} = \frac{WHL}{Q_{IN} \times (AFUE - Adj_{FactorWH})}$$

Eq. 7B.21

Where:

WHL = defined in Eq. 7B.18,
Q_{IN} = defined in Eq. 7B.2,
$AFUE$ = AFUE of the selected efficiency level, and,
$Adj_{FactorWH}$ = defined in Eq. 7B.16.

During manufacturer interviews conducted for the engineering analysis (see chapter 5), manufacturers reported that the majority of their units are shipped with a pump. The most common pump for residential applications is the Taco 007, which uses approximately 80 watts and is used on boiler capacities ranging from 45,000 to 140,000 Btu/h. For this analysis, DOE assumed that non-condensing and condensing units use the same pump motor type, which on average uses 80 watts.

DOE assumed that all condensing hot water boilers have an internal pump that circulate water through the heat exchanger, known as a boiler pump. The engineering analysis determined that the most commonly used boiler pumps are the Taco 0015 or Grundfos UPS 15, which use 120 watts. DOE used this value for all boiler pumps.

DOE is aware that some consumers use circulator pumps and boiler pumps with an electronically commutated motor (ECM) that allows for variable speed operation. DOE assumed that 50 percent of condensing hot water boilers use ECMs for both the circulator pump and the boiler pump, which consume half of the energy that PSC motors consume.

DOE calculated the ratio of pump on-time to burner on-time y and y_R using t^+ (pump on-delay) and t^- (pump off-delay). Manufacturers commented that the on-cycle times of the draft inducer vary considerably. For example, high efficiency products and copper products have a shut-down time delay of up to 30 seconds to protect the heat exchanger from overheating. For this analysis, DOE assumed the shut-down time delay t^+ = 0.5 min and the start-up time delay t^- = 0 min, based on stakeholder comments and boiler model data.

DOE assumed that the inducer motor is a PSC motor, which is mostly used in non-condensing models. Stakeholders commented that condensing products are forced-draft and use an ECM in their draft inducers. To assess the inducer power consumption (PE_H), DOE derived

average values, which reflect different motor types, from the models in the 2015 AHRI directory, as shown in Table 7B.4.1. DOE assumed that all oil-fired boilers are equipped with burner fans.

Table 7B.4.1 Inducer Motor Power Consumption by Product Type

Boiler Type	Gas-Fired Hot Water Boiler	Gas-Fired Steam Boiler	Oil-Fired Hot Water Boiler	Oil-Fired Steam Boiler
Non-Condensing (natural draft)	92	84	-	-
Non-Condensing (induced draft)	163	274	177	232
Condensing	93	-	128	-

For modulating and two-stage condensing gas-fired hot water boilers, DOE assumed that the reduced inducer power (PE_R) would be 70 percent of the PE_H values indicated in Table 7B.4.1. The ratio of draft inducer on-time to burner on-time y_P and $y_{P,R}$ were calculated using t_P (post-purge time). The induced- and forced-draft fans typically operate during post-purge, as well as during the burner on-cycle. In general, the post-purge time can range from 0 to 30 seconds. For this analysis, DOE used a draft inducer post-purge time (t_P) of 30 seconds based on stakeholder input.

Based on manufacturer input, boilers utilize direct spark ignition or hot surface ignition, . DOE assumed direct spark ignition for all products with PE_{IG} equal to 25 watts and t_{IG} equal to 5 seconds.

Some higher-efficiency installations require the use of auxiliary equipment such as a condensate pump. If a household required a condensate pump, DOE assumed that it consumed 60 watts and operated at the same time as the burner. Details of how DOE determined whether a household required a condensate pump can be found in appendix 8C.

7B.4.1.1 Impact of Summer Water Heating on Home Cooling Load

Boilers installed in conditioned spaces that are used for water heating increase the summer cooling load because of convective and radiative heat losses from the boiler and water heater tank to the conditioned space. DOE accounted for the increased electricity use of the air conditioner (AC) resulting from water heating operations during the summer.

From RECS 2009 or CBECS 2003 data, DOE determined the type of water heater and annual water heating energy use for each household or building. DOE assumed that indirect water heaters have a heat loss rate of 0.5 kBtu/h, while other types of water heaters do not lose any heat because they do not store significant amounts of water. Because boilers operate intermittently unlike water heaters, which must keep water heated at all times, DOE assumed that high-mass boilers have a heat loss rate that is half that of the water heater, while low-mass boilers have a heat loss rate that is ten percent that of high-mass boilers, or five percent that of the water heater. From the characteristics of each household's boiler and water heater and the

water heater burner operating hours during the summer, DOE estimated the heat losses from water heating from both the water heater and the boiler during the cooling season. Table 7B.4.2 and Table 7B.4.3 show DOE's assumptions for calculating water heater and boiler heat losses that contribute to an increased cooling load.

Table 7B.4.2 Water Heater Heat Loss During the Cooling Season

Water Heater Type	Water Heater Heat Loss Rate *kBtu/h*
Indirect	0.5
Other	0

Table 7B.4.3 Boiler Heat Loss During the Cooling Season

Boiler Type	Boiler Heat Loss Rate
High Mass	5% of WH loss
Low Mass	50% of WH loss

DOE then determined the type of air conditioner (no AC, electric heat pump, central AC, or room AC) and the efficiency of the air conditioner based on *AEO 2015* Stock Efficiencies in 2021[4] for each household from RECS 2009 or CBECS 2003. Based on the air conditioner efficiency, DOE calculated the increase in cooling electricity use as a result of heat gain from water heating.

7B.4.1.2 Example of Breakdown of Electricity Use Results

Table 7B.4.4 provides an example of the breakdown of the electricity use by operation mode for hot water gas-fired boilers at the baseline efficiency level (82 percent-AFUE) and at the 90 percent-AFUE efficiency level. Table 7B.4.4 shows the fraction of installations impacted by each electricity use operation mode and the average electricity use for installations impacted by the electricity use operation mode. The total electricity use reported in the last row is then the sum product of the fraction and corresponding average electricity use.

Table 7B.4.4 Breakdown of Electricity Use by Operation Mode for Hot Water Gas-fired Boilers at Baseline and Condensing Efficiency Levels

Electricity Use by Operation Mode	HWGB at 82% AFUE (EL 0)		HWGB at 90% AFUE (EL 4)	
	Fraction	kW/year	Fraction	kW/year
Space Heating	100%	124	100%	240
Water Heating	41%	43	41%	48
Standby	100%	52	100%	51
AC Use Differential	21%	22	21%	-19
Condensate Pump	0%	0	22%	93
Total Electricity Use		198		328

7B.5 SUMMARY OF FUEL ENERGY CONSUMPTION RESULTS

Table 7B.5.1 provides an example of the breakdown of the space heating and water heating energy use by operation mode for each product class and efficiency level.

Table 7B.5.1 Average Annual Space Heating and Water Heating Consumption for Residential Boilers for AFUE Standard

EL	Design Option	Annual Fuel Use			
		Space Heating *MMBtu/yr*	Water Heating *MMBtu/yr*	Total *kWh/yr*	Savings *kWh/yr*
Gas-fired Hot Water Boiler					
0	82% AFUE - Baseline	74.3	11.6	85.9	-
1	83% AFUE – Increased HX Area	73.4	11.5	84.8	1.0
2	84% AFUE – Increased HX Area	72.5	11.3	83.8	2.1
3	85% AFUE – Increased HX Area	71.4	11.2	82.6	3.3
4	90% AFUE – Condensing Baseline	64.7	10.6	75.3	10.5
5	92% AFUE – Increased HX Area	63.4	10.4	73.8	12.1
6	96% AFUE – Max Tech	60.8	10.0	70.8	15.1
Gas-fired Steam Boiler					
0	80% AFUE - Baseline	79.1	1.2	80.3	-
1	82% AFUE – Increased HX Area	77.1	1.2	78.3	2.1
2	83% AFUE – Max Tech	76.1	1.2	77.2	3.1
Oil-fired Hot Water Boiler					
0	84% AFUE - Baseline	73.1	7.2	80.3	-
1	85% AFUE – Increased HX Area	72.2	7.2	79.3	1.0
2	86% AFUE – Increased HX Area	71.0	7.1	78.0	2.3
3	91% AFUE – Max Tech	66.4	6.6	73.0	7.3
Oil-fired Steam Boiler					
0	82% AFUE - Baseline	76.3	1.9	78.3	-
1	84% AFUE – Increased HX Area	74.4	1.9	76.3	1.9
2	85% AFUE – Increased HX Area	73.5	1.9	75.4	2.9
3	86% AFUE – Max Tech	72.3	1.8	74.1	4.1

The RECS 2009 national average annual space heating energy consumption of 51.4 MMBtu/yr for housing units using natural gas of and 70.3 MMBtu/yr for housing units using fuel oil. The primary reasons for the differences between the national RECS result and DOE's estimates are: (1) DOE's analysis recognizes that the boilers are mostly installed in colder climates, and (2) DOE accounts for residential boilers in commercial buildings. Since boilers are mostly installed in colder climates, the average energy use of boilers is significantly higher than the average space heating national energy use. Based on 2008-2012 AHRI shipments data by State and RECS 2009 households, almost 70 percent of gas-fired boilers and 90 percent of oil-fired boilers are installed in the Northeast. In 2009, based on RECS 2009 and 2008-2012 AHRI

shipments data, the average annual space heating energy consumption is 75.8 MMBtu/yr for housing units with gas-fired hot water boilers. In DOE's analysis, as explained in this appendix, these numbers are adjusted to take into account: 2008-2012 AHRI shipments data by State, typical heating degree days (HDD) for an average year, HDD trends, building shell efficiency, number of boilers per household or building, automatic means, and secondary heating equipment. Based on these adjustments, DOE estimated that the average annual shipment-weighted space heating energy use is 56.7 MMBtu/yr for gas-fired hot water boilers in residential applications and 205.9 MMBtu/yr in commercial applications in 2021 (or 68.6 MMBtu/yr for both residential and commercial buildings) taking into account the base case efficiency distributions presented in chapter 8. For gas-fired hot water boilers, the 2021 estimates are about 30 percent lower than the estimated values in RECS 2009 or CBECS 2003. The results for the other boiler product classes are similar.

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APPENDIX 7C. MAPPING OF WEATHER STATION DATA TO RECS AND CBECS BUILDINGS

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APPENDIX 7C. MAPPING OF WEATHER STATION DATA TO RECS AND CBECS BUILDINGS

7C.1 INTRODUCTION

The Energy Information Administration's (EIA) 2009 Residential Energy Consumption Survey (RECS 2009)[1] and EIA's 2003 Commercial Building Energy Consumption Survey (CBECS 2003)[2] provide annual data on heating and cooling degree-days but not on other weather parameters needed for the analysis such as heating and cooling outdoor design temperature (ODT), monthly heating degree days (HDD) and monthly cooling degree days (CDD), and average outdoor temperature. ODTs are used for sizing residential boiler products as described in appendix 7B. Energy price data used in this analysis are available on a monthly basis. Monthly HDD are used to disaggregate the annual energy use provided by RECS and CBECS by month. Monthly energy use is combined with monthly energy prices to find the monthly operating cost (see appendix 7B and appendix 8D).

7C.2 MAPPING METHODOLOGY

To derive the additional weather data that is needed for the analysis (*e.g.*, ODT, monthly HDD), for each building in the sample, DOE developed an approach to assign a physical location to each RECS household and CBECS building. [a] The methodology consists of the following steps:

1. DOE assembled monthly weather data from 360 weather stations from the National Oceanic and Atmospheric Administration (NOAA) that provide the heating and cooling degree-days at base temperature 65ºF for year 2009 (for the RECS sample) and year 2003 (for the CBECS sample), for these weather stations.[3] The 2009 and 2003 heating and cooling degree days match the period used to determine the degree-days in RECS 2009 and in CBECS 2003, respectively.
2. DOE gathered ODT data from the 1993 ASHRAE Handbook and only selected the weather stations for which NOAA provided HDD and CDD, which reduced the number of weather stations used in the matching process to 339.[4]
3. RECS and CBECS report both HDD and CDD to base temperature 65ºF for each building record. DOE assigned each building to one of the 339 weather stations by calculating which weather station (within the appropriate region) was the closest using the best linear least squares fit of the RECS/CBECS data to the weather data. Eq. 7C.1 calculates the U.S. weather station closest (or with minimum "distance") to the RECS/CBECS building:

$$\text{"}Distance\text{"} = \sqrt{(HDD_2 - HDD_1)^2 + (CDD_2 - CDD_1)^2}$$

Eq. 7C.1

[a] For confidentiality, heating and cooling degree day values were altered slightly by EIA to mask the exact geographic location of the housing unit.

Where:

HDD_1 = heating degree days from U.S. weather data,
HDD_2 = heating degree days from RECS/CBECS data,
CDD_1 = cooling degree days from U.S. weather data, and
CDD_2 = cooling degree days from RECS/CBECS data.

7C.3 MAPPING RESULTS

Table 7C.3.1 shows the imputation results for all RECS and CBECS locations. Note that some U.S. weather station data match with several of the RECS/CBECS weather data. The number of RECS/CBECS buildings that were matched to the specified weather station is indicated in the column "Count." Table 7C.3.1 shows the data matches (321 weather stations) including the heating and cooling ODT as well as annual average outdoor temperature for the weather stations.[b]

Table 7C.3.1 Weather Station Mapping Statistics, Heating and Cooling ODT, and Average Outdoor Temperature

Station Location			Heating	Cooling	CBECS 2003	CBECS 2003	RECS 2009	RECS 2009	Average Outdoor Temp
Code	State	City	ODT	ODT	HDD	CDD	HDD	CDD	ºF
ABE	PA	ALLENTOWN	9.0	88	5935	797	5725	622	50.6
ABI	TX	ABILENE	20.0	97	2366	2374	2359	2494	64.4
ABQ	NM	ALBUQUERQUE	16.0	93	3663	1678	3823	1435	56.8
ABR	SD	ABERDEEN	-15.0	91	8324	605	8872	329	43.8
ABY	GA	ALBANY	29.0	95	1927	2413	1767	2686	66.3
ACT	TX	WACO	26.0	99	1975	2776	1927	3086	66.6
ACY	NJ	ATLANTIC CITY	13.0	89	5328	1012	4693	994	53.5
ADQ	AK	KODIAK	13.0	65	8051	15	8903	0	40.5
AGS	GA	AUGUSTA	23.0	95	2561	1820	2475	2068	63.2
AHN	GA	ATHENS	22.0	93	2831	1564	2882	1903	61.5
AKN	AK	KING SALMON	-19.0	67	9773	10	11088	0	34.5
ALB	NY	ALBANY	-1.0	86	7023	613	6644	433	47.5
ALI	TX	ALICE	34.0	99	1022	3628	738	4832	72.3
ALO	IA	WATERLOO	-10.0	89	6962	849	7253	448	47.2
ALS	CO	ALAMOSA	-16.0	82	7762	151	8229	49	40.8
ALW	WA	WALLA WALLA	7.0	95	4498	1189	5062	1144	54.2
AMA	TX	AMARILLO	11.0	95	3787	1410	4034	1340	57.0
ANC	AK	ANCHORAGE	-18.0	68	9300	25	10335	2	36.2
ANJ	MI	SAULT ST MARIE	-8.0	80	8809	168	8878	119	40.1
AOO	PA	ALTOONA	5.0	86	6515	439	6109	433	49.8
APN	MI	ALPENA	-6.0	84	8468	241	8343	161	42.5
ART	NY	WATERTOWN	-6.0	83	8018	379	7707	298	45.7
AST	OR	ASTORIA	29.0	72	4517	22	4871	39	51.0
ATL	GA	ATLANTA	22.0	92	2732	1614	2813	1838	62.1
AUG	ME	AUGUSTA	-3.0	84	7746	420	7487	276	45.7
AUS	TX	AUSTIN	28.0	96	1888	2793	1722	3214	69.0

[b] The names of weather stations MQT, SSI, and SSM changed to SAW, BQK, and ANJ, respectively.

Station Location			Heating	Cooling	CBECS 2003	CBECS 2003	RECS 2009	RECS 2009	Average Outdoor Temp
Code	State	City	ODT	ODT	HDD	CDD	HDD	CDD	ºF
AUW	WI	WAUSAU	-12.0	85	8299	466	8337	277	44.4
AVL	NC	ASHEVILLE	14.0	86	4207	718	4194	768	54.8
AXN	MN	ALEXANDRIA	-16.0	86	8675	553	8922	340	41.8
AYS	GA	WAYCROSS	29.0	94	1424	2689	1494	3059	66.7
BDL	CT	HARTFORD	7.0	88	6359	723	6072	610	50.2
BDR	CT	BRIDGEPORT	9.0	85	5800	824	5484	669	52.1
BET	AK	BETHEL	-24.0	68	11261	14	12530	0	29.9
BFD	PA	BRADFORD	-1.0	80	8029	125	8059	74	49.8
BFF	NE	SCOTTSBLUFF	-3.0	92	6293	867	6689	579	47.8
BFL	CA	BAKERSFIELD	32.0	101	1931	2692	1873	2644	65.0
BGM	NY	BINGHAMTON	1.0	82	7580	316	7067	261	45.8
BGR	ME	BANGOR	-6.0	84	8161	403	8098	246	45.7
BHM	AL	BIRMINGHAM	21.0	93	2664	1874	2605	1958	62.2
BIL	MT	BILLINGS	-10.0	90	6623	1017	6948	627	47.4
BIS	ND	BISMARCK	-19.0	90	8505	738	9130	332	42.3
BKE	OR	BAKER	6.0	91	6650	315	7529	220	45.4
BKW	WV	BECKLEY	4.0	84	5439	487	5325	404	51.6
BLH	CA	BLYTHE	33.0	112	853	4649	968	4580	71.3
BLI	WA	BELLINGHAM	15.0	76	5124	54	5568	115	50.8
BNA	TN	NASHVILLE	14.0	92	3595	1449	3615	1558	58.9
BOI	ID	BOISE	10.0	95	4877	1316	5592	1199	51.9
BOS	MA	BOSTON	9.0	87	6067	745	5694	581	51.6
BQK	GA	BRUNSWICK	32.0	91	1557	2513	1313	3320	68.6
BRL	IA	BURLINGTON	-3.0	91	6031	870	5687	810	50.0
BRO	TX	BROWNSVILLE	39.0	94	587	4025	525	4300	73.3
BTM	MT	BUTTE	-17.0	84	8967	180	9212	45	39.7
BTR	LA	BATON ROUGE	29.0	93	1683	2674	1404	2985	67.0
BTV	VT	BURLINGTON	-7.0	85	7833	576	7413	392	45.2
BUF	NY	BUFFALO	6.0	84	6909	429	6651	361	47.9
BWG	KY	BOWLING GREEN	10.0	91	4087	1183	3808	1407	57.2
BWI	MD	BALTIMORE	13.0	91	5010	1020	4745	1088	54.6
BYI	ID	BURLEY	2.0	90	5978	568	6697	397	46.5
CAE	SC	COLUMBIA	24.0	94	2562	1908	2561	2220	63.6
CAK	OH	AKRON CANTON	6.0	86	6361	543	6131	497	49.5
CAO	NM	CLAYTON	9.0	91	4390	1025	4517	1143	53.3
CAR	ME	CARIBOU	-13.0	82	9754	214	9415	149	39.2
CDB	AK	COLD BAY	10.0	57	8693	0	9668	0	38.4
CDC	UT	CEDAR CITY	5.0	91	5606	810	6058	645	52.0
CDV	AK	CORDOVA	1.0	67	8332	0	9511	0	38.4
CHA	TN	CHATTANOOGA	18.0	92	3206	1498	3168	1808	60.0
CHS	SC	CHARLESTON	27.0	93	1981	2272	1941	2390	65.3
CID	IA	CEDAR RAPIDS	-5.0	89	6861	721	6977	419	47.2
CLE	OH	CLEVELAND	5.0	87	6077	685	5833	664	49.6
CLL	TX	COLLEGE STATIO	29.0	96	1662	2965	1404	3476	69.0
CLT	NC	CHARLOTTE	22.0	91	3311	1308	3346	1611	61.4
CMH	OH	COLUMBUS	5.0	89	5504	765	5243	874	52.9
CNK	KS	CONCORDIA	3.0	96	5231	1465	5558	1094	53.5
CNM	NM	CARLSBAD	19.0	98	2322	2370	2398	2376	62.8
COD	WY	CODY	-13.0	87	6992	686	7551	410	44.9
CON	NH	CONCORD	-3.0	87	7666	541	7462	325	45.9

Station Location			Heating	Cooling	CBECS 2003	CBECS 2003	RECS 2009	RECS 2009	Average Outdoor Temp
Code	State	City	ODT	ODT	HDD	CDD	HDD	CDD	ºF
COS	CO	COLORADO SPRIN	2.0	88	5846	603	6301	356	47.8
COU	MO	COLUMBIA	4.0	92	5010	1151	4999	958	54.0
CPR	WY	CASPER	-5.0	91	7192	587	7858	225	44.9
CRP	TX	CORPUS CHRISTI	35.0	94	968	3462	811	4058	71.5
CRW	WV	CHARLESTON	11.0	88	4628	789	4443	960	54.5
CSG	GA	COLUMBUS	24.0	94	2053	2284	2183	2194	65.1
CSV	TN	CROSSVILLE	15.0	87	4240	839	4100	940	54.5
CTB	MT	CUT BANK	-20.0	84	8419	313	8687	139	39.7
CVG	OH	CINCINNATI	6.0	90	5229	838	4950	874	54.2
CXY	PA	HARRISBURG	11.0	90	5534	856	5097	866	53.3
CYS	WY	CHEYENNE	-1.0	86	6680	577	7390	203	44.9
DAB	FL	DAYTONA BEACH	35.0	91	849	3153	753	3321	71.0
DAY	OH	DAYTON	4.0	88	5832	676	5602	732	51.5
DBQ	IA	DUBUQUE	-7.0	86	7189	602	7204	345	46.9
DCA	DC	WASHINGTON	17.0	93	4338	1288	4124	1427	57.5
DDC	KS	DODGE CITY	5.0	97	4926	1490	4975	1257	55.2
DEN	CO	DENVER	1.0	92	5796	800	5988	541	50.1
DFW	TX	DALLAS FT WORT	22.0	98	2239	2752	2097	2745	65.5
DLH	MN	DULUTH	-16.0	81	9526	265	9517	118	39.1
DRT	TX	DEL RIO	31.0	98	1338	3406	1252	3807	69.7
DSM	IA	DES MOINES	-5.0	90	6263	1130	6124	898	50.0
DTW	MI	DETROIT	6.0	87	6398	659	6224	588	49.7
DUG	AZ	DOUGLAS	31.0	98	2340	2206	2160	2204	61.5
DUJ	PA	DU BOIS	5.0	84	7092	243	6753	254	49.8
EAU	WI	EAU CLAIRE	-11.0	87	7949	623	8208	333	44.4
EGE	CO	EAGLE	-7.0	86	6889	369	7593	124	40.8
EKA	CA	EUREKA	33.0	65	4670	12	5137	2	52.9
EKN	WV	ELKINS	6.0	83	6291	322	5993	284	49.8
EKO	NV	ELKO	-2.0	92	6266	597	6948	450	46.4
ELP	TX	EL PASO	24.0	98	2207	2696	2106	2783	64.7
ELY	NV	ELY	-4.0	87	6856	404	7925	125	44.8
ENA	AK	KENAI	-14.0	65	9819	3	10423	0	36.2
ERI	PA	ERIE	9.0	84	6496	489	6183	423	50.0
EUG	OR	EUGENE	22.0	88	4269	350	4999	331	52.1
EVV	IN	EVANSVILLE	9.0	92	4530	1143	4397	1283	56.0
EWN	NC	NEW BERN	24.0	92	2797	1818	2769	1788	63.8
EWR	NJ	NEWARK	14.0	91	5165	1098	4790	1021	54.5
EYW	FL	KEY WEST	57.0	89	127	5071	108	5017	78.1
FAR	ND	FARGO	-18.0	88	8862	616	9304	362	41.5
FAT	CA	FRESNO	30.0	101	2147	2412	2239	2390	63.2
FCA	MT	KALISPELL	-7.0	86	7681	317	5729	1492	42.6
FDY	OH	FINDLAY	3.0	87	6156	643	5901	698	50.2
FLG	AZ	FLAGSTAFF	4.0	83	6326	193	6741	176	46.2
FLL	FL	FT LAUDERDALE	46.0	91	194	4622	118	4839	75.4
FLO	SC	FLORENCE	25.0	94	2644	1839	2541	2061	63.6
FMY	FL	FORT MYERS	44.0	93	370	4062	294	4151	74.9
FNT	MI	FLINT	1.0	86	6891	494	7068	328	46.8
FSD	SD	SIOUX FALLS	-11.0	90	7463	724	7670	481	45.1
FSM	AR	FORT SMITH	17.0	96	3144	1998	3174	1906	61.2
FWA	IN	FORT WAYNE	1.0	88	6481	576	6077	601	49.9

Station Location			Heating	Cooling	CBECS 2003	CBECS 2003	RECS 2009	RECS 2009	Average Outdoor Temp
Code	State	City	ODT	ODT	HDD	CDD	HDD	CDD	ºF
FYV	AR	FAYETTEVILLE	12.0	93	4017	1202	3957	1185	57.7
GCK	KS	GARDEN CITY	4.0	97	5025	1367	5014	1154	55.2
GEG	WA	SPOKANE	2.0	89	6295	592	6942	599	47.3
GFK	ND	GRAND FORKS	-22.0	89	9575	417	9928	269	40.3
GFL	NY	GLENS FALLS	-5.0	85	8024	376	7612	285	45.7
GLD	KS	GOODLAND	0.0	94	5494	1096	6016	722	50.7
GLS	TX	GALVESTON	36.0	91	1058	3343	907	3640	71.2
GNV	FL	GAINESVILLE	31.0	92	1288	2700	1181	2789	68.6
GRB	WI	GREEN BAY	-9.0	85	7878	386	8005	275	44.4
GRI	NE	GRAND ISLAND	-3.0	93	5942	1059	6431	788	49.9
GRR	MI	GRAND RAPIDS	5.0	86	7030	487	6580	444	47.6
GSO	NC	GREENSBORO	18.0	90	3622	1210	3605	1510	58.1
GSP	SC	GREENVILLE	22.0	91	3108	1379	3116	1735	60.0
GTF	MT	GREAT FALLS	-15.0	89	7431	576	7941	300	43.7
GUP	NM	GALLUP	5.0	87	5827	550	6134	442	53.3
GWO	MS	GREENWOOD	20.0	94	2668	2080	2376	2250	61.3
HAT	NC	CAPE HATTERAS	29.0	86	2446	1687	1308	3750	62.8
HBR	OK	HOBART	16.0	101	3439	2129	3392	2034	59.8
HIB	MN	HIBBING	-20.0	81	10000	203	10159	64	37.4
HKY	NC	HICKORY	18.0	90	3703	1032	3593	1353	58.1
HLN	MT	HELENA	-16.0	87	7066	798	7704	444	44.0
HNL	HI	HONOLULU-OAHU	63.0	89	0	5030	0	4816	77.5
HOM	AK	HOMER	4.0	62	8686	0	9817	0	38.1
HON	SD	HURON	-14.0	91	7598	860	8070	469	45.3
HSV	AL	HUNTSVILLE	16.0	92	3121	1633	2982	1863	60.6
HTL	MI	HOUGHTON LAKE	1.0	85	8311	197	8329	162	43.1
HTS	WV	HUNTINGTON	10.0	89	4487	881	4557	922	55.0
HUL	ME	HOULTON	-13.0	85	9458	238	9316	178	39.9
HVR	MT	HAVRE	-11.0	90	8190	683	8844	327	43.7
IAH	TX	HOUSTON	32.0	96	1386	3185	1267	3410	68.8
ICT	KS	WICHITA	7.0	97	4502	1620	4552	1506	56.4
IDA	ID	IDAHO FALLS	-6.0	89	7069	409	7936	239	46.5
ILG	DE	WILMINGTON	14.0	89	5206	1010	4789	1031	54.4
ILM	NC	WILMINGTON	26.0	91	2625	1864	2521	1937	63.8
IND	IN	INDIANAPOLIS	2.0	89	5551	883	5203	953	52.5
INL	MN	INT'L FALLS	-25.0	83	10115	220	10648	72	37.4
INW	AZ	WINSLOW	10.0	93	4377	1459	4233	1395	55.2
IPT	PA	WILLIAMSPORT	7.0	87	6233	611	5636	644	49.8
ISN	ND	WILLISTON	-21.0	92	9603	670	9721	297	40.9
ITO	HI	HILO-HAWAII	62.0	85	0	3669	0	3050	73.9
JAX	FL	JACKSONVILLE	32.0	93	1450	2605	1339	2772	68.0
JKL	KY	JACKSON	14.0	87	4299	917	4237	984	55.9
JLN	MO	JOPLIN	10.0	94	3974	1677	4216	1382	56.2
JNU	AK	JUNEAU	1.0	70	8198	2	8536	6	41.5
JXN	MI	JACKSON	5.0	86	6955	392	6585	420	47.1
KTN	AK	KETCHIKAN	20.0	68	7160	0	7359	68	38.3
LAF	IN	WEST LAFAYETTE	3.0	90	5690	825	5436	826	0.0
LAN	MI	LANSING	1.0	86	7239	385	6830	372	46.8
LAS	NV	LAS VEGAS	28.0	106	1882	3846	1882	3818	68.1
LAX	CA	LOS ANGELES	43.0	80	1237	677	1294	569	63.3

Station Location			Heating	Cooling	CBECS 2003	CBECS 2003	RECS 2009	RECS 2009	Average Outdoor Temp
Code	State	City	ODT	ODT	HDD	CDD	HDD	CDD	ºF
LBB	TX	LUBBOCK	15.0	96	2960	1950	3178	1965	59.7
LBF	NE	NORTH PLATTE	-4.0	92	6249	926	6946	534	48.7
LCH	LA	LAKE CHARLES	31.0	93	1525	2823	1380	2980	67.9
LEB	NH	LEBANON	-3.0	86	8434	362	7312	371	45.9
LEX	KY	LEXINGTON	8.0	89	4750	954	4670	1020	55.2
LFK	TX	LUFKIN	29.0	95	1966	2600	1803	2839	69.0
LFT	LA	LAFAYETTE	30.0	93	1581	2787	1296	3086	68.3
LGA	NY	NEW YORK	15.0	89	5025	1155	4647	1041	55.1
LIH	HI	LIHUE-KAUAI	62.0	85	0	4136	2	3611	75.7
LIT	AR	LITTLE ROCK	20.0	95	3105	2187	2946	1943	62.1
LND	WY	LANDER	-11.0	87	7475	713	7743	351	45.0
LNK	NE	LINCOLN	-2.0	94	6027	1131	6159	912	51.1
LOL	NV	LOVELOCK	12.0	97	5463	975	5302	1189	50.1
LRD	TX	LAREDO	36.0	101	826	4348	602	5330	73.3
LSE	WI	LACROSSE	-9.0	89	7126	854	7334	536	47.3
LWS	ID	LEWISTON	6.0	94	4803	1081	5386	1008	52.4
LWT	MT	LEWISTOWN	-16.0	86	7878	493	8526	183	43.7
LYH	VA	LYNCHBURG	16.0	90	4434	884	4433	1003	55.4
MAF	TX	MIDLAND ODESSA	21.0	98	2366	2509	2495	2445	63.4
MBS	MI	SAGINAW	4.0	87	7313	406	6960	350	47.1
MCB	MS	MCCOMB	26.0	92	1909	2482	1833	2472	64.1
MCI	MO	KANSAS CITY	6.0	93	5053	1419	5084	1093	54.2
MCN	GA	MACON	25.0	94	2261	2195	2288	2133	63.7
MCO	FL	ORLANDO	38.0	93	661	3528	588	3620	72.8
MCW	IA	MASON CITY	-11.0	88	7699	556	7856	338	47.2
MEM	TN	MEMPHIS	18.0	94	2954	1961	2906	2091	62.3
MFD	OH	MANSFIELD	5.0	85	6493	476	6214	468	48.7
MFE	TX	MCALLEN	39.0	99	707	4415	393	5387	73.3
MFR	OR	MEDFORD	23.0	95	4002	1060	4459	1043	54.4
MGM	AL	MONTGOMERY	25.0	94	2248	2212	2137	2367	65.0
MGW	WV	MORGANTOWN	8.0	87	5358	628	4957	836	54.0
MHS	CA	MT SHASTA	21.0	88	5294	418	5474	433	49.2
MIA	FL	MIAMI	47.0	91	166	4721	109	4914	76.7
MKE	WI	MILWAUKEE	-4.0	87	7058	601	6816	474	47.5
MKG	MI	MUSKEGON	6.0	83	6740	516	6719	371	47.1
MKL	TN	JACKSON	16.0	93	3603	1394	3379	1597	59.4
MLB	FL	MELBOURNE	43.0	91	632	3469	526	3718	73.2
MLC	OK	MCALESTER	19.0	96	3082	1973	3136	1845	60.1
MLI	IL	MOLINE	-4.0	91	6207	933	6250	636	50.2
MLS	MT	MILES CITY	-15.0	93	7377	1064	7700	716	46.3
MLU	LA	MONROE	25.0	95	2381	2353	2118	2547	65.7
MOB	AL	MOBILE	29.0	92	1667	2695	1594	2681	66.8
MOT	ND	MINOT	-20.0	89	9066	609	9559	314	41.4
MPV	VT	MONTPELIER	-6.0	83	8793	305	7998	237	45.2
MRB	WV	MARTINSBURG	10.0	91	5411	783	5046	854	54.0
MSL	AL	MUSCLE SHOALS	21.0	93	3138	1533	2948	1773	61.0
MSN	WI	MADISON	-7.0	87	7356	560	7343	368	46.1
MSO	MT	MISSOULA	-6.0	88	7073	518	7588	355	44.8
MSP	MN	MINNEAPOLIS	-12.0	88	7538	880	7613	646	45.4
MSS	NY	MASSENA	-8.0	84	8752	381	7980	298	45.7

Station Location			Heating	Cooling	CBECS 2003	CBECS 2003	RECS 2009	RECS 2009	Average Outdoor Temp
Code	State	City	ODT	ODT	HDD	CDD	HDD	CDD	ºF
MSY	LA	NEW ORLEANS	33.0	92	1327	3162	1156	3221	68.8
NYL	AZ	YUMA	39.0	109	558	4747	671	4757	75.3
OFK	NE	NORFOLK	-4.0	92	6312	962	6789	643	48.7
OGG	HI	KAHULUI-MAUI	61.0	88	0	4270	1	3746	75.8
OKC	OK	OKLAHOMA CITY	13.0	96	3529	1881	3519	1849	60.1
OLM	WA	OLYMPIA	22.0	83	5095	144	5614	178	49.6
OMA	NE	OMAHA	-3.0	90	6130	1158	6288	851	50.7
ORD	IL	CHICAGO	0.0	90	6446	697	6417	585	49.1
ORF	VA	NORFOLK	22.0	91	3279	1761	3330	1659	59.6
ORH	MA	WORCESTER	4.0	83	7006	479	6699	370	47.2
OTM	IA	OTTUMWA	-4.0	92	6335	883	6317	588	50.0
P11	ND	DEVIL'S LAKE	-21.0	87	9544	454	10245	236	40.3
PAH	KY	PADUCAH	12.0	93	4365	1258	4198	1239	56.8
PBI	FL	WEST PALM BEAC	45.0	90	294	4388	239	4314	75.3
PDT	OR	PENDLETON	5.0	93	4739	895	5713	720	52.3
PDX	OR	PORTLAND	23.0	87	3908	623	4357	635	53.5
PHL	PA	PHILADELPHIA	14.0	90	4894	1269	4557	1219	55.3
PHX	AZ	PHOENIX	34.0	108	702	4975	807	4942	74.2
PIA	IL	PEORIA	-4.0	90	5846	906	5841	752	50.8
PIH	ID	POCATELLO	-1.0	91	6443	675	7463	321	46.5
PIR	SD	PIERRE	-10.0	95	7200	961	7738	577	47.5
PIT	PA	PITTSBURGH	5.0	87	5892	587	5661	617	50.9
PKB	WV	PARKERSBURG	11.0	88	5138	729	4910	850	54.0
PNS	FL	PENSACOLA	29.0	92	1565	2642	1443	2729	68.2
PRB	CA	PASO ROBLES	29.0	98	2699	1219	2676	1095	58.5
PUB	CO	PUEBLO	0.0	96	4891	1115	5427	818	51.7
PVD	RI	PROVIDENCE	9.0	86	5961	742	5717	579	51.1
PWM	ME	PORTLAND	-1.0	83	7508	355	7107	294	45.7
RAP	SD	RAPID CITY	-7.0	91	7034	905	7738	362	46.6
RBL	CA	RED BLUFF	32.0	102	2635	2097	2452	2122	61.6
RDD	CA	REDDING	31.0	102	2697	2247	2750	2086	61.6
RDM	OR	REDMOND	9.0	90	6020	353	6737	313	44.2
RDU	NC	RALEIGH DURHAM	20.0	92	3413	1459	3164	1865	59.6
RFD	IL	ROCKFORD	-4.0	89	6738	732	6738	433	47.9
RIC	VA	RICHMOND	17.0	92	3971	1336	3781	1564	57.6
RKS	WY	ROCK SPRINGS	-3.0	84	7574	540	8204	230	42.8
RNO	NV	RENO	10.0	92	4556	1184	4948	1071	51.3
ROA	VA	ROANOKE	16.0	90	4216	1002	3931	1173	56.3
ROC	NY	ROCHESTER	5.0	86	6986	477	6765	315	47.6
ROW	NM	ROSWELL	18.0	96	2678	2063	3098	1961	60.8
RSL	KS	RUSSELL	4.0	96	5157	1459	5298	1194	53.5
RST	MN	ROCHESTER	-12.0	85	7957	512	7884	321	43.4
SAC	CA	SACRAMENTO	32.0	98	2417	1463	2531	1357	61.1
SAN	CA	SAN DIEGO	44.0	81	1060	724	1050	813	64.4
SAT	TX	SAN ANTONIO	30.0	97	1485	3039	1270	3598	68.7
SAV	GA	SAVANNAH	27.0	93	1851	2434	1739	2497	66.2
SAW	MI	MARQUETTE	-8.0	83	9288	248	9379	121	38.7
SBN	IN	SOUTH BEND	1.0	88	6416	626	6426	545	49.5
SBY	MD	SALISBURY	16.0	90	4870	1010	4345	1149	56.6
SCK	CA	STOCKTON	30.0	98	2497	1525	2451	1468	61.8

Station Location			Heating	Cooling	CBECS 2003	CBECS 2003	RECS 2009	RECS 2009	Average Outdoor Temp
Code	State	City	ODT	ODT	HDD	CDD	HDD	CDD	ºF
SDF	KY	LOUISVILLE	10.0	91	4201	1307	4155	1316	56.9
SEA	WA	SEATTLE TACOMA	26.0	81	4509	277	4879	319	52.3
SFO	CA	SAN FRANCISCO	38.0	78	2494	269	2614	220	57.3
SGF	MO	SPRINGFIELD	9.0	92	4529	1321	4596	1114	56.2
SHR	WY	SHERIDAN	-8.0	90	7401	652	7844	287	44.5
SHV	LA	SHREVEPORT	25.0	95	2143	2504	2164	2449	65.7
SIT	AK	SITKA	21.0	64	6515	2	7309	4	41.5
SJT	TX	SAN ANGELO	22.0	97	2180	2497	2020	2814	64.5
SLC	UT	SALT LAKE CITY	8.0	95	5060	1544	5716	1147	52.0
SLE	OR	SALEM	23.0	88	4162	467	4660	457	52.6
SLN	KS	SALINA	5.0	98	4608	1771	5012	1335	56.4
SNP	AK	ST PAUL ISLAND	3.0	52	9790	0	11420	0	35.0
SPI	IL	SPRINGFIELD	2.0	91	5549	916	5234	933	52.7
SPS	TX	WICHITA FALLS	18.0	100	2752	2485	2838	2394	63.1
STC	MN	SAINT CLOUD	-11.0	88	8489	496	8704	301	41.8
STL	MO	SAINT LOUIS	6.0	93	4445	1485	4438	1457	56.3
SUX	IA	SIOUX CITY	-7.0	90	6699	833	6913	678	48.3
SYR	NY	SYRACUSE	2.0	86	6939	522	6687	439	47.4
TAD	CO	TRINIDAD	3.0	90	5109	944	5323	719	51.0
TCL	AL	TUSCALOOSA	23.0	93	2510	2047	2349	2136	64.0
TKA	AK	TALKEETNA	-21.0	73	8824	85	11085	28	33.9
TLH	FL	TALLAHASSEE	30.0	94	1673	2538	1574	2802	68.0
TOL	OH	TOLEDO	1.0	88	6311	630	6283	592	49.5
TOP	KS	TOPEKA	4.0	94	4887	1499	4968	1195	54.3
TPA	FL	TAMPA	40.0	91	639	3666	496	3876	73.1
TPH	NV	TONOPAH	10.0	92	5102	1127	5298	874	51.3
TRI	TN	BRISTOL	14.0	87	4294	860	4267	930	54.9
TUL	OK	TULSA	13.0	97	3473	2053	3608	1885	60.8
TUP	MS	TUPELO	19.0	94	3002	1722	2842	1947	61.3
TUS	AZ	TUCSON	32.0	104	1279	3480	1268	3626	68.7
TVC	MI	TRAVERSE CITY	1.0	86	7826	345	7695	253	47.1
TXK	AR	TEXARKANA	23.0	96	2259	2573	2573	2006	61.2
TYS	TN	KNOXVILLE	19.0	90	3584	1282	3643	1392	58.4
UCA	NY	UTICA	-6.0	85	7580	386	4660	1683	46.6
UIL	WA	QUILLAYUTE	27.0	74	5411	20	5869	44	49.1
UIN	IL	QUINCY	3.0	90	5580	938	5460	849	50.8
VCT	TX	VICTORIA	32.0	95	1270	3217	1123	3608	70.0
VRB	FL	VERO BEACH	43.0	91	544	3582	477	3604	73.2
VTN	NE	VALENTINE	-8.0	94	6861	917	7279	527	47.2
VWS	AK	VALDEZ	7.0	66	8735	6	7074	23	38.3
WMC	NV	WINNEMUCCA	3.0	94	5696	736	6236	611	49.3
WRL	WY	WORLAND	-13.0	93	7336	1010	7757	467	45.4
YAK	AK	YAKUTAT	2.0	63	8591	0	9295	1	39.5
YKM	WA	YAKIMA	5.0	92	5433	734	6204	699	48.9
YNG	OH	YOUNGSTOWN	4.0	86	6566	394	6239	443	48.5

7C.3.1 Developing Monthly Heating and Cooling Degree Day Fractions

Table 7C.3.2 and Table 7C.3.3 show the 10-year average monthly HDD and CDD data based on NOAA data for each weather station.[3] This data was then used to determine the monthly fractions of HDD and CDD as shown in Table 7C.3.4 and Table 7C.3.5. Monthly HDD are used to disaggregate the annual energy use provided by RECS and CBECS by month. The monthly energy use is then combined with monthly energy prices to find the monthly operating cost (see appendix 7B and appendix 8E for more details).

Table 7C.3.2 Weather Station Monthly Heating Degree Day Data (10-Year Average)

Station Location			10-year Average Monthly HDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
ABE	PA	ALLENTOWN	1105	974.2	767.3	409.1	167.9	15	1.4	3.7	73.7	340.9	656.9	956.2
ABI	TX	ABILENE	589	456	242.4	85.5	22.1	0	0	0	2.9	87.9	292.5	581.1
ABQ	NM	ALBUQUERQUE	851	649.4	467.4	228.7	67.4	0.5	0	0	14.8	201.1	534.8	855.4
ABR	SD	ABERDEEN	1631	1421.1	1083.2	619.2	282.6	55.2	10.4	20.5	182.8	588	1025.7	1524
ABY	GA	ALBANY	449	358.2	210.5	54.6	4.8	0	0	0	0	56.6	244.9	379.7
ACT	TX	WACO	527	386	211.6	67	10.3	0	0	0	0.2	57.5	244	503
ACY	NJ	ATLANTIC CITY	950	836.2	693.7	367.5	149.4	13.2	0.1	0.1	39.5	247.7	539.9	800.5
ADQ	AK	KODIAK	1069	951.5	1052.1	822.4	621.8	427.8	305	294.5	440.4	731.6	955.6	1035.4
AGS	GA	AUGUSTA	579	465	303.8	103.5	14.3	0	0	0	1	105.5	346.8	495.8
AHN	GA	ATHENS	652	512	340.2	127.1	28.5	0.4	0	0.3	3	133.9	390.7	570.1
AKN	AK	KING SALMON	1565	1243.8	1409.8	956.3	622.6	409.6	302.2	314	486.6	892.7	1327.3	1418.4
ALB	NY	ALBANY	1256	1093.9	917.5	488.9	212.5	34.3	2.3	9	111.5	413.3	731.9	1081.6
ALI	TX	ALICE	237	163.1	69.5	8.7	0.2	0	0	0	0.1	8	82.6	222.6
ALO	IA	WATERLOO	1467	1248	902.7	492.6	198	16.3	4.8	7.2	129.7	470.1	849.3	1335.7
ALS	CO	ALAMOSA	1526	1171.4	922.6	657.7	406	125	19.9	60.6	260.1	645.1	1016.7	1467.2
ALW	WA	WALLA WALLA	877	711.8	552.4	387.4	178.1	48.1	1.2	2.7	48	337.9	664.8	939.8
AMA	TX	AMARILLO	829	707.6	465.2	248.7	86.2	0.9	0	0.2	22.9	221.3	505.5	837.7
ANC	AK	ANCHORAGE	1490	1234.2	1235.3	847.4	510.3	289.2	186.8	239.9	447.2	855.5	1304.2	1403.9
ANJ	MI	SAULT ST MARIE	1500	1336	1177.2	730.3	396.3	133.2	52.5	53	231.8	565.9	902.3	1320.1
AOO	PA	ALTOONA	1143	1026.9	815.4	433.7	201.1	29.4	6.6	11.3	114.4	387.8	698	1007.7
APN	MI	ALPENA	1399	1269.3	1111	691.5	369	107	34.5	48	223.4	546.2	857.6	1232.5
ART	NY	WATERTOWN	1358	1251.3	1036.8	588.8	294.8	78.1	14.7	29.9	171.7	458.5	768.8	1147.5
AST	OR	ASTORIA	665	590.3	581.6	494	356.3	223.1	134.3	113.1	172.5	362	539.4	695.6
ATL	GA	ATLANTA	637	506.6	328.7	115.9	26.2	0.3	0	0.1	1.7	115.6	362.6	549.6
AUG	ME	AUGUSTA	1360	1166.1	1007.6	586.5	309.1	91.3	9.9	19.9	160.4	465.8	786.4	1176.4
AUS	TX	AUSTIN	477	331.9	181.7	53.2	6.6	0	0	0	0.4	45.6	218.3	438.1
AUW	WI	WAUSAU	1548	1336.9	1065	613.6	281.3	57.2	14.7	21.3	199.6	554	934	1403.2
AVL	NC	ASHEVILLE	844	701.9	540.4	261.8	98.3	4.4	0.3	0.5	29.5	272.9	568.3	750.2
AXN	MN	ALEXANDRIA	1677	1469	1141	637.7	293.4	54.8	9.2	16.9	177.9	572.1	1000.4	1536.8
AYS	GA	WAYCROSS	390	291.3	159	40.4	2.5	11.9	0	0	0	42.6	193.2	317.3
BDL	CT	HARTFORD	1163	1008.9	834.6	435.6	190.8	26.2	1.4	4.2	83	353.8	666.6	998.1
BDR	CT	BRIDGEPORT	1041	914.7	771.5	427.2	181.5	19.9	0.3	1	42.8	269.5	568	876.8
BET	AK	BETHEL	1830	1490.8	1692.2	1201.1	692.7	368.4	289.2	327.3	532.4	######	1478.3	1651.1
BFD	PA	BRADFORD	1320	1212.3	1025.8	614.8	341.5	118.9	59	75.5	233.5	546.1	837.6	1162.7
BFF	NE	SCOTTSBLUFF	1144	1015.2	758.8	531.5	263.7	42.6	4.1	6.7	119.2	490.8	807.7	1217.7
BFL	CA	BAKERSFIELD	480	317.4	210.8	123.4	17.9	1.5	0	0	0.8	43.8	242.2	481.8
BGM	NY	BINGHAMTON	1284	1139.3	976.7	555.9	267.3	67.1	13.4	27.6	162.2	460.9	770.9	1124
BGR	ME	BANGOR	1422	1225.9	1054.5	631	329.5	96.6	11.6	28	187.4	492.4	826.3	1222.8
BHM	AL	BIRMINGHAM	626	499	296.9	103.6	27.3	0	0	0	2.3	120.2	355.5	541.4

Station Location			10-year Average Monthly HDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
BIL	MT	BILLINGS	1135	1016.1	798.1	566.8	318.1	85.4	2.3	15.3	140.9	507.3	836.3	1207.3
BIS	ND	BISMARCK	1577	1383.2	1076.2	640.1	324.4	75.5	9.7	21.9	188.8	611.2	1039.5	1531.1
BKE	OR	BAKER	1216	951.5	833.7	657.8	414.5	223	35.3	61.7	245.4	625.5	926.2	1222.7
BKW	WV	BECKLEY	1019	897.1	696.6	348.1	174.7	25.5	10.7	5.9	83.4	368.1	655.5	914.6
BLH	CA	BLYTHE	288	179.4	67.6	10.1	0	0	0	0	0	2.7	87.8	333.8
BLI	WA	BELLINGHAM	779	670.1	629.7	494.3	324.2	183.5	75.2	71	188.8	433.6	633.6	800.9
BNA	TN	NASHVILLE	803	653.9	432.3	175.1	50.7	0.7	0	0	9.3	186.5	471.2	706.1
BOI	ID	BOISE	1037	774.2	621.8	438.3	204.5	53.8	0.4	5.3	60	361.6	723.3	1027.9
BOS	MA	BOSTON	1066	941.2	809.3	457.2	221.6	48.9	2.6	3.6	63	297.3	588.6	902.6
BQK	GA	BRUNSWICK	383	306.6	174.9	52.5	2.5	0	0	0	0	40.2	179.5	295.4
BRL	IA	BURLINGTON	1226	1061.9	715.7	347.4	126.3	3.6	2	2	68.9	345	667.1	1098.5
BRO	TX	BROWNSVILLE	151	101.1	36.4	7.4	0.1	0	0	0	0	0.5	44.6	144.3
BTM	MT	BUTTE	1351	1206.2	1019.1	796	552.8	299.3	57.6	113.3	350.4	732.9	1085.4	1444.3
BTR	LA	BATON ROUGE	399	297.4	156.2	38.2	5.8	0	0	0	0	48.1	213.8	359.3
BTV	VT	BURLINGTON	1365	1195.4	1032.5	567.4	247.2	50.7	5	18.3	145.2	464.7	776.7	1173.7
BUF	NY	BUFFALO	1201	1119.2	944.3	540.5	236.3	40.4	4.8	8.5	105	403.6	703.8	1046.4
BWG	KY	BOWLING GREEN	867	723.7	482.6	210.9	64.2	0.8	0	0	18.1	224.4	518.4	765.3
BWI	MD	BALTIMORE	942	826.5	633.2	305.9	106.6	3.6	0	0	31.3	251.1	547.7	818.8
BYI	ID	BURLEY	1151	914.4	758.3	565.4	327.7	124.8	4.1	20.7	156.3	509.5	801.5	1126.6
CAE	SC	COLUMBIA	586	464.4	305.9	94.2	14	0	0	0	2	102.6	350.9	504
CAK	OH	AKRON CANTON	1174	1065.5	836.4	432.1	186.1	28.8	3.8	5.1	91.1	391.2	702.1	1019.9
CAO	NM	CLAYTON	874	776.5	576.6	351.7	133.9	7.2	0.3	2.4	44.2	282.9	555.4	905.2
CAR	ME	CARIBOU	1632	1393.7	1235.9	753.2	406.4	137	33.2	72.8	272.7	612.3	949.6	1404.5
CDB	AK	COLD BAY	1131	999.2	1156.1	935.9	760.1	553.4	422.3	380.2	499.7	738.6	931.8	1034.5
CDC	UT	CEDAR CITY	1134	885.5	739.9	534.7	278.1	56.1	0	2.9	100.6	452.8	751.8	1134.5
CDV	AK	CORDOVA	1182	1037.5	1086.6	831.8	603.1	419.8	335.8	344.1	476.6	769.5	1059.6	1137.7
CHA	TN	CHATTANOOGA	728	578.1	374.6	139.4	35.7	0	0	0	3.2	150.5	435.4	641.9
CHS	SC	CHARLESTON	476	374	241.7	66.8	7.3	0	0	0	0.2	63.4	249.4	373.5
CID	IA	CEDAR RAPIDS	1410	1217	857.3	461.4	186.2	15.5	6.6	6.7	126.9	454.4	803.2	1285.3
CLE	OH	CLEVELAND	1137	1036.4	835.2	443.1	192.5	27.7	3.7	4	77.7	355.6	664.3	985
CLL	TX	COLLEGE STATIO	420	294.3	150.2	39.9	4.5	0	0	0	0	32.3	172	381.4
CLT	NC	CHARLOTTE	723	580.5	415.7	161.5	45.1	0.3	0	0.1	7.7	170	450.5	628
CMH	OH	COLUMBUS	1085	965.4	699.8	322.4	122.8	5.5	0	1.5	46.6	323.5	630	936.7
CNK	KS	CONCORDIA	1117	932.3	637.4	351.4	122.8	5.1	1	1.1	56.5	315.2	664	1087.3
CNM	NM	CARLSBAD	635	456.2	261.2	89	25.5	0	0	0	4.4	98.1	354.7	636.5
COD	WY	CODY	1179	1063.6	810.2	633.8	374.1	137	12.5	33.4	186.7	563	878.5	1239.5
CON	NH	CONCORD	1331	1152.4	990.9	565.7	279.8	72.9	8.2	26.1	165.3	475.2	795.3	1152.5
COS	CO	COLORADO SPRIN	1043	929.7	732.7	520.8	267.8	41	5.9	12.3	114.3	453	730.2	1090.3
COU	MO	COLUMBIA	1061	900.6	583.7	284.8	102	2	0	1.1	44.2	294.6	593.2	969.7
CPR	WY	CASPER	1222	1097.3	876.2	675.7	405.5	117.8	10.5	20.7	193.2	587.6	885.8	1274.8
CRP	TX	CORPUS CHRISTI	248	162.2	67.8	9.9	0.2	0	0	0	0	7.7	85.3	224.4
CRW	WV	CHARLESTON	924	809.8	583.9	248.5	103.4	3.1	0	0.5	36.3	278.7	565.7	821.4
CSG	GA	COLUMBUS	527	411.5	240.9	66.2	8.4	0	0	0	0.4	72.9	274.5	445.3
CSV	TN	CROSSVILLE	887	740.4	534.4	251.2	98.9	3.1	0.8	0	31.7	264.4	540.5	768.1
CTB	MT	CUT BANK	1260	1172.7	1008.2	728	460.7	236.2	45.6	84.9	283.6	663.7	991.3	1353.7
CVG	OH	CINCINNATI	1044	907.2	644.3	298.3	111.3	4.3	1.2	1	42.1	310	623.1	916.3
CXY	PA	HARRISBURG	1030	909.1	697.3	353.3	136	7.6	0.3	1.9	51.9	295.3	612.9	904.4
CYS	WY	CHEYENNE	1113	1047.4	852.2	662.1	402.1	103.2	13	24.4	187.1	573.9	833.3	1183
DAB	FL	DAYTONA BEACH	216	166.5	98.6	14.7	0.4	0	0	0	0	11.4	70.9	146.8
DAY	OH	DAYTON	1146	1007.8	738.1	365.7	148.2	9.2	1.6	3.1	65.8	348.5	668.9	999.6

Station Location			10-year Average Monthly HDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
DBQ	IA	DUBUQUE	1434	1243.2	904.2	493.4	214.5	22.1	9.7	9.4	142.3	463.8	821.8	1306.7
DCA	DC	WASHINGTON	851	738.4	547.8	233.6	62.8	0.9	0	0	7.7	173.3	464.9	733.7
DDC	KS	DODGE CITY	984	848.8	588.6	334.3	116.5	3.7	1.3	0.1	40.1	278.4	616	1001.9
DEN	CO	DENVER	1039	943.7	712	508.4	256.1	39.7	3	6.2	91.5	430.1	714.3	1098.5
DFW	TX	DALLAS FT WORT	543	414.9	213.4	65.8	11.8	0	0	0	0.2	54.8	243.8	523.1
DLH	MN	DULUTH	1675	1437.3	1173.5	736	418.8	146.6	40	52.4	248.3	628.6	1035.3	1532
DRT	TX	DEL RIO	388	235.9	92.5	15.7	1.1	0	0	0	0.1	16.5	149.6	377.8
DSM	IA	DES MOINES	1300	1105.1	753	376.3	132.9	4.5	0.4	1.5	66	358.9	723.5	1181
DTW	MI	DETROIT	1212	1086.4	850.3	452.7	179.7	17.3	2.3	4.5	83.6	375.5	707.6	1056.9
DUG	AZ	DOUGLAS	580	422.7	294.4	111.2	15.3	0	0	0	0	74.2	298.8	573.4
DUJ	PA	DU BOIS	1238	1125.5	905.9	502.3	247.1	60	17	25	148.9	448.3	751.6	1089.5
EAU	WI	EAU CLAIRE	1553	1336.3	1028.8	569	255.1	42.6	9.4	15.7	170.1	535.9	919.5	1420
EGE	CO	EAGLE	1364	1080.6	874	638.7	380.1	102.5	5.1	25.4	204.5	585.4	915.2	1307.1
EKA	CA	EUREKA	589	515.2	535.9	494.4	409.1	315.2	278.8	265.5	297.2	365.5	450	582.5
EKN	WV	ELKINS	1107	999.5	797.4	451.4	235.6	48.9	20.7	10.4	127.8	431.4	742.2	984.5
EKO	NV	ELKO	1248	959.4	799.4	592.7	338.4	109	1.8	14.2	142.2	522.6	836.4	1198.6
ELP	TX	EL PASO	576	391.3	203.4	56.4	10	0	0	0	0.6	49.7	298.4	567.2
ELY	NV	ELY	1241	1008.9	866.1	658.6	431	152.2	5.3	31.4	204.2	572.3	854.3	1226.3
ENA	AK	KENAI	1535	1261	1290.7	876.8	570.6	370.1	265.2	300.1	461.6	839.5	1291.1	1429
ERI	PA	ERIE	1133	1066.5	911.2	521.6	245	42.4	4.8	6.3	84.4	356.9	653.7	973.9
EUG	OR	EUGENE	753	630.2	562.7	446.9	293.1	144.4	20.4	22.8	92.2	357.8	587.8	784.1
EVV	IN	EVANSVILLE	965	829.3	549.6	244	78.8	1.4	0	0	25.1	253	568.8	856.1
EWN	NC	NEW BERN	626	533.4	383.7	141.9	27.6	0	0	0	1.6	108.3	335	517.3
EWR	NJ	NEWARK	983	854.6	677.4	332.9	109.2	7.5	0	0.8	24.3	233.4	535.1	831.4
EYW	FL	KEY WEST	33	17.5	6.1	0.2	0	0	3.4	0	0	0	0.9	12.2
FAR	ND	FARGO	1709	1508.7	1167.3	619.6	277.3	48.2	9.5	21.5	170.9	562.6	1016	1562.3
FAT	CA	FRESNO	518	349.4	235.6	130.2	20.9	1.1	0	0	0.9	40.8	252.7	507
FCA	MT	KALISPELL	1129	938.5	746.4	497.2	240	120.2	13.2	43.9	205.1	520.5	882.2	1171.3
FDY	OH	FINDLAY	1195	1071.5	801.6	415.8	162.4	13.6	2.7	4.1	80.2	365.4	683.6	1034
FLG	AZ	FLAGSTAFF	1086	928.5	826.2	625	400.8	123.7	9.8	38.3	198.7	535.6	775.8	1087.7
FLL	FL	FT LAUDERDALE	52	33.8	14.8	0.5	0	0	0	0	0	0.3	5	27.9
FLO	SC	FLORENCE	600	486.3	327	105.5	19	0	0	0	2.2	105.9	333	488.4
FMY	FL	FORT MYERS	101	63	31.7	1.7	0	0	0	0	0	2.7	18.9	60.1
FNT	MI	FLINT	1288	1157.2	929.6	520.1	239	39.1	11.5	14.1	137.1	444.4	762.6	1118
FSD	SD	SIOUX FALLS	1485	1277.3	946.1	535.6	238.9	32.1	5.5	9.2	132.1	495.5	905.1	1403.6
FSM	AR	FORT SMITH	738	589.4	341.2	129.6	34.9	0	0	0	3.6	129.8	375.4	695.2
FWA	IN	FORT WAYNE	1229	1093.5	797.3	422.8	167.3	12.9	3.1	4.9	88.3	385.8	714.2	1072.9
FYV	AR	FAYETTEVILLE	862	727.5	482.2	243.1	88.8	1.7	0.4	0.2	30.4	247.7	503.3	814.7
GCK	KS	GARDEN CITY	1020	868.8	600.5	351.8	117.3	4.7	1	0.3	39.3	301	627	1032.3
GEG	WA	SPOKANE	1111	915.6	779.2	560.6	302	143.1	15	21.3	137	516.7	868.6	1154
GFK	ND	GRAND FORKS	1786	1603	1270.7	680.9	343.5	70.2	18	35	208.7	624.8	1098.5	1656.5
GFL	NY	GLENS FALLS	1382	1209.8	1030.4	568.8	271.5	65.6	10.5	29	187.9	497.4	806.1	1171
GLD	KS	GOODLAND	1068	953.1	700.5	457.2	202.8	21.1	2.1	2.6	86.2	407.5	718.8	1099.9
GLS	TX	GALVESTON	291	208.7	87.8	14.1	0.6	0	1.6	0.2	0	6.4	83.9	239.7
GNV	FL	GAINESVILLE	319	239.1	145.7	30.8	2.2	0	0	0	0	30	137.4	244.3
GRB	WI	GREEN BAY	1454	1272.6	1027.7	587.9	273.3	51.1	10.9	17.6	175.9	496.5	850.5	1306.5
GRI	NE	GRAND ISLAND	1221	1025	735.7	416.3	162	11.9	1.1	2.2	81	394.3	755.3	1198.6
GRR	MI	GRAND RAPIDS	1241	1122.3	897.6	494.9	214.6	27	5.6	8.2	110.8	420.5	741.5	1080.3
GSO	NC	GREENSBORO	771	636.1	461.1	185.4	56.1	1.6	0	0.2	14.2	184.2	472.5	677.2
GSP	SC	GREENVILLE	682	550.7	385	138.1	37.8	1.1	0	0	5	149.4	411	599.3

Station Location			10-year Average Monthly HDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
GTF	MT	GREAT FALLS	1161	1088.6	905.5	663.8	414.7	184.8	19.4	46.2	213.1	572.2	913.2	1251.3
GUP	NM	GALLUP	1104	876.6	753.5	530.5	285.4	46.6	0.2	2.7	110.1	472.2	789.7	1086.5
GWO	MS	GREENWOOD	623	502.8	297.1	105.7	25.1	0	0	0	3.3	132.2	328.9	557.4
HAT	NC	CAPE HATTERAS	373	329.4	233.5	61.9	16.2	0	0	0	0.5	16.4	91.3	237.1
HBR	OK	HOBART	783	648.6	392.6	190.4	48	0	0.1	0	6.4	151.9	422.4	781.8
HIB	MN	HIBBING	1778	1526.9	1214	758.6	433.5	165.2	69.5	110.6	333.7	698.1	1101	1625.7
HKY	NC	HICKORY	772	630.9	452.5	183.1	57.4	1.6	0	0.2	14	189.6	470	679.4
HLN	MT	HELENA	1226	1046.2	854.1	613.5	356	141	5.8	28.5	177.3	569.8	941.1	1310
HNL	HI	HONOLULU-OAHU	0	0	0	0	0	0	0	0	0	0	0	0
HOM	AK	HOMER	1255	1082.8	1145.7	846.7	620.8	431.4	320.5	330.6	455.6	782.2	1105.9	1181.3
HON	SD	HURON	1498	1297.7	970.1	554.8	244	38.9	7.7	8.9	135.5	519.2	939.3	1436
HSV	AL	HUNTSVILLE	711	571.7	361.3	133.3	32.6	0	0	0	6.1	151.1	416.2	614.9
HTL	MI	HOUGHTON LAKE	1411	1282.7	1087.2	639.7	317.2	93.7	42.8	60.3	235.2	557.4	865.7	1240.9
HTS	WV	HUNTINGTON	943	806.7	583.7	249	103	2.3	0.6	0.5	38.9	288.8	578.9	835.4
HUL	ME	HOULTON	1577	1372.8	1198.1	745.3	425.8	160.1	45.6	81.6	277.2	605.6	919.2	1360.8
HVR	MT	HAVRE	1395	1262	1013.9	635.3	361.5	138.9	11.4	39	214.6	606.2	1011.9	1459.1
IAH	TX	HOUSTON	363	256.5	128.3	27.9	2.4	0	0	0	0	22.7	155.4	332.8
ICT	KS	WICHITA	974	807.2	516	259.4	73.5	1.3	0.2	0.1	19.6	228.8	553.3	944.2
IDA	ID	IDAHO FALLS	1409	1167.1	897.1	613.5	366.4	150.5	8.5	31.3	195.7	591.5	917.8	1307.8
ILG	DE	WILMINGTON	972	857.8	666.1	335.7	116.5	6.6	0	0.5	33.6	253	555.4	833
ILM	NC	WILMINGTON	587	498.8	359.1	124	25.2	0	0	0	0.9	99.5	324.4	487.2
IND	IN	INDIANAPOLIS	1120	975.8	673.3	324.7	123.4	5.4	1	1.4	44.7	320.2	648.3	996.2
INL	MN	INT'L FALLS	1850	1609.9	1279.7	765.3	437.1	155.3	70.8	117.4	327.1	703.2	1127.1	1698
INW	AZ	WINSLOW	937	697.8	526	293.2	100.5	3	0	0	17.2	264.9	574.5	907.2
IPT	PA	WILLIAMSPORT	1145	1009	790.6	415.9	175.9	16.3	1	4.4	80.8	358	684.8	993.7
ISN	ND	WILLISTON	1592	1416.8	1119.8	662.4	364	103.4	11.7	32	213.2	661.3	1093	1587.8
ITO	HI	HILO-HAWAII	0	0	0	0	0	0	0	0	0	0	0	0
JAX	FL	JACKSONVILLE	358	273.4	170.7	44.4	3.3	0	0	0	0	35.1	169	275
JKL	KY	JACKSON	911	772.1	534.5	224.3	91.7	2.3	1.2	0.4	35.6	256.7	516.9	789.8
JLN	MO	JOPLIN	913	762.9	481.2	235.5	82.7	2.7	0.1	0.5	26.2	232	487.2	844.5
JNU	AK	JUNEAU	1105	991.1	1017.1	734.8	487.3	310.9	255.4	278.1	426.8	693.1	984.7	1118
JXN	MI	JACKSON	1268	1138.9	893.6	493.2	226.1	36	12	13.4	136.4	444.7	748	1104
KTN	AK	KETCHIKAN	905	831.8	861.5	670.2	463.7	296.2	206.3	194.5	327.2	581.6	792.8	913.2
LAF	IN	WEST LAFAYETTE	1176	1030.8	719.1	368.2	150.6	9.7	2.7	3.8	68.6	351.8	670.7	1040.2
LAN	MI	LANSING	1280	1148.4	919.2	513.5	232.2	35.6	12.1	13.6	136.7	449.7	762.1	1118.8
LAS	NV	LAS VEGAS	479	325.8	155.7	50.7	5.1	0	0	0	0	23.5	197.7	517.3
LAX	CA	LOS ANGELES	217	212.7	193.2	137.8	59	12.2	2.3	2	3.8	30.5	100.4	242.1
LBB	TX	LUBBOCK	724	578.8	352.1	158.3	53.2	0.1	0	0	11.2	151.4	414.9	728.8
LBF	NE	NORTH PLATTE	1213	1052.7	781.5	509.3	244.6	29.5	4.4	4.9	128.4	493.6	836.3	1248.5
LCH	LA	LAKE CHARLES	384	284.4	147.4	34.7	4.5	0	0	0	0	32.4	183.9	346
LEB	NH	LEBANON	1374	1193	1023.9	581.3	270.8	66.7	7.5	24.3	160.5	485.8	808.2	1177.7
LEX	KY	LEXINGTON	974	841.2	593.9	271.4	101.8	2.8	0.5	0.4	36.6	280.5	586.5	859.2
LFK	TX	LUFKIN	464	342.2	181.3	53.2	7.2	0	0	0	0	52.3	232.9	430.4
LFT	LA	LAFAYETTE	378	276.5	143.6	31.3	4.1	0	0	0	0	38.4	181.6	341.1
LGA	NY	NEW YORK	942	830.6	682.2	333.2	111.4	7	0.1	0.6	13.3	190.3	481.8	780
LIH	HI	LIHUE-KAUAI	0	0	0.2	0	0	0	0	0	0	0	0	0
LIT	AR	LITTLE ROCK	701	565.9	341.2	120	30.1	0	0	0	2.6	125.3	375.7	644.4
LND	WY	LANDER	1315	1113.1	850	634	373.7	110.4	5.2	17.9	159.4	580	900.9	1354.5
LNK	NE	LINCOLN	1256	1046.4	723.4	396.1	136.8	6.1	0.8	2.4	78.5	382.6	743.3	1192.7
LOL	NV	LOVELOCK	1042	761.7	632.6	427.2	183.2	36.3	0	3.8	70.6	390.6	722.3	1063.4

Station Location			10-year Average Monthly HDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
LRD	TX	LAREDO	218	134.3	38.9	4.7	0.2	0	0	0	0	4.4	66.4	209.3
LSE	WI	LACROSSE	1460	1259.4	931.5	485.4	196.6	21.5	2.6	5.6	113.9	442.2	820	1325.9
LWS	ID	LEWISTON	881	722.1	600.4	421.6	196.1	57.2	1.1	4.1	55.1	380.7	704.4	955
LWT	MT	LEWISTOWN	1244	1160.3	964.5	736.5	484.7	235.3	35.4	67.4	256.4	632.9	964.5	1302.2
LYH	VA	LYNCHBURG	890	761.5	560.7	258	105.6	4.5	0	1.2	34.9	265.2	568.3	799.9
MAF	TX	MIDLAND ODESSA	627	464.2	258.4	86.7	22.7	0	0	0	5	88.6	337.5	610.1
MBS	MI	SAGINAW	1293	1173.2	953.4	537.7	237.5	38.8	9.7	15.2	132.8	440.7	764.4	1131.6
MCB	MS	MCCOMB	493	380.8	213.8	67.3	12.9	0	0	0	0.3	74.5	264.3	427
MCI	MO	KANSAS CITY	1095	928.4	604.9	306.1	101.1	3.1	0.2	0.5	44.2	290.2	608.1	1015.6
MCN	GA	MACON	556	441.2	284.7	96.7	15.2	0	0	0	1.1	100	338.6	484
MCO	FL	ORLANDO	172	120.6	63	7.3	0	0	0	0	0	8.9	48	113.4
MCW	IA	MASON CITY	1525	1303.7	981.3	538.6	231.7	27.2	7	14.3	149.8	509.6	900.6	1397.3
MEM	TN	MEMPHIS	696	561	335.1	117.5	26.6	0	0	0	1.3	121	374.3	620.7
MFD	OH	MANSFIELD	1202	1079.9	842.6	444.3	197.1	32.3	7.4	8	101.1	403	707.3	1039.3
MFE	TX	MCALLEN	157	106.6	28.2	10.1	0	0	0	0	0	1.7	49.1	147.4
MFR	OR	MEDFORD	786	593.3	527.3	372.5	172.9	51.2	0.5	2.4	38.7	276.2	585.8	811.7
MGM	AL	MONTGOMERY	529	403.3	230.4	65.9	12.1	0	0	0	0.9	85	303.8	451.8
MGW	WV	MORGANTOWN	1003	908.1	673.3	325.9	141.5	13.1	3.8	1.6	56.2	321.1	597.6	873.6
MHS	CA	MT SHASTA	883	739.8	714.1	535.9	303.7	125.7	9.4	16.2	113	415.2	669.8	901.9
MIA	FL	MIAMI	46	28.5	11.5	0.3	0	0	0	0	0	0.1	4.7	22.9
MKE	WI	MILWAUKEE	1291	1128.2	900.7	557.2	275.6	57.1	7.7	5.7	105.6	401.4	751.9	1152.9
MKG	MI	MUSKEGON	1198	1109.3	919.7	536.9	255.3	42.3	11.9	12.9	121.6	421.2	723.7	1052.4
MKL	TN	JACKSON	788	652.7	417.1	179.5	50.2	0.3	0	0	13.2	197.9	470.9	700.8
MLB	FL	MELBOURNE	156	113.1	67.9	10	0	0	0	0	0	8.7	40.1	96.2
MLC	OK	MCALESTER	729	582.9	336.9	151.3	41.6	0.2	0	0	7.9	147.7	369.4	694.2
MLI	IL	MOLINE	1288	1115.8	770.1	392	147.3	9.9	2	2.8	84.5	382.4	723.3	1175.7
MLS	MT	MILES CITY	1347	1178.4	883.9	557.6	297.1	73.5	1	12.5	144.3	541.8	940.8	1387.5
MLU	LA	MONROE	543	425.6	238.2	71.7	11.4	0	0	0	0.3	84.1	298.9	493.9
MOB	AL	MOBILE	425	320.1	181.7	46.5	6.4	0	0	0	0	59.1	234.9	365.7
MOT	ND	MINOT	1583	1438	1168.4	669.3	352.2	89.1	16.8	29.9	190.5	635.5	1073.9	1572.5
MPV	VT	MONTPELIER	1446	1267.9	1105.2	651.4	328	106.1	23.4	54.6	217.5	548.1	864	1254.3
MRB	WV	MARTINSBURG	995	869.9	672.2	337.3	140	8.9	0.4	1.2	55.7	304.4	605.2	884.8
MSL	AL	MUSCLE SHOALS	701	565.3	350.8	134.5	31.7	0.1	0	0	4.3	154.4	411.1	619.8
MSN	WI	MADISON	1404	1221.2	937.6	517	226.3	28.4	7.9	10.6	144	464.5	822.7	1272.3
MSO	MT	MISSOULA	1196	990.7	822.9	613.9	362.7	168.1	14	31.2	192.6	603.8	951.2	1267.1
MSP	MN	MINNEAPOLIS	1517	1290.2	967	506.6	204	22.3	2.3	3.4	111.4	467.1	875	1385.9
MSS	NY	MASSENA	1470	1288.3	1105.5	613.3	289.5	72.7	12.3	32.2	183.6	509.3	851.1	1276.1
MSY	LA	NEW ORLEANS	344	249.4	123	22.4	1.6	0	0	0	0	24.2	150.4	290.1
NYL	AZ	YUMA	158	119.5	40.3	9.5	0	0	0	0	0	1.4	40.9	218.6
OFK	NE	NORFOLK	1307	1108.7	798.8	451.7	179.5	19.4	3.5	4.2	102.9	431.9	797	1267.4
OGG	HI	KAHULUI-MAUI	0	0.1	0.1	0	0	0	0	0	0	0	0	0
OKC	OK	OKLAHOMA CITY	777	628.4	368.7	162.7	41.6	0.5	0	0	7.9	148	406.1	766.1
OLM	WA	OLYMPIA	789	689.6	636.5	508.5	331	183.7	64.9	64.2	168.1	431.1	649.8	823
OMA	NE	OMAHA	1284	1077.8	744.1	384.5	133.7	5.5	1.1	2.4	69	365.7	739.1	1198.2
ORD	IL	CHICAGO	1254	1094.7	815.2	457.4	199.5	23.7	2.4	2.1	80.3	374.9	721.1	1125.1
ORF	VA	NORFOLK	720	627.7	476.7	201.6	55.3	1.5	0	0	2.8	121.5	377.7	594.6
ORH	MA	WORCESTER	1224	1076.3	919.1	509.3	263.2	70.7	7.6	15.3	120.7	419.9	707.1	1058.7
OTM	IA	OTTUMWA	1301	1119.8	771.4	413.8	161.7	11	3.5	3.7	101.1	402.1	735.3	1176.2
P11	ND	DEVIL'S LAKE	1752	1584.9	1278.5	727.8	358	84.2	19.2	35.1	210.4	635.7	1114	1662.8
PAH	KY	PADUCAH	919	780.6	529.9	242.5	78	1.6	0.1	0.2	32.7	260.6	563	835.4

Station Location			10-year Average Monthly HDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
PBI	FL	WEST PALM BEAC	78	53	27.6	2.9	0	0	0	0	0	2.6	12.5	42
PDT	OR	PENDLETON	919	759.6	626.4	459.9	242.6	86.3	4.7	8	88.7	413.1	732.1	998.2
PDX	OR	PORTLAND	730	605.1	529.6	390.3	208.6	88.2	8.3	8	57.7	294.2	550.4	770.6
PHL	PA	PHILADELPHIA	954	839.5	642.9	303.2	89.4	3.4	0	0.6	17.7	219	513.8	805.2
PHX	AZ	PHOENIX	252	157.7	54.3	8.4	0.3	0	0	0	0	2.9	54.8	279.6
PIA	IL	PEORIA	1217	1052.3	712.8	354.9	133.1	5.9	0.9	1.5	60.8	347.2	685	1104
PIH	ID	POCATELLO	1261	1016.7	813.2	593.6	354.5	127	4.7	19.6	166	547.5	869.8	1221.9
PIR	SD	PIERRE	1374	1223.3	931.4	560.1	272.2	49.3	4.7	4.6	118.5	515.1	910.8	1374.2
PIT	PA	PITTSBURGH	1111	1005.1	771.2	386	167.4	20.5	2.8	4.3	80.4	365	671.6	969.2
PKB	WV	PARKERSBURG	1008	886.5	642.3	301.8	120.6	8.5	0.9	0.9	54.8	326.8	611.4	880.6
PNS	FL	PENSACOLA	378	285.7	156.4	33.1	2.2	0	0	0	0	36.7	186.3	314.9
PRB	CA	PASO ROBLES	508	404	337.3	226.3	77.4	18.4	1.5	1.6	14.2	118.3	306.1	525.6
PUB	CO	PUEBLO	1043	892.6	653.7	415.1	163.9	12.7	0.3	1.8	58.6	384.3	700	1083
PVD	RI	PROVIDENCE	1070	942.5	795	444.5	206.5	35.2	1.4	2	66	313.9	603.4	913.9
PWM	ME	PORTLAND	1269	1101.4	964.2	590.6	325.5	91.2	9.3	18.7	150.7	439.7	737.7	1087
RAP	SD	RAPID CITY	1222	1119	869.5	607.3	334.4	81.7	7.1	11.7	149	532.1	877.6	1275.5
RBL	CA	RED BLUFF	519	395	322.4	187.8	44.4	6.5	0	0	4	77.7	315.4	545.6
RDD	CA	REDDING	543	415.6	355.3	216.7	53.4	8.5	0	0	5.9	94.2	355.6	576.4
RDM	OR	REDMOND	968	843.9	774.6	634	404.8	220.6	41.8	58.1	207	546.3	808.6	1052.8
RDU	NC	RALEIGH DURHAM	709	588.6	427.8	162.3	46.6	0.3	0	0	8.5	159.3	425.3	621.3
RFD	IL	ROCKFORD	1334	1164.8	845.8	445.2	187.3	17	4.7	3.8	96.2	405.9	764.4	1213.3
RIC	VA	RICHMOND	796	678.3	496	204.5	58.5	1.1	0	0	9.6	167.7	439.9	685.8
RKS	WY	ROCK SPRINGS	1326	1136.7	940.4	710.5	433.4	144.8	6.9	31.9	209.7	612.2	958.6	1350.6
RNO	NV	RENO	916	705.4	585.3	403.7	180.7	41.6	0	3	51.6	309.3	609.1	923.9
ROA	VA	ROANOKE	833	709.5	519.5	227.4	81.4	2.3	0	0.3	27.6	220.9	523.3	742
ROC	NY	ROCHESTER	1192	1096.2	924.4	526	237.7	43	6.7	12.5	119.4	401.3	712.7	1034.2
ROW	NM	ROSWELL	720	533.5	326.7	127.3	34	0	0	0	6.5	133	430.8	738.3
RSL	KS	RUSSELL	1075	906.8	619.5	345.9	119.5	4.6	0.7	0.6	48.1	303.2	651.3	1067.1
RST	MN	ROCHESTER	1538	1329.5	1001.4	544	236.9	30.2	9.6	15.3	146.4	494.2	888.8	1405.9
SAC	CA	SACRAMENTO	553	389.6	305.5	188.5	48.8	8.2	0	0	4.7	77.2	312.4	539.5
SAN	CA	SAN DIEGO	217	189.5	150.6	101.1	40.9	12	1.5	0.1	0.3	13.9	85.6	226.7
SAT	TX	SAN ANTONIO	373	249.6	118	27.7	3.3	0	0	0	0.7	27	152.7	349.7
SAV	GA	SAVANNAH	450	353.4	221	62.1	6	0	0	0	0.1	52.2	232	354.6
SAW	MI	MARQUETTE	1512	1359.8	1183.3	777.7	436.1	159.1	68.5	80.5	279.5	622.9	982.7	1385.1
SBN	IN	SOUTH BEND	1244	1097.3	837.3	453.5	200.2	24.1	5.1	8.8	98.2	398.2	723.6	1084.7
SBY	MD	SALISBURY	886	781.1	617.5	309.8	128.7	10.5	0.6	0.1	26.8	219.4	490.8	739.6
SCK	CA	STOCKTON	557	386.4	292.2	167.8	37.7	4.9	0	0	2.3	67.2	302.2	537
SDF	KY	LOUISVILLE	918	779.8	518.8	209.2	62.1	1.4	0	0	16.7	219.7	511.9	798.3
SEA	WA	SEATTLE TACOMA	717	609.3	580.4	448.6	268.4	135.6	32	27.2	107.1	361.8	578.4	742.3
SFO	CA	SAN FRANCISCO	439	339.8	310.6	246.2	177.5	97.8	60.9	53.9	50	95.3	243.3	420.5
SGF	MO	SPRINGFIELD	956	801.8	531.9	266.3	99.3	2.8	0	0.7	36.1	272.8	549.1	895.3
SHR	WY	SHERIDAN	1222	1104.9	863.1	649	394.7	135	9.3	26.6	187.2	571.2	913.4	1315.7
SHV	LA	SHREVEPORT	524	403	218	68.8	12.2	0	0	0	0.2	70.2	271.5	488.3
SIT	AK	SITKA	876	811.8	872.4	685.5	507.5	353.6	259.7	233.8	332.9	576.8	782.7	870.9
SJT	TX	SAN ANGELO	552	401	203.9	67.5	13.3	0	0	0	1.2	75.7	271	519.8
SLC	UT	SALT LAKE CITY	1125	827.3	637.4	437.6	207.1	45.2	0	2.1	49.4	353	688.9	1067.4
SLE	OR	SALEM	733	618.2	558.1	435.6	254.2	116.6	13.3	14	76.1	336.4	569.8	763.7
SLN	KS	SALINA	1043	873.1	572.3	303.3	94.1	2.5	0.3	0.5	34.7	270.5	596.1	1023.5
SNP	AK	ST PAUL ISLAND	1282	1170	1334.5	1111.2	929.1	684.9	551	484.7	570.4	805.5	959.2	1103.2
SPI	IL	SPRINGFIELD	1140	987.1	655	311.7	112.9	3.2	0.9	1.7	57.9	327.9	632.4	1025

Station Location			10-year Average Monthly HDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
SPS	TX	WICHITA FALLS	667	531.5	290	109.5	27.3	0	0	0	2.6	99.8	332.6	668.2
STC	MN	SAINT CLOUD	1631	1402.8	1084.7	602.3	276.5	49.1	8.8	17.8	178	559.8	981.7	1499.3
STL	MO	SAINT LOUIS	989	843.8	542.5	235.1	73.3	0.8	0	0.4	24.3	236	539.8	892.6
SUX	IA	SIOUX CITY	1395	1171.6	833.9	450.3	165.6	14.5	2.7	4.4	104.9	441.3	830.6	1315.8
SYR	NY	SYRACUSE	1228	1117.7	945.3	515.7	224	37.7	3.2	9.8	112	390.8	708.4	1064.2
TAD	CO	TRINIDAD	973	848.8	644.5	421.3	192.9	20.4	1.3	4.2	66.3	362.2	662.4	1015.7
TCL	AL	TUSCALOOSA	595	474.9	268.2	95.1	20.6	0	0	0	1.2	114.9	339.8	513.8
TKA	AK	TALKEETNA	1592	1319.2	1303.4	886.9	514.6	252	169.7	260.4	491.8	931.7	1399.8	1523.4
TLH	FL	TALLAHASSEE	393	310.3	178.1	43.9	2.9	0	0	0	0	46.3	207.9	317.7
TOL	OH	TOLEDO	1223	1096.2	844	456.1	184.1	18.2	3.3	4.7	94.5	390.6	724.3	1068.2
TOP	KS	TOPEKA	1062	890.1	576.2	291.5	91.8	1.6	0	0.9	42.5	282.5	599.2	990.2
TPA	FL	TAMPA	163	112.9	61.1	6.6	0	0	0	0	0	5.7	40.4	107.3
TPH	NV	TONOPAH	967	787.5	681	456.4	202.7	40	0	2.8	61.4	355.4	669.6	1003.1
TRI	TN	BRISTOL	889	741.8	542.7	254.1	92.4	1.9	0	0	23.9	271.4	581	790.3
TUL	OK	TULSA	807	660.6	393.7	169	46.7	0.7	0	0.1	8.8	160.1	417.5	775.7
TUP	MS	TUPELO	685	549.8	331.3	125.5	29	0	0	0	3.2	140.1	395	606.3
TUS	AZ	TUCSON	355	263.9	126.4	36.5	2.3	0	0	0	0	12.6	117.1	375
TVC	MI	TRAVERSE CITY	1291	1186.9	1018	628.8	327.7	81.1	22.6	20	160.3	479.2	788.3	1144.2
TXK	AR	TEXARKANA	614	483	278.1	99.7	21.7	0	0	0	1	103.8	314.4	566.3
TYS	TN	KNOXVILLE	799	647.6	441.7	181.8	54.3	0.3	0	0	8.3	196.2	492	712
UCA	NY	UTICA	1083	952.9	752.8	314.2	95.3	10.1	0.4	3.5	37.4	229.5	562.3	927.6
UIL	WA	QUILLAYUTE	713	633.3	645.8	543.7	407.2	278.2	174.8	151.9	215.4	423.7	602.3	738.9
UIN	IL	QUINCY	1168	1012.1	676.8	340	124.1	4.2	0.9	1.7	63.2	338.9	649.8	1058
VCT	TX	VICTORIA	335	228.9	110.3	23.2	1.9	0	0	0	0	21.3	133.9	299.8
VRB	FL	VERO BEACH	142	102.6	62.9	9.5	0	0	0	0	0	6.3	33.6	83.8
VTN	NE	VALENTINE	1253	1116.2	847.6	540.3	262.1	42.6	4.8	6.7	131.8	510.6	860.5	1294.8
VWS	AK	VALDEZ	1110	880.6	900.6	600.8	326.4	155.4	98	111.1	272.2	543.2	930.4	985.2
WMC	NV	WINNEMUCCA	1116	836.1	741.4	565.2	312	100.3	2	14.1	140.4	509.9	797.1	1128.4
WRL	WY	WORLAND	1437	1188	818.1	564.5	312	76.5	4.3	15.3	152.8	562.2	949	1471.9
YAK	AK	YAKUTAT	1107	997.8	1061.8	821	601.4	405.3	301.2	312.5	443	712.5	991.9	1092.7
YKM	WA	YAKIMA	1027	787.7	667.4	466.9	225.3	77.6	6.8	13	117.1	457.2	803.7	1104.6
YNG	OH	YOUNGSTOWN	1183	1074.1	863.2	463.9	215.2	45	9.2	14.5	114.9	410.1	706.6	1026.5

Table 7C.3.3 Weather Station Monthly Cooling Degree Day Data (10-Year Average)

Station Location			10-year Average Monthly CDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
ABE	PA	ALLENTOWN	0	0	0.1	8.7	54.2	187.6	320.8	236.2	91.6	12.7	0	0
ABI	TX	ABILENE	2	8.8	46.4	138	292.2	514.3	587.6	608.2	355.3	136.7	24.7	3.3
ABQ	NM	ALBUQUERQUE	0	0	0.2	9.4	112.1	376.2	455.6	388.4	186.7	14.9	0	0
ABR	SD	ABERDEEN	0	0	0.7	0.6	24.6	108.8	250	160.2	47	5.4	0	0
ABY	GA	ALBANY	9	5.8	38.4	112	316.3	513.2	566.9	564.2	411.9	156	20	11.5
ACT	TX	WACO	6	11.3	51.4	137.8	322	563.2	651.1	691.8	441.2	170.5	44.3	8.7
ACY	NJ	ATLANTIC CITY	0	0	0.4	14.9	64.1	228	392.6	317.2	142.7	27.4	0	0
ADQ	AK	KODIAK	0	0	0	0	0.3	0.6	0.8	0	0	0	0	0
AGS	GA	AUGUSTA	3	1.8	17.3	64.4	213.5	427.5	517.4	514.5	325.5	90.2	3.9	3.5
AHN	GA	ATHENS	0	0.4	15.3	52.6	184.1	407.5	485.8	482.8	282.5	62	2.5	1.3
AKN	AK	KING SALMON	0	0	0	0	0	0	0.5	0.4	0	0	0	0
ALB	NY	ALBANY	0	0	0.1	4.8	38.6	145	267	190.6	64.5	5.3	0	0
ALI	TX	ALICE	46	80.6	174	305.3	478.8	607	662.3	695	531.4	330.4	138.3	74.6
ALO	IA	WATERLOO	0	0	3	4.4	57	176.5	279.7	210.8	68.8	14.5	0.1	0

Station Location			10-year Average Monthly CDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
ALS	CO	ALAMOSA	0	0	0	0	0.2	13.8	63.3	27.3	2.1	0	0	0
ALW	WA	WALLA WALLA	0	0	0	1.4	45.1	102.4	387.8	338.9	117.5	6.5	0.2	0
AMA	TX	AMARILLO	0	0	6	28.8	140	366.1	434.7	420.2	187.1	35.9	0.7	0
ANC	AK	ANCHORAGE	0	0	0	0	0	1.1	3.3	0.2	0	0	0	0
ANJ	MI	SAULT ST MARIE	0	0	0.2	0	10.8	36	100.8	76	16.7	2.5	0	0
AOO	PA	ALTOONA	0	0	0.5	7.5	48.7	138.9	225.8	165.9	57.8	9.9	0	0
APN	MI	ALPENA	0	0	0.6	0	15.5	70	135.6	95.5	23.4	5.8	0	0
ART	NY	WATERTOWN	0	0	0	2.3	26.3	92	173.1	153.3	51.2	6.1	0	0
AST	OR	ASTORIA	0	0	0	0.3	4	1.6	5.6	5.7	8.5	0	0	0
ATL	GA	ATLANTA	1	0.6	19	58.1	203	418.3	474	485.4	301.3	78	3.9	1.4
AUG	ME	AUGUSTA	0	0	0.2	0.3	12.6	65.8	183.9	125.5	35.2	3.1	0	0
AUS	TX	AUSTIN	10	20.2	67.7	160	345.6	549.3	599.1	649.4	441.4	184.3	57.7	12.5
AUW	WI	WAUSAU	0	0	1	0.8	28.7	103.3	201.5	137.5	35	5.6	0	0
AVL	NC	ASHEVILLE	0	0	0.2	7.4	60.6	211.1	283.4	274.9	106.3	10.9	0	0
AXN	MN	ALEXANDRIA	0	0	0.3	1.4	29	95.4	234.9	155.4	42.4	4.3	0	0
AYS	GA	WAYCROSS	10	20.8	63	167	340.3	485.2	566.3	573.9	423.3	184	34.6	22
BDL	CT	HARTFORD	0	0	0.4	7.2	45.2	162.7	322	236.3	91.8	10.3	0	0
BDR	CT	BRIDGEPORT	0	0	0	1.3	30.6	164.8	346	287.7	118.5	14.7	0	0
BET	AK	BETHEL	0	0	0	0	0	1.9	3.3	0.4	0	0	0	0
BFD	PA	BRADFORD	0	0	0	0.9	16.5	48.7	91.9	54.9	20.9	2	0	0
BFF	NE	SCOTTSBLUFF	0	0	0.1	0.9	29.9	158.7	345.2	264.3	73.3	2	0	0
BFL	CA	BAKERSFIELD	1	0.3	11	65.4	219.4	411.4	647.4	582.7	402.9	109.8	6.1	0.1
BGM	NY	BINGHAMTON	0	0	0	4.7	30.4	94.5	181.2	120.5	42.5	4.5	0	0
BGR	ME	BANGOR	0	0	0	0.3	7.3	51.9	167.6	102.8	29.4	0.8	0	0
BHM	AL	BIRMINGHAM	1	3	29.5	79.9	227	443.9	510.1	522.4	324.4	91.9	8.2	3.4
BIL	MT	BILLINGS	0	0	0	2.1	17.3	83.5	320.3	239.2	67.1	3.9	0	0
BIS	ND	BISMARCK	0	0	0	0.2	16.3	81	237.4	162.4	42.9	2.2	0	0
BKE	OR	BAKER	0	0	0	0	5.9	12.1	107.9	70.1	9.8	0.4	0	0
BKW	WV	BECKLEY	0	0	1.7	13.9	45.9	126.5	197.7	186.4	67.8	7.2	0.1	0
BLH	CA	BLYTHE	2	6	83.9	222.4	512	742.4	962.3	919.6	689.3	315.9	65.1	0.8
BLI	WA	BELLINGHAM	0	0	0	0	0.9	4.2	27.5	28	2.5	0	0	0
BNA	TN	NASHVILLE	0	0.6	15.2	56.7	172.9	391.6	472.9	486.8	251.9	55.4	3	1
BOI	ID	BOISE	0	0	0	3.8	42.3	140	456.7	362.9	136.5	8	0	0
BOS	MA	BOSTON	0	0	0.9	4.8	33.6	146.8	314	246.7	98.2	12	0	0
BQK	GA	BRUNSWICK	11	15.3	42.9	131.2	294.7	480.6	559.6	570.7	416.6	193	38.3	29.5
BRL	IA	BURLINGTON	0	0	5.3	20.6	104.8	272.2	359	315.3	129.7	26.9	0.2	0
BRO	TX	BROWNSVILLE	72	113.5	204.4	345.8	493.1	600.4	628.5	669	538.1	387.2	182.1	93.2
BTM	MT	BUTTE	0	0	0	0	0.4	8.8	60.7	26	1.4	0.3	0	0
BTR	LA	BATON ROUGE	18	21.9	70	157.7	336.1	519.7	562.8	579.5	431.9	177.7	38	23.6
BTV	VT	BURLINGTON	0	0	0.5	3.2	27.7	116.5	220.4	162.2	53.1	3.9	0	0
BUF	NY	BUFFALO	0	0	0.8	2.2	40.8	129.8	232.1	185.9	63	8.3	0	0
BWG	KY	BOWLING GREEN	0	0.3	11.6	46.8	151.9	352.1	433.7	444.8	205.3	37.8	2.3	0.7
BWI	MD	BALTIMORE	0	0	1.1	20.4	92.2	284.5	427.3	349.5	155.7	27.5	0	0.2
BYI	ID	BURLEY	0	0	0	0.3	8.4	49.8	224.4	155.3	20.7	2.8	0	0
CAE	SC	COLUMBIA	4	2.4	23.8	89.9	246.5	462	545.8	533.3	345.4	96	6	2.9
CAK	OH	AKRON CANTON	0	0	2.2	6.1	61.3	160.1	257.4	213.3	74.6	12.2	0	0
CAO	NM	CLAYTON	0	0	0.8	10.5	78.2	278.6	379.3	334.5	131.5	17.9	0.6	0
CAR	ME	CARIBOU	0	0	0	0	5	35	100.5	56.7	11.4	0.8	0	0
CDB	AK	COLD BAY	0	0	0	0	0	0	0	0	0	0	0	0
CDC	UT	CEDAR CITY	0	0	0	0.1	8.7	116.6	307	212.1	43	1.8	0	0

Station Location			10-year Average Monthly CDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
CDV	AK	CORDOVA	0	0	0	0	0	0.5	0	0	0	0	0	0
CHA	TN	CHATTANOOGA	0	0.2	15.1	50.6	181.5	410.6	477.4	502.7	277.4	59.4	1.4	0.5
CHS	SC	CHARLESTON	4	4.5	25.9	104.4	262.5	463.1	543.8	540.5	372.9	144.9	18.4	9
CID	IA	CEDAR RAPIDS	0	0	3.7	9.8	61.3	179.2	265.8	212.7	71.5	16.1	0	0
CLE	OH	CLEVELAND	0	0	2.7	10.5	66.4	183.5	280.7	234.3	82.7	15.1	0	0
CLL	TX	COLLEGE STATIO	15	24.3	81.8	181.9	372.4	578.2	634.6	685.9	494.6	220.1	69.9	20.6
CLT	NC	CHARLOTTE	0	0.3	11.1	39.6	153.1	358.5	445.2	432.9	240.4	48.6	1.4	1.3
CMH	OH	COLUMBUS	0	0	3.9	14.6	101.1	247.3	341.8	321.9	131.2	23.8	0	0
CNK	KS	CONCORDIA	0	0	4.4	16.3	104.2	313.7	446.1	376.6	142.7	28.3	0.4	0
CNM	NM	CARLSBAD	0	3.6	21.5	94.3	275.9	537.2	529.2	527.2	284.3	76.5	3.7	0.4
COD	WY	CODY	0	0	0	0.5	10	60.6	243.2	164.4	44.4	7.1	0	0
CON	NH	CONCORD	0	0	0	2.1	19.6	93.5	204.2	137.6	44.9	2.2	0	0
COS	CO	COLORADO SPRIN	0	0	0	0.2	18.5	140.7	246	175	52.1	1.7	0	0
COU	MO	COLUMBIA	0	0	8.5	27.7	116.4	301.9	411.3	392.4	148.5	32.1	1	0
CPR	WY	CASPER	0	0	0	0	5	60.5	239.5	162	31.8	1.2	0	0
CRP	TX	CORPUS CHRISTI	38	70.4	154.4	288.7	443.9	569.5	614.1	667.5	526.9	334.6	127.8	60.2
CRW	WV	CHARLESTON	0	0	7.6	30.4	96.1	248.1	333.7	326.8	141.4	23.7	1	0.2
CSG	GA	COLUMBUS	4	3	27.5	90.1	272.6	484.2	542.6	550.9	379.8	124	12.7	5.7
CSV	TN	CROSSVILLE	0	0	4.4	25.7	91.1	229	312.2	320.2	139.4	18.6	0	0
CTB	MT	CUT BANK	0	0	0	0	3.1	11.5	97.6	67.5	12.9	0	0	0
CVG	OH	CINCINNATI	0	0	6.3	18.6	96.7	253.3	345.1	352.5	148.4	24.8	0.3	0
CXY	PA	HARRISBURG	0	0	0.2	11.2	72.5	232.6	360.5	284.4	121.4	18.2	0	0
CYS	WY	CHEYENNE	0	0	0	0	3.9	64.3	191.5	136.8	28.3	0.5	0	0
DAB	FL	DAYTONA BEACH	36	46	76.8	174.4	334.7	467.5	530.1	555.6	466.9	299.8	101.4	68.6
DAY	OH	DAYTON	0	0	4	12.5	84.7	218.7	304.2	277.5	105.8	19	0	0
DBQ	IA	DUBUQUE	0	0	2.3	4.9	45.7	152.3	240	185.1	61.9	12.2	0	0
DCA	DC	WASHINGTON	0	0	3.4	28.5	127.3	356.9	503.6	450.4	234.7	49.5	0.2	0
DDC	KS	DODGE CITY	0	0	2	20.7	120.3	349.4	485.4	432.7	179.2	36.6	0.3	0
DEN	CO	DENVER	0	0	0	1.2	30.3	168.3	339.4	270.8	86.3	6.6	0	0
DFW	TX	DALLAS FT WORT	5	10.8	51.3	128.1	330.8	581.3	675.2	718	458.3	172.2	40.1	6.6
DLH	MN	DULUTH	0	0	0	0	6.6	34.8	135.1	82.6	20.8	0.9	0	0
DRT	TX	DEL RIO	4	27.9	121.7	268.5	442.8	631.6	670.6	702.2	493.7	256.6	55.7	6.2
DSM	IA	DES MOINES	0	0	4.8	14.9	88.7	262.4	392.8	334.4	123	24.1	0.4	0
DTW	MI	DETROIT	0	0	1.9	3.9	59.7	194.4	299.3	255.6	86.4	13.2	0	0
DUG	AZ	DOUGLAS	0	2.2	5.6	33.5	187.7	459.6	502.1	435.1	299.4	77.9	1.8	0.1
DUJ	PA	DU BOIS	0	0	0	5.2	37.1	90.8	166.3	124.7	40.1	7.6	0	0
EAU	WI	EAU CLAIRE	0	0	1.8	1.6	36	124.6	243.6	170.1	50.2	9.2	0	0
EGE	CO	EAGLE	0	0	0	0	1.6	31.1	133.9	66	7	1	0	0
EKA	CA	EUREKA	0	0	0	0.3	0.6	0	0.2	1.9	1.5	1.2	0.3	0
EKN	WV	ELKINS	0	0	0.1	1.3	22.9	88.2	157.7	149.3	43.2	4.6	0.2	0
EKO	NV	ELKO	0	0	0	0.1	7.2	63.1	289.2	179.9	31.3	1.5	0	0
ELP	TX	EL PASO	0	2	24.6	120.8	329	605.3	591.5	548.6	338	114.9	3.6	0
ELY	NV	ELY	0	0	0	0	1	30.6	161.1	91.6	9.7	0	0	0
ENA	AK	KENAI	0	0	0	0	0	0	0	0	0	0	0	0
ERI	PA	ERIE	0	0	1.1	5.7	45.8	143.3	241.5	203.1	77.2	16.2	0	0
EUG	OR	EUGENE	0	0	0	0.1	5.3	16.2	119.7	118.7	39.6	1.4	0.1	0
EVV	IN	EVANSVILLE	0	0	8.4	31.9	140.6	341.8	415.7	417.6	186.2	39.3	1	0.2
EWN	NC	NEW BERN	1	1.8	12.6	63.6	178.3	385.1	485.8	471	283.5	94.9	9.6	7.4
EWR	NJ	NEWARK	0	0	0.5	16.3	75.9	261.9	441.2	365	165.2	26	0	0
EYW	FL	KEY WEST	186	193.8	257.6	372.2	494.5	556.6	617.1	637	566.5	495.1	309.5	244.6

Station Location			10-year Average Monthly CDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
FAR	ND	FARGO	0	0	0.6	1.2	35	120.3	238.3	158.8	53.4	7.5	0	0
FAT	CA	FRESNO	0	0	6.6	57.7	212	396.7	625	563.5	393.7	109.9	3.7	0
FCA	MT	KALISPELL	0	0	0	7.6	43.1	112.7	316.2	255.5	75.8	11.6	0	0
FDY	OH	FINDLAY	0	0	2.9	8.3	80.9	214.7	292.4	239.4	91.2	17.6	0	0
FLG	AZ	FLAGSTAFF	0	0	0	0	0.1	25.9	93.5	41.7	1.8	0	0	0
FLL	FL	FT LAUDERDALE	170	179.2	238.7	352.6	467.9	542.5	589.8	614.9	546.4	466.9	284	232.8
FLO	SC	FLORENCE	3	2.8	22.1	79.8	219.8	432.4	517.5	503.8	320	95	8.9	6.8
FMY	FL	FORT MYERS	96	115.6	168.2	296.2	453.9	530	574.9	592.4	525.7	400.4	190.8	144.6
FNT	MI	FLINT	0	0	2.2	2	45.6	143.3	227.6	179.3	56.6	10.6	0	0
FSD	SD	SIOUX FALLS	0	0	1.5	6.2	41.3	146.7	302.7	214.7	71.3	10.6	0	0
FSM	AR	FORT SMITH	1	0.1	24.6	69.4	219.4	469	581.2	588	313.3	79.2	7.7	0.7
FWA	IN	FORT WAYNE	0	0	3.1	7.2	73.8	214.7	292.9	223.8	79.9	15	0	0
FYV	AR	FAYETTEVILLE	0	0.1	9.4	35.1	121.6	311.8	418	434.7	167.9	35	2.9	0.8
GCK	KS	GARDEN CITY	0	0	2.8	18.6	112.6	333.2	463.2	410.5	168.8	26.5	0.1	0
GEG	WA	SPOKANE	0	0	0	0.2	16.5	40	242.6	193.8	52.6	1	0	0
GFK	ND	GRAND FORKS	0	0	0	0.5	16.8	77.7	185	125	35.5	3	0	0
GFL	NY	GLENS FALLS	0	0	0	0.9	24.7	90.4	177.9	120.5	34.9	2	0	0
GLD	KS	GOODLAND	0	0	0.8	3.1	53.1	217.8	379.6	309.2	98.8	8.2	0	0
GLS	TX	GALVESTON	12	15.6	88	213.9	404	585	620	668.3	544.2	363.7	135.9	36.1
GNV	FL	GAINESVILLE	20	25.3	54	143.1	313.3	462.4	518.8	536.9	425.9	221.3	51	29.8
GRB	WI	GREEN BAY	0	0	1.3	1.8	27.8	116.1	207.6	142.8	39.4	7.9	0	0
GRI	NE	GRAND ISLAND	0	0	2	9.8	84.5	246.2	386.9	312.5	103.2	17	0	0
GRR	MI	GRAND RAPIDS	0	0	3.1	3.8	51.8	165.4	263.8	212.3	68.6	11.4	0	0
GSO	NC	GREENSBORO	0	0	8.7	37.9	140.5	343.2	435.2	416.3	209.1	41.4	0.9	1
GSP	SC	GREENVILLE	0	0	14	45.4	167.4	386	459.6	449	254.6	53.1	1.6	1.2
GTF	MT	GREAT FALLS	0	0	0.9	0.4	4.3	24.5	188.6	135.2	37.2	0.5	0	0
GUP	NM	GALLUP	0	0	0	0	4.1	82.5	226.1	147.8	28.5	0.3	0	0
GWO	MS	GREENWOOD	6	5.4	36.2	92.6	252.8	451.6	499.8	535	324.1	96.3	21.7	6.5
HAT	NC	CAPE HATTERAS	27	22.3	77.4	190.1	346.8	569.2	661.1	661.8	536.9	338.1	100.2	49.3
HBR	OK	HOBART	0	0.5	19.6	59.1	229.9	500.6	597.9	611	322.2	87.4	6	0.1
HIB	MN	HIBBING	0	0	0	0.1	9.2	24.7	83.9	50.6	7.5	0.3	0	0
HKY	NC	HICKORY	0	0	7.4	33.2	130.5	331.2	400.1	393.8	193.8	34.3	0.7	0.2
HLN	MT	HELENA	0	0	0	0	9.7	44.6	247.4	166.9	34.7	0.5	0	0
HNL	HI	HONOLULU-OAHU	276	258.8	307.2	350.9	416.9	467.3	509.5	524.3	493	470.7	384.3	318.4
HOM	AK	HOMER	0	0	0	0	0	0	0.4	0	0	0	0	0
HON	SD	HURON	0	0	1.5	3.3	36.1	144.2	319.5	229.6	75	6.7	0	0
HSV	AL	HUNTSVILLE	1	1.1	18.9	66	210.3	434	484.9	498.7	285.1	71.4	3.1	1.3
HTL	MI	HOUGHTON LAKE	0	0	1.1	0.2	25.6	78.9	141.3	92.7	22.5	4.8	0	0
HTS	WV	HUNTINGTON	1	0	9.2	29.1	95.8	253.4	337.6	331.5	144.4	24.1	0.9	0.2
HUL	ME	HOULTON	0	0	0	0	5.4	33.6	96.5	60.4	16.9	1.1	0	0
HVR	MT	HAVRE	0	0	0	0	12.8	34.5	220	144.1	27	0.3	0.1	0
IAH	TX	HOUSTON	19	30.7	87.5	186.5	384.3	574.2	608.5	654.6	484	234.8	72	30
ICT	KS	WICHITA	0	0	7.1	33.7	159	399.1	529.2	489.3	226.3	51.2	2.4	0
IDA	ID	IDAHO FALLS	0	0	0	0	4.5	32	164.9	109.5	12.3	1.1	0	0
ILG	DE	WILMINGTON	0	0	0.4	14.1	75	255.8	406.9	333.5	149.3	25.9	0	0
ILM	NC	WILMINGTON	3	2.3	14.4	65.1	184.2	386.8	483.8	453.7	284.5	99.5	9.4	5.2
IND	IN	INDIANAPOLIS	0	0	6.5	15.9	96.6	264	352.7	342.4	144	26.3	0	0
INL	MN	INT'L FALLS	0	0	0.4	0	8.9	29.4	83.4	49.1	11.7	1.1	0	0
INW	AZ	WINSLOW	0	0	1.6	8.2	79.4	288.5	471.8	375	162	12.5	1.1	0
IPT	PA	WILLIAMSPORT	0	0	0	8.1	54.3	178.7	299.9	217.5	78.2	10	0	0

Station Location			10-year Average Monthly CDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
ISN	ND	WILLISTON	0	0	0	0.2	8.5	49	213.7	154.5	34.3	1.8	0	0
ITO	HI	HILO-HAWAII	213	189.3	220.5	231.1	297	310.4	352.6	361.7	351.2	339.9	280.6	243.5
JAX	FL	JACKSONVILLE	15	17.6	42.4	123	283.6	457.2	529.4	544.8	411.1	199.5	36.2	24.2
JKL	KY	JACKSON	0	0	12.5	50.2	112.9	255.9	320	331.4	159	35.6	1.3	0
JLN	MO	JOPLIN	1	0.3	18.9	52.4	153.2	369.5	491.8	491	201.3	52.5	6	0
JNU	AK	JUNEAU	0	0	0	0	0	0.8	0.8	0.2	0	0	0	0
JXN	MI	JACKSON	0	0	1.5	3.3	44.4	138.3	217.9	172.1	57.6	10	0	0
KTN	AK	KETCHIKAN	0	0	0	0	0	2.5	9.2	5.2	0	0	0	0
LAF	IN	WEST LAFAYETTE	0	0	7.6	14.6	86.8	230.9	304.9	277.3	110.4	23.2	0	0
LAN	MI	LANSING	0	0	2.4	2.1	45.1	145.2	238.2	184.7	57.5	9.6	0	0
LAS	NV	LAS VEGAS	0	0.3	36	142.9	417.3	700.1	911.3	823.2	572.2	191.6	19.1	0
LAX	CA	LOS ANGELES	10	4.7	9.5	18.3	37.6	53.4	143.3	153.5	139.3	89.4	37.3	3.4
LBB	TX	LUBBOCK	0	0.1	12.8	66.9	225.2	459.8	484.1	486.2	241	63.6	3.4	0
LBF	NE	NORTH PLATTE	0	0	0.7	2.4	39.6	167.3	344.7	265.1	78.8	7.1	0	0
LCH	LA	LAKE CHARLES	15	18.3	66.7	157.7	350.4	531.7	567.7	597.7	450.3	201.4	51.5	21.7
LEB	NH	LEBANON	0	0	0	1.5	24.2	93.3	195.2	135.6	43.9	3.5	0	0
LEX	KY	LEXINGTON	0	0	6.4	23.2	105.1	272.8	354.3	355.2	161.8	30.6	0.1	0
LFK	TX	LUFKIN	12	18.3	65.6	148.1	333.8	529.8	588.6	635.4	436.1	172.2	46.3	15.8
LFT	LA	LAFAYETTE	19	21.9	79.2	177.6	362.4	540.6	569.7	598.3	448.9	201.7	54.4	26
LGA	NY	NEW YORK	0	0	0	9	72.8	264.1	450	388.6	191.1	35.7	0	0
LIH	HI	LIHUE-KAUAI	245	197.1	238.9	280.9	352.5	398.6	442.2	463.9	444.1	428.8	327	273.5
LIT	AR	LITTLE ROCK	2	1.6	26.2	69.4	233.1	474.9	546.2	566.9	317.5	80.5	9.3	1.3
LND	WY	LANDER	0	0	0	0.2	8.2	80.2	274.4	193.5	35.8	1.2	0	0
LNK	NE	LINCOLN	0	0	3.6	15.8	94.7	271.7	422.4	349.2	114	23.3	0.5	0
LOL	NV	LOVELOCK	0	0	0	2.5	48.2	173.3	444.9	311.9	99.3	5.7	0	0
LRD	TX	LAREDO	51	99	260.1	440	605.8	752.6	751.4	809.1	605.7	410.5	174.9	57.7
LSE	WI	LACROSSE	0	0	3	5.6	54.9	189.6	313.2	236.3	76.5	13.8	0.1	0
LWS	ID	LEWISTON	0	0	0	1.2	36.2	97.4	382	332.9	112.8	4.8	0	0
LWT	MT	LEWISTOWN	0	0	0	0	1.2	16.3	134.1	89.8	20.9	1.1	0	0
LYH	VA	LYNCHBURG	0	0	2.9	22.4	82.5	243.2	356.3	326	129.3	20	0	0
MAF	TX	MIDLAND ODESSA	0	2.4	32	130.1	304	548.6	547.3	552.8	314.7	115.4	7.5	0.5
MBS	MI	SAGINAW	0	0	1.8	1.8	46.7	146.8	224.5	169.2	51.5	11.5	0	0
MCB	MS	MCCOMB	9	10.3	41	104.1	269.3	471.3	502.2	528.9	382.8	133.8	23.3	14.2
MCI	MO	KANSAS CITY	0	0	8.1	26.1	120.4	314.8	434.6	413.4	153.1	33.9	1.7	0
MCN	GA	MACON	3	1.4	17.5	64.7	227.6	446.5	522.6	518.4	330.5	91.8	6.7	2.5
MCO	FL	ORLANDO	49	69.8	115.8	234.7	391.4	500.7	561	580.5	496	332.9	122.1	84.9
MCW	IA	MASON CITY	0	0	1.3	2.2	43.4	147.2	243.7	175.8	50.7	10.8	0	0
MEM	TN	MEMPHIS	2	1.6	32.1	84.8	259.8	497.2	552.5	581.8	350.2	98.3	9.2	0.7
MFD	OH	MANSFIELD	0	0	1.7	7.6	62.2	155.4	234.8	203.1	69.8	13	0	0
MFE	TX	MCALLEN	78	131.6	255	399.5	547.2	663.2	695.4	734.1	582.9	421.7	197.3	92.5
MFR	OR	MEDFORD	0	0	0	3.4	39.7	97.4	356	310.6	147.1	5.3	0	0
MGM	AL	MONTGOMERY	4	5.8	34.6	93.2	258.9	491	543.8	558.9	387.2	123.1	13.4	6.7
MGW	WV	MORGANTOWN	0	0	3.8	20.1	81.2	186.6	287.4	265.3	108.8	21.8	0.6	0
MHS	CA	MT SHASTA	0	0	0	0.3	14.1	42.5	176.1	118.9	36.6	1.7	0	0
MIA	FL	MIAMI	171	183.8	242.7	357.5	479.4	543.3	594.4	613.2	552.1	469.6	284	232.9
MKE	WI	MILWAUKEE	0	0	1.9	3.1	29.9	134	262.9	226.8	78.5	12	0	0
MKG	MI	MUSKEGON	0	0	2.6	1.7	35.5	125.8	219	182.9	59	8.9	0	0
MKL	TN	JACKSON	1	0.8	18.9	63.9	188.5	379.3	442.8	466.6	233.2	53	4.7	1.3
MLB	FL	MELBOURNE	64	77.8	124.4	224.1	380.9	482.4	537.6	564.1	488.1	356.2	157.6	115.2
MLC	OK	MCALESTER	2	3.7	31.8	77.5	199.3	443.5	553.8	571	301.6	87.7	14.1	2.5

Station Location			10-year Average Monthly CDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
MLI	IL	MOLINE	0	0	4.2	10	83.8	234	335.8	283	102.3	21.1	0.1	0
MLS	MT	MILES CITY	0	0	0	1.8	19.4	103.7	356.1	265	75.8	5.9	0	0
MLU	LA	MONROE	6	10.1	45.9	110.8	292.8	508.7	563.3	598.5	395.3	124.3	25.5	7.9
MOB	AL	MOBILE	11	10.9	45.3	115.3	292.3	482.1	526.2	538.8	404.7	157	27.5	16.1
MOT	ND	MINOT	0	0	0	0.6	9.6	62.4	191.3	145.2	37.5	1.1	0	0
MPV	VT	MONTPELIER	0	0	0	0.8	12.1	59.5	124	83.3	24.3	0.7	0	0
MRB	WV	MARTINSBURG	0	0	0.9	13.8	71.1	222.7	344.2	284.4	114.5	17.3	0	0
MSL	AL	MUSCLE SHOALS	1	2	20.6	73.8	214.1	432.2	495.5	509.4	275.2	68.6	5.3	2.5
MSN	WI	MADISON	0	0	3.1	2.4	44.3	153.1	254.8	193.5	61.1	10.1	0	0
MSO	MT	MISSOULA	0	0	0	0.1	4.2	32.8	206.5	137.4	22.9	0.3	0	0
MSP	MN	MINNEAPOLIS	0	0	1.7	2.8	54.3	188.5	349.5	255.8	83	15.4	0	0
MSS	NY	MASSENA	0	0	0	1.4	19.5	91.3	193	128.7	38.1	2	0	0
MSY	LA	NEW ORLEANS	21	25.5	79.5	182.3	375.4	546.6	576.6	599.5	482.2	233.8	53.8	31.2
NYL	AZ	YUMA	21	26.4	126.4	260.2	515.6	756.2	950	924.4	748.5	399.4	117.1	10.3
OFK	NE	NORFOLK	0	0	2.1	12.5	75.1	209.8	354.1	278.9	90	17.3	0	0
OGG	HI	KAHULUI-MAUI	237	204.4	254.9	286	356	399.2	444.1	460.6	430	411.6	326.1	274.9
OKC	OK	OKLAHOMA CITY	0	1.2	21.1	60.8	200.8	447.8	573.3	574.3	292.7	77.6	7.2	0.5
OLM	WA	OLYMPIA	0	0	0	0	2.4	10.2	53.3	48.2	8.1	0	0	0
OMA	NE	OMAHA	0	0	4.7	16.3	96.6	270.6	419.1	347.6	119.9	23.3	0.5	0
ORD	IL	CHICAGO	0	0	4.6	6.2	61.1	200.6	322.5	278	100.2	17.9	0	0
ORF	VA	NORFOLK	1	1	9	48.7	140.4	357.8	485.9	442.8	257.6	75.5	4.5	1.5
ORH	MA	WORCESTER	0	0	0.2	3.4	29.1	101.6	230	164.9	54.5	6.1	0	0
OTM	IA	OTTUMWA	0	0	4.3	13.5	73.2	214	315.4	264.6	88.4	20.6	0.3	0
P11	ND	DEVIL'S LAKE	0	0	0	0	22.7	65.8	179.2	128.2	31.6	5	0	0
PAH	KY	PADUCAH	0	0.1	8.6	33.5	137.3	330	384.6	386.3	175.1	33.2	1.9	0
PBI	FL	WEST PALM BEAC	129	140.9	190.4	308.4	434.2	511.7	577.1	602.3	521.3	432.8	241.2	194.1
PDT	OR	PENDLETON	0	0	0	0.6	24.5	60.5	281.6	230.1	63.2	2.3	0.2	0
PDX	OR	PORTLAND	0	0	0	0.9	20.6	42	169.1	177.1	73.8	1.8	0.1	0
PHL	PA	PHILADELPHIA	0	0	0.5	18.6	93.2	292.7	456.8	381.5	184	33.5	0	0
PHX	AZ	PHOENIX	3	14.8	106.8	270.5	551.9	828.5	972.8	917.5	742.5	397.3	108.4	2
PIA	IL	PEORIA	0	0	4.9	12.7	94.7	257	359.7	318.8	132.2	24.8	0	0
PIH	ID	POCATELLO	0	0	0	0	5	49.3	229.4	161	22.9	1	0	0
PIR	SD	PIERRE	0	0	0.5	2.6	27.8	134.2	354	272.3	87.7	8.6	0	0
PIT	PA	PITTSBURGH	0	0	1	9.7	62.1	164.1	267.3	228.6	79.2	12.7	0	0
PKB	WV	PARKERSBURG	0	0	4.8	19.6	105.2	222.4	311.4	289.1	120.9	20	0.2	0
PNS	FL	PENSACOLA	12	12.2	46.2	127.1	324.6	519.6	556.7	558.2	440.5	195.8	33.2	17.4
PRB	CA	PASO ROBLES	0	0	1.8	14.7	74.6	169.3	314.1	283.7	188.4	41.6	1.9	0
PUB	CO	PUEBLO	0	0	0.9	4.1	44.7	242.3	382.4	310	95.8	7	0	0
PVD	RI	PROVIDENCE	0	0	0.3	2.5	29.7	143.5	323.3	251.1	90.9	11.5	0	0
PWM	ME	PORTLAND	0	0	0	0.5	9.6	61.2	180.9	125.4	37.2	1.6	0	0
RAP	SD	RAPID CITY	0	0	0	1.2	14.6	94	300.7	228.9	67.2	6.8	0	0
RBL	CA	RED BLUFF	0	0	2.7	34.6	162.6	369.1	559.2	485.9	319.4	67.8	5.7	0.1
RDD	CA	REDDING	0	0.3	2.7	29.7	155.4	356.5	573.6	483.1	305.8	59	3.9	0
RDM	OR	REDMOND	0	0	0	0	6.8	18.2	130.4	85.2	17	0	0	0
RDU	NC	RALEIGH DURHAM	1	0.8	12.7	51.8	163.4	383.3	489.7	454.6	250.4	58.5	4.1	2.4
RFD	IL	ROCKFORD	0	0	4.6	4.2	63.7	190.2	291.2	234.3	87.2	17.2	0	0
RIC	VA	RICHMOND	0	0.7	7.3	43.6	143	359.4	485.9	433.2	227.6	54.7	2.4	0.7
RKS	WY	ROCK SPRINGS	0	0	0	0	1.2	51.5	198.4	118.1	11.7	0	0	0
RNO	NV	RENO	0	0	0	3	43.5	174.4	431.7	326.9	132.8	5.3	0	0
ROA	VA	ROANOKE	0	0	7.7	29.3	108.3	288.4	384.7	359.7	154.3	29.6	0.2	0

Station Location			10-year Average Monthly CDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
ROC	NY	ROCHESTER	0	0	0.5	4.2	42.1	132.9	230.1	172.5	59.1	8.4	0	0
ROW	NM	ROSWELL	0	0.2	5	57.5	215.7	487.7	505.4	487.3	247.7	51.8	0	0.1
RSL	KS	RUSSELL	0	0	2.8	18.4	118.1	344.9	486	418.7	164.6	31.6	0.4	0
RST	MN	ROCHESTER	0	0	1.8	1.5	41.4	143.1	230.3	155.4	52.7	13.7	0	0
SAC	CA	SACRAMENTO	0	0	0.5	22.5	96.4	223.6	351	311.5	223.8	45.1	0.2	0
SAN	CA	SAN DIEGO	4	1.4	7	19.3	37.9	66.1	179.6	216.8	191.2	95.8	26.8	1.9
SAT	TX	SAN ANTONIO	11	34.3	93	209.1	395.6	581.8	635.5	694.4	487.6	250.1	76.3	17.4
SAV	GA	SAVANNAH	7	7.4	29.6	111.2	275.2	470.9	548.9	551.9	388.9	154.1	19.7	12.6
SAW	MI	MARQUETTE	0	0	0.3	0	13.3	50.7	113.8	72.5	19.7	3.2	0	0
SBN	IN	SOUTH BEND	0	0	5.2	6.4	64.2	192	275.6	221.1	84.3	16.5	0	0
SBY	MD	SALISBURY	0	0.1	1.6	24.2	96.5	264.8	435.4	344	168.6	42.2	2.2	0.5
SCK	CA	STOCKTON	0	0	2.9	26.1	117.3	250.5	399.3	361.3	243.9	52	1	0
SDF	KY	LOUISVILLE	0	0	13.5	45.7	160.8	367.2	449.5	459.2	229.2	50.1	1.7	0.5
SEA	WA	SEATTLE TACOMA	0	0	0	0.1	8.8	20.6	91.2	90.5	29	0.2	0	0
SFO	CA	SAN FRANCISCO	0	0	0.9	6.3	15.8	23	30.3	31.7	53.3	35.7	1.6	0
SGF	MO	SPRINGFIELD	0	0	9.2	27.6	126.4	327.8	442	438.6	171.1	35.2	0.8	0.2
SHR	WY	SHERIDAN	0	0	0	0.2	4.1	50.6	236.8	176.9	36.7	1.8	0	0
SHV	LA	SHREVEPORT	7	11.7	51	117	301.9	522.3	588.2	638.8	429.9	138.9	32.1	7.7
SIT	AK	SITKA	0	0	0	0	0	0	0.4	0.4	0	0	0	0
SJT	TX	SAN ANGELO	2	9	56.5	163.8	336.1	556.9	592.1	610.3	367	144.7	24.2	3.6
SLC	UT	SALT LAKE CITY	0	0	0.1	4.5	51.8	213.7	516.2	418.1	154.5	9.6	0	0
SLE	OR	SALEM	0	0	0	0.3	13.8	28.3	150.7	145.8	53.8	1.5	0.1	0
SLN	KS	SALINA	0	0	7.1	27.6	145.5	392.6	533.8	473.8	186.6	42	0.9	0
SNP	AK	ST PAUL ISLAND	0	0	0	0	0	0	0	0	0	0	0	0
SPI	IL	SPRINGFIELD	0	0	7.3	21.3	119	279.3	355.7	328.9	137.8	30.5	0.2	0.1
SPS	TX	WICHITA FALLS	2	4.2	36.3	105.8	283.6	542	639.4	661.8	371.9	119.9	16.4	1.6
STC	MN	SAINT CLOUD	0	0	0.7	1.1	31.6	111.8	238.2	153	44.5	5.9	0	0
STL	MO	SAINT LOUIS	0	0.2	15.9	44.4	166.8	389.7	494	472.8	206.6	48.6	2.5	0.8
SUX	IA	SIOUX CITY	0	0	3	10.5	80.3	217.6	339.3	264.2	87	16.3	0.2	0
SYR	NY	SYRACUSE	0	0	0.1	5	45.5	142.8	257.4	191.2	65.2	5.7	0	0
TAD	CO	TRINIDAD	0	0	0.1	2.4	36.8	212.4	332.4	272	100.1	6.4	0	0
TCL	AL	TUSCALOOSA	2	4.8	29.8	84.1	254.5	472.4	528.5	544.8	340.6	95	10.7	5.2
TKA	AK	TALKEETNA	0	0	0	0	0	5.4	7	1.4	0	0	0	0
TLH	FL	TALLAHASSEE	9	10.2	43.8	119.6	321.4	507.6	554.8	568.5	438.8	196.7	27.9	17.1
TOL	OH	TOLEDO	0	0	1.9	6	60.4	192.1	279	226.8	78.3	12	0	0
TOP	KS	TOPEKA	0	0	10.1	27.8	140.6	356.3	479.2	440.8	164.2	37.4	1.9	0
TPA	FL	TAMPA	56	65.3	130.1	258	429.5	528.4	573.9	596	524.5	367.1	141	99.2
TPH	NV	TONOPAH	0	0	0	0.7	31.4	168.4	368	275.4	102.7	8.7	0	0
TRI	TN	BRISTOL	0	0	1.3	12.9	82.6	246.2	319.7	324.4	141.3	16.3	0.1	0
TUL	OK	TULSA	1	1.8	25.2	65.4	205.8	454.2	586.3	578.3	279.9	76.9	8.8	0.7
TUP	MS	TUPELO	1	1.8	24.9	74.8	231	448	518.4	539.3	305.3	80	6.9	1.9
TUS	AZ	TUCSON	1	4.9	43.4	150.8	385.2	664.8	727.7	676.4	537.3	250.4	53	0.4
TVC	MI	TRAVERSE CITY	0	0	2.8	1.7	29	104	196	152.6	46.8	11.2	0	0
TXK	AR	TEXARKANA	4	2.8	37.6	90.1	256.6	478.3	558.6	588.5	343.8	103.2	23.4	4.1
TYS	TN	KNOXVILLE	0	0	9.3	41	149.4	348.9	418.8	429.4	222.5	39.9	1.3	0.4
UCA	NY	UTICA	1	0	4.6	33.9	193.1	368.4	497.8	417.3	204.1	47.3	0.9	0
UIL	WA	QUILLAYUTE	0	0	0	0.2	2.1	3	9.5	6.8	4.8	0	0	0
UIN	IL	QUINCY	0	0	5.4	19.7	102.1	271.4	369.9	343.6	128.2	26.4	0.3	0
VCT	TX	VICTORIA	19	40.7	102.4	208.7	395.3	564.7	611.5	665.3	496.4	265.1	84.8	34.7
VRB	FL	VERO BEACH	72	82.7	122.1	222.4	365.6	472	525.1	548.2	472.2	356.3	171.3	125.6

Station Location			10-year Average Monthly CDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
VTN	NE	VALENTINE	0	0	0.6	2.6	38.1	153.6	355.6	273.4	84	6.5	0	0
VWS	AK	VALDEZ	0	0	0	0	3.8	9	16.2	6.3	0	0	0	0
WMC	NV	WINNEMUCCA	0	0	0	0.3	15.3	81.5	315.5	184	39.3	1.2	0	0
WRL	WY	WORLAND	0	0	0.5	2.5	15.2	100.5	311.8	205.8	40.8	7.3	0	0
YAK	AK	YAKUTAT	0	0	0	0	0	0	0.1	0	0	0	0	0
YKM	WA	YAKIMA	0	0	0	0.4	28.8	75.8	279.2	212.2	50.5	0.9	0	0
YNG	OH	YOUNGSTOWN	0	0	0.8	8.2	47.8	124.6	212.7	166.6	56.4	9	0	0

Table 7C.3.4 Weather Station Monthly Heating Degree Day Data Fractions (10-Year Average)

Station Location			10-year Average Monthly HDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
ABE	PA	ALLENTOWN	20%	18%	14%	7%	3%	0%	0%	0%	1%	6%	12%	17%
ABI	TX	ABILENE	25%	19%	10%	4%	1%	0%	0%	0%	0%	4%	12%	25%
ABQ	NM	ALBUQUERQUE	22%	17%	12%	6%	2%	0%	0%	0%	0%	5%	14%	22%
ABR	SD	ABERDEEN	19%	17%	13%	7%	3%	1%	0%	0%	2%	7%	12%	18%
ABY	GA	ALBANY	26%	20%	12%	3%	0%	0%	0%	0%	0%	3%	14%	22%
ACT	TX	WACO	26%	19%	11%	3%	1%	0%	0%	0%	0%	3%	12%	25%
ACY	NJ	ATLANTIC CITY	20%	18%	15%	8%	3%	0%	0%	0%	1%	5%	12%	17%
ADQ	AK	KODIAK	12%	11%	12%	9%	7%	5%	4%	3%	5%	8%	11%	12%
AGS	GA	AUGUSTA	24%	19%	13%	4%	1%	0%	0%	0%	0%	4%	14%	21%
AHN	GA	ATHENS	24%	19%	12%	5%	1%	0%	0%	0%	0%	5%	14%	21%
AKN	AK	KING SALMON	14%	11%	13%	9%	6%	4%	3%	3%	4%	8%	12%	13%
ALB	NY	ALBANY	20%	17%	14%	8%	3%	1%	0%	0%	2%	7%	12%	17%
ALI	TX	ALICE	30%	21%	9%	1%	0%	0%	0%	0%	0%	1%	10%	28%
ALO	IA	WATERLOO	21%	18%	13%	7%	3%	0%	0%	0%	2%	7%	12%	19%
ALS	CO	ALAMOSA	18%	14%	11%	8%	5%	2%	0%	1%	3%	8%	12%	18%
ALW	WA	WALLA WALLA	18%	15%	12%	8%	4%	1%	0%	0%	1%	7%	14%	20%
AMA	TX	AMARILLO	21%	18%	12%	6%	2%	0%	0%	0%	1%	6%	13%	21%
ANC	AK	ANCHORAGE	15%	12%	12%	8%	5%	3%	2%	2%	4%	9%	13%	14%
ANJ	MI	SAULT ST MARIE	18%	16%	14%	9%	5%	2%	1%	1%	3%	7%	11%	16%
AOO	PA	ALTOONA	19%	17%	14%	7%	3%	1%	0%	0%	2%	7%	12%	17%
APN	MI	ALPENA	18%	16%	14%	9%	5%	1%	0%	1%	3%	7%	11%	16%
ART	NY	WATERTOWN	19%	17%	14%	8%	4%	1%	0%	0%	2%	6%	11%	16%
AST	OR	ASTORIA	13%	12%	12%	10%	7%	5%	3%	2%	4%	7%	11%	14%
ATL	GA	ATLANTA	24%	19%	12%	4%	1%	0%	0%	0%	0%	4%	14%	21%
AUG	ME	AUGUSTA	19%	16%	14%	8%	4%	1%	0%	0%	2%	7%	11%	16%
AUS	TX	AUSTIN	27%	19%	10%	3%	0%	0%	0%	0%	0%	3%	12%	25%
AUW	WI	WAUSAU	19%	17%	13%	8%	4%	1%	0%	0%	2%	7%	12%	17%
AVL	NC	ASHEVILLE	21%	17%	13%	6%	2%	0%	0%	0%	1%	7%	14%	18%
AXN	MN	ALEXANDRIA	20%	17%	13%	7%	3%	1%	0%	0%	2%	7%	12%	18%
AYS	GA	WAYCROSS	27%	20%	11%	3%	0%	1%	0%	0%	0%	3%	13%	22%
BDL	CT	HARTFORD	20%	17%	14%	8%	3%	0%	0%	0%	1%	6%	12%	17%
BDR	CT	BRIDGEPORT	20%	18%	15%	8%	4%	0%	0%	0%	1%	5%	11%	17%
BET	AK	BETHEL	15%	12%	13%	10%	6%	3%	2%	3%	4%	8%	12%	13%
BFD	PA	BRADFORD	17%	16%	14%	8%	5%	2%	1%	1%	3%	7%	11%	15%
BFF	NE	SCOTTSBLUFF	18%	16%	12%	8%	4%	1%	0%	0%	2%	8%	13%	19%
BFL	CA	BAKERSFIELD	25%	17%	11%	6%	1%	0%	0%	0%	0%	2%	13%	25%
BGM	NY	BINGHAMTON	19%	17%	14%	8%	4%	1%	0%	0%	2%	7%	11%	16%
BGR	ME	BANGOR	19%	16%	14%	8%	4%	1%	0%	0%	2%	7%	11%	16%

Station Location			10-year Average Monthly HDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
BHM	AL	BIRMINGHAM	24%	19%	12%	4%	1%	0%	0%	0%	0%	5%	14%	21%
BIL	MT	BILLINGS	17%	15%	12%	9%	5%	1%	0%	0%	2%	8%	13%	18%
BIS	ND	BISMARCK	19%	16%	13%	8%	4%	1%	0%	0%	2%	7%	12%	18%
BKE	OR	BAKER	16%	13%	11%	9%	6%	3%	0%	1%	3%	8%	12%	16%
BKW	WV	BECKLEY	20%	17%	13%	7%	3%	0%	0%	0%	2%	7%	13%	18%
BLH	CA	BLYTHE	30%	19%	7%	1%	0%	0%	0%	0%	0%	0%	9%	34%
BLI	WA	BELLINGHAM	15%	13%	12%	9%	6%	3%	1%	1%	4%	8%	12%	15%
BNA	TN	NASHVILLE	23%	19%	12%	5%	1%	0%	0%	0%	0%	5%	14%	20%
BOI	ID	BOISE	20%	15%	12%	8%	4%	1%	0%	0%	1%	7%	14%	19%
BOS	MA	BOSTON	20%	17%	15%	8%	4%	1%	0%	0%	1%	6%	11%	17%
BQK	GA	BRUNSWICK	27%	21%	12%	4%	0%	0%	0%	0%	0%	3%	13%	21%
BRL	IA	BURLINGTON	22%	19%	13%	6%	2%	0%	0%	0%	1%	6%	12%	19%
BRO	TX	BROWNSVILLE	31%	21%	8%	2%	0%	0%	0%	0%	0%	0%	9%	30%
BTM	MT	BUTTE	15%	13%	11%	9%	6%	3%	1%	1%	4%	8%	12%	16%
BTR	LA	BATON ROUGE	26%	20%	10%	3%	0%	0%	0%	0%	0%	3%	14%	24%
BTV	VT	BURLINGTON	19%	17%	15%	8%	4%	1%	0%	0%	2%	7%	11%	17%
BUF	NY	BUFFALO	19%	18%	15%	9%	4%	1%	0%	0%	2%	6%	11%	16%
BWG	KY	BOWLING GREEN	22%	19%	12%	5%	2%	0%	0%	0%	0%	6%	13%	20%
BWI	MD	BALTIMORE	21%	19%	14%	7%	2%	0%	0%	0%	1%	6%	12%	18%
BYI	ID	BURLEY	18%	14%	12%	9%	5%	2%	0%	0%	2%	8%	12%	17%
CAE	SC	COLUMBIA	24%	19%	13%	4%	1%	0%	0%	0%	0%	4%	14%	21%
CAK	OH	AKRON CANTON	20%	18%	14%	7%	3%	0%	0%	0%	2%	7%	12%	17%
CAO	NM	CLAYTON	19%	17%	13%	8%	3%	0%	0%	0%	1%	6%	12%	20%
CAR	ME	CARIBOU	18%	16%	14%	8%	5%	2%	0%	1%	3%	7%	11%	16%
CDB	AK	COLD BAY	12%	10%	12%	10%	8%	6%	4%	4%	5%	8%	10%	11%
CDC	UT	CEDAR CITY	19%	15%	12%	9%	5%	1%	0%	0%	2%	7%	12%	19%
CDV	AK	CORDOVA	13%	11%	12%	9%	6%	5%	4%	4%	5%	8%	11%	12%
CHA	TN	CHATTANOOGA	24%	19%	12%	5%	1%	0%	0%	0%	0%	5%	14%	21%
CHS	SC	CHARLESTON	26%	20%	13%	4%	0%	0%	0%	0%	0%	3%	13%	20%
CID	IA	CEDAR RAPIDS	21%	18%	13%	7%	3%	0%	0%	0%	2%	7%	12%	19%
CLE	OH	CLEVELAND	20%	18%	14%	8%	3%	0%	0%	0%	1%	6%	12%	17%
CLL	TX	COLLEGE STATIO	28%	20%	10%	3%	0%	0%	0%	0%	0%	2%	12%	26%
CLT	NC	CHARLOTTE	23%	18%	13%	5%	1%	0%	0%	0%	0%	5%	14%	20%
CMH	OH	COLUMBUS	21%	19%	14%	6%	2%	0%	0%	0%	1%	6%	12%	18%
CNK	KS	CONCORDIA	21%	18%	12%	7%	2%	0%	0%	0%	1%	6%	13%	21%
CNM	NM	CARLSBAD	25%	18%	10%	3%	1%	0%	0%	0%	0%	4%	14%	25%
COD	WY	CODY	17%	15%	11%	9%	5%	2%	0%	0%	3%	8%	12%	17%
CON	NH	CONCORD	19%	16%	14%	8%	4%	1%	0%	0%	2%	7%	11%	16%
COS	CO	COLORADO SPRIN	18%	16%	12%	9%	5%	1%	0%	0%	2%	8%	12%	18%
COU	MO	COLUMBIA	22%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	20%
CPR	WY	CASPER	17%	15%	12%	9%	6%	2%	0%	0%	3%	8%	12%	17%
CRP	TX	CORPUS CHRISTI	31%	20%	8%	1%	0%	0%	0%	0%	0%	1%	11%	28%
CRW	WV	CHARLESTON	21%	19%	13%	6%	2%	0%	0%	0%	1%	6%	13%	19%
CSG	GA	COLUMBUS	26%	20%	12%	3%	0%	0%	0%	0%	0%	4%	13%	22%
CSV	TN	CROSSVILLE	22%	18%	13%	6%	2%	0%	0%	0%	1%	6%	13%	19%
CTB	MT	CUT BANK	15%	14%	12%	9%	6%	3%	1%	1%	3%	8%	12%	16%
CVG	OH	CINCINNATI	21%	19%	13%	6%	2%	0%	0%	0%	1%	6%	13%	19%
CXY	PA	HARRISBURG	21%	18%	14%	7%	3%	0%	0%	0%	1%	6%	12%	18%
CYS	WY	CHEYENNE	16%	15%	12%	9%	6%	1%	0%	0%	3%	8%	12%	17%
DAB	FL	DAYTONA BEACH	30%	23%	14%	2%	0%	0%	0%	0%	0%	2%	10%	20%

Station Location			10-year Average Monthly HDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
DAY	OH	DAYTON	21%	18%	13%	7%	3%	0%	0%	0%	1%	6%	12%	18%
DBQ	IA	DUBUQUE	20%	18%	13%	7%	3%	0%	0%	0%	2%	7%	12%	18%
DCA	DC	WASHINGTON	22%	19%	14%	6%	2%	0%	0%	0%	0%	5%	12%	19%
DDC	KS	DODGE CITY	20%	18%	12%	7%	2%	0%	0%	0%	1%	6%	13%	21%
DEN	CO	DENVER	18%	16%	12%	9%	4%	1%	0%	0%	2%	7%	12%	19%
DFW	TX	DALLAS FT WORT	26%	20%	10%	3%	1%	0%	0%	0%	0%	3%	12%	25%
DLH	MN	DULUTH	18%	16%	13%	8%	5%	2%	0%	1%	3%	7%	11%	17%
DRT	TX	DEL RIO	30%	18%	7%	1%	0%	0%	0%	0%	0%	1%	12%	30%
DSM	IA	DES MOINES	22%	18%	13%	6%	2%	0%	0%	0%	1%	6%	12%	20%
DTW	MI	DETROIT	20%	18%	14%	8%	3%	0%	0%	0%	1%	6%	12%	18%
DUG	AZ	DOUGLAS	24%	18%	12%	5%	1%	0%	0%	0%	0%	3%	13%	24%
DUJ	PA	DU BOIS	19%	17%	14%	8%	4%	1%	0%	0%	2%	7%	11%	17%
EAU	WI	EAU CLAIRE	20%	17%	13%	7%	3%	1%	0%	0%	2%	7%	12%	18%
EGE	CO	EAGLE	18%	14%	12%	9%	5%	1%	0%	0%	3%	8%	12%	17%
EKA	CA	EUREKA	12%	10%	11%	10%	8%	6%	5%	5%	6%	7%	9%	11%
EKN	WV	ELKINS	19%	17%	13%	8%	4%	1%	0%	0%	2%	7%	12%	17%
EKO	NV	ELKO	18%	14%	12%	9%	5%	2%	0%	0%	2%	8%	12%	18%
ELP	TX	EL PASO	27%	18%	9%	3%	0%	0%	0%	0%	0%	2%	14%	26%
ELY	NV	ELY	17%	14%	12%	9%	6%	2%	0%	0%	3%	8%	12%	17%
ENA	AK	KENAI	15%	12%	12%	8%	5%	4%	3%	3%	4%	8%	12%	14%
ERI	PA	ERIE	19%	18%	15%	9%	4%	1%	0%	0%	1%	6%	11%	16%
EUG	OR	EUGENE	16%	13%	12%	10%	6%	3%	0%	0%	2%	8%	13%	17%
EVV	IN	EVANSVILLE	22%	19%	13%	6%	2%	0%	0%	0%	1%	6%	13%	20%
EWN	NC	NEW BERN	23%	20%	14%	5%	1%	0%	0%	0%	0%	4%	13%	19%
EWR	NJ	NEWARK	21%	19%	15%	7%	2%	0%	0%	0%	1%	5%	12%	18%
EYW	FL	KEY WEST	45%	24%	8%	0%	0%	0%	5%	0%	0%	0%	1%	17%
FAR	ND	FARGO	20%	17%	13%	7%	3%	1%	0%	0%	2%	6%	12%	18%
FAT	CA	FRESNO	25%	17%	11%	6%	1%	0%	0%	0%	0%	2%	12%	25%
FCA	MT	KALISPELL	17%	14%	11%	8%	4%	2%	0%	1%	3%	8%	14%	18%
FDY	OH	FINDLAY	21%	18%	14%	7%	3%	0%	0%	0%	1%	6%	12%	18%
FLG	AZ	FLAGSTAFF	16%	14%	12%	9%	6%	2%	0%	1%	3%	8%	12%	16%
FLL	FL	FT LAUDERDALE	39%	25%	11%	0%	0%	0%	0%	0%	0%	0%	4%	21%
FLO	SC	FLORENCE	24%	20%	13%	4%	1%	0%	0%	0%	0%	4%	13%	20%
FMY	FL	FORT MYERS	36%	23%	11%	1%	0%	0%	0%	0%	0%	1%	7%	22%
FNT	MI	FLINT	19%	17%	14%	8%	4%	1%	0%	0%	2%	7%	11%	17%
FSD	SD	SIOUX FALLS	20%	17%	13%	7%	3%	0%	0%	0%	2%	7%	12%	19%
FSM	AR	FORT SMITH	24%	19%	11%	4%	1%	0%	0%	0%	0%	4%	12%	23%
FWA	IN	FORT WAYNE	21%	18%	13%	7%	3%	0%	0%	0%	1%	6%	12%	18%
FYV	AR	FAYETTEVILLE	22%	18%	12%	6%	2%	0%	0%	0%	1%	6%	13%	20%
GCK	KS	GARDEN CITY	21%	18%	12%	7%	2%	0%	0%	0%	1%	6%	13%	21%
GEG	WA	SPOKANE	17%	14%	12%	9%	5%	2%	0%	0%	2%	8%	13%	18%
GFK	ND	GRAND FORKS	19%	17%	14%	7%	4%	1%	0%	0%	2%	7%	12%	18%
GFL	NY	GLENS FALLS	19%	17%	14%	8%	4%	1%	0%	0%	3%	7%	11%	16%
GLD	KS	GOODLAND	19%	17%	12%	8%	4%	0%	0%	0%	2%	7%	13%	19%
GLS	TX	GALVESTON	31%	22%	9%	2%	0%	0%	0%	0%	0%	1%	9%	26%
GNV	FL	GAINESVILLE	28%	21%	13%	3%	0%	0%	0%	0%	0%	3%	12%	21%
GRB	WI	GREEN BAY	19%	17%	14%	8%	4%	1%	0%	0%	2%	7%	11%	17%
GRI	NE	GRAND ISLAND	20%	17%	12%	7%	3%	0%	0%	0%	1%	7%	13%	20%
GRR	MI	GRAND RAPIDS	20%	18%	14%	8%	3%	0%	0%	0%	2%	7%	12%	17%
GSO	NC	GREENSBORO	22%	18%	13%	5%	2%	0%	0%	0%	0%	5%	14%	20%

Station Location			10-year Average Monthly HDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
GSP	SC	GREENVILLE	23%	19%	13%	5%	1%	0%	0%	0%	0%	5%	14%	20%
GTF	MT	GREAT FALLS	16%	15%	12%	9%	6%	2%	0%	1%	3%	8%	12%	17%
GUP	NM	GALLUP	18%	14%	12%	9%	5%	1%	0%	0%	2%	8%	13%	18%
GWO	MS	GREENWOOD	24%	20%	12%	4%	1%	0%	0%	0%	0%	5%	13%	22%
HAT	NC	CAPE HATTERAS	27%	24%	17%	5%	1%	0%	0%	0%	0%	1%	7%	17%
HBR	OK	HOBART	23%	19%	11%	6%	1%	0%	0%	0%	0%	4%	12%	23%
HIB	MN	HIBBING	18%	16%	12%	8%	4%	2%	1%	1%	3%	7%	11%	17%
HKY	NC	HICKORY	22%	18%	13%	5%	2%	0%	0%	0%	0%	5%	14%	20%
HLN	MT	HELENA	17%	14%	12%	8%	5%	2%	0%	0%	2%	8%	13%	18%
HNL	HI	HONOLULU-OAHU	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
HOM	AK	HOMER	13%	11%	12%	9%	6%	5%	3%	3%	5%	8%	12%	12%
HON	SD	HURON	20%	17%	13%	7%	3%	1%	0%	0%	2%	7%	12%	19%
HSV	AL	HUNTSVILLE	24%	19%	12%	4%	1%	0%	0%	0%	0%	5%	14%	21%
HTL	MI	HOUGHTON LAKE	18%	16%	14%	8%	4%	1%	1%	1%	3%	7%	11%	16%
HTS	WV	HUNTINGTON	21%	18%	13%	6%	2%	0%	0%	0%	1%	7%	13%	19%
HUL	ME	HOULTON	18%	16%	14%	8%	5%	2%	1%	1%	3%	7%	10%	16%
HVR	MT	HAVRE	17%	15%	12%	8%	4%	2%	0%	0%	3%	7%	12%	18%
IAH	TX	HOUSTON	28%	20%	10%	2%	0%	0%	0%	0%	0%	2%	12%	26%
ICT	KS	WICHITA	22%	18%	12%	6%	2%	0%	0%	0%	0%	5%	13%	22%
IDA	ID	IDAHO FALLS	18%	15%	12%	8%	5%	2%	0%	0%	3%	8%	12%	17%
ILG	DE	WILMINGTON	21%	19%	14%	7%	3%	0%	0%	0%	1%	5%	12%	18%
ILM	NC	WILMINGTON	23%	20%	14%	5%	1%	0%	0%	0%	0%	4%	13%	19%
IND	IN	INDIANAPOLIS	21%	19%	13%	6%	2%	0%	0%	0%	1%	6%	12%	19%
INL	MN	INT'L FALLS	18%	16%	13%	8%	4%	2%	1%	1%	3%	7%	11%	17%
INW	AZ	WINSLOW	22%	16%	12%	7%	2%	0%	0%	0%	0%	6%	13%	21%
IPT	PA	WILLIAMSPORT	20%	18%	14%	7%	3%	0%	0%	0%	1%	6%	12%	18%
ISN	ND	WILLISTON	18%	16%	13%	7%	4%	1%	0%	0%	2%	7%	12%	18%
ITO	HI	HILO-HAWAII	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
JAX	FL	JACKSONVILLE	27%	21%	13%	3%	0%	0%	0%	0%	0%	3%	13%	21%
JKL	KY	JACKSON	22%	19%	13%	5%	2%	0%	0%	0%	1%	6%	12%	19%
JLN	MO	JOPLIN	22%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	21%
JNU	AK	JUNEAU	13%	12%	12%	9%	6%	4%	3%	3%	5%	8%	12%	13%
JXN	MI	JACKSON	19%	17%	14%	8%	3%	1%	0%	0%	2%	7%	11%	17%
KTN	AK	KETCHIKAN	13%	12%	12%	10%	7%	4%	3%	3%	5%	8%	11%	13%
LAF	IN	WEST LAFAYETTE	21%	18%	13%	7%	3%	0%	0%	0%	1%	6%	12%	19%
LAN	MI	LANSING	19%	17%	14%	8%	4%	1%	0%	0%	2%	7%	12%	17%
LAS	NV	LAS VEGAS	27%	19%	9%	3%	0%	0%	0%	0%	0%	1%	11%	29%
LAX	CA	LOS ANGELES	18%	18%	16%	11%	5%	1%	0%	0%	0%	3%	8%	20%
LBB	TX	LUBBOCK	23%	18%	11%	5%	2%	0%	0%	0%	0%	5%	13%	23%
LBF	NE	NORTH PLATTE	19%	16%	12%	8%	4%	0%	0%	0%	2%	8%	13%	19%
LCH	LA	LAKE CHARLES	27%	20%	10%	2%	0%	0%	0%	0%	0%	2%	13%	24%
LEB	NH	LEBANON	19%	17%	14%	8%	4%	1%	0%	0%	2%	7%	11%	16%
LEX	KY	LEXINGTON	21%	18%	13%	6%	2%	0%	0%	0%	1%	6%	13%	19%
LFK	TX	LUFKIN	26%	19%	10%	3%	0%	0%	0%	0%	0%	3%	13%	24%
LFT	LA	LAFAYETTE	27%	20%	10%	2%	0%	0%	0%	0%	0%	3%	13%	24%
LGA	NY	NEW YORK	22%	19%	16%	8%	3%	0%	0%	0%	0%	4%	11%	18%
LIH	HI	LIHUE-KAUAI	0%	0%	100%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LIT	AR	LITTLE ROCK	24%	19%	12%	4%	1%	0%	0%	0%	0%	4%	13%	22%
LND	WY	LANDER	18%	15%	11%	9%	5%	1%	0%	0%	2%	8%	12%	18%
LNK	NE	LINCOLN	21%	18%	12%	7%	2%	0%	0%	0%	1%	6%	12%	20%

Station Location			10-year Average Monthly HDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
LOL	NV	LOVELOCK	20%	14%	12%	8%	3%	1%	0%	0%	1%	7%	14%	20%
LRD	TX	LAREDO	32%	20%	6%	1%	0%	0%	0%	0%	0%	1%	10%	31%
LSE	WI	LACROSSE	21%	18%	13%	7%	3%	0%	0%	0%	2%	6%	12%	19%
LWS	ID	LEWISTON	18%	15%	12%	8%	4%	1%	0%	0%	1%	8%	14%	19%
LWT	MT	LEWISTOWN	15%	14%	12%	9%	6%	3%	0%	1%	3%	8%	12%	16%
LYH	VA	LYNCHBURG	21%	18%	13%	6%	2%	0%	0%	0%	1%	6%	13%	19%
MAF	TX	MIDLAND ODESSA	25%	19%	10%	3%	1%	0%	0%	0%	0%	4%	14%	24%
MBS	MI	SAGINAW	19%	17%	14%	8%	4%	1%	0%	0%	2%	7%	11%	17%
MCB	MS	MCCOMB	26%	20%	11%	3%	1%	0%	0%	0%	0%	4%	14%	22%
MCI	MO	KANSAS CITY	22%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	20%
MCN	GA	MACON	24%	19%	12%	4%	1%	0%	0%	0%	0%	4%	15%	21%
MCO	FL	ORLANDO	32%	23%	12%	1%	0%	0%	0%	0%	0%	2%	9%	21%
MCW	IA	MASON CITY	20%	17%	13%	7%	3%	0%	0%	0%	2%	7%	12%	18%
MEM	TN	MEMPHIS	24%	20%	12%	4%	1%	0%	0%	0%	0%	4%	13%	22%
MFD	OH	MANSFIELD	20%	18%	14%	7%	3%	1%	0%	0%	2%	7%	12%	17%
MFE	TX	MCALLEN	31%	21%	6%	2%	0%	0%	0%	0%	0%	0%	10%	29%
MFR	OR	MEDFORD	19%	14%	13%	9%	4%	1%	0%	0%	1%	7%	14%	19%
MGM	AL	MONTGOMERY	25%	19%	11%	3%	1%	0%	0%	0%	0%	4%	15%	22%
MGW	WV	MORGANTOWN	20%	18%	14%	7%	3%	0%	0%	0%	1%	7%	12%	18%
MHS	CA	MT SHASTA	16%	14%	13%	10%	6%	2%	0%	0%	2%	8%	12%	17%
MIA	FL	MIAMI	40%	25%	10%	0%	0%	0%	0%	0%	0%	0%	4%	20%
MKE	WI	MILWAUKEE	19%	17%	14%	8%	4%	1%	0%	0%	2%	6%	11%	17%
MKG	MI	MUSKEGON	19%	17%	14%	8%	4%	1%	0%	0%	2%	7%	11%	16%
MKL	TN	JACKSON	23%	19%	12%	5%	1%	0%	0%	0%	0%	6%	14%	20%
MLB	FL	MELBOURNE	32%	23%	14%	2%	0%	0%	0%	0%	0%	2%	8%	20%
MLC	OK	MCALESTER	24%	19%	11%	5%	1%	0%	0%	0%	0%	5%	12%	23%
MLI	IL	MOLINE	21%	18%	13%	6%	2%	0%	0%	0%	1%	6%	12%	19%
MLS	MT	MILES CITY	18%	16%	12%	8%	4%	1%	0%	0%	2%	7%	13%	19%
MLU	LA	MONROE	25%	20%	11%	3%	1%	0%	0%	0%	0%	4%	14%	23%
MOB	AL	MOBILE	26%	20%	11%	3%	0%	0%	0%	0%	0%	4%	14%	22%
MOT	ND	MINOT	18%	16%	13%	8%	4%	1%	0%	0%	2%	7%	12%	18%
MPV	VT	MONTPELIER	18%	16%	14%	8%	4%	1%	0%	1%	3%	7%	11%	16%
MRB	WV	MARTINSBURG	20%	18%	14%	7%	3%	0%	0%	0%	1%	6%	12%	18%
MSL	AL	MUSCLE SHOALS	24%	19%	12%	5%	1%	0%	0%	0%	0%	5%	14%	21%
MSN	WI	MADISON	20%	17%	13%	7%	3%	0%	0%	0%	2%	7%	12%	18%
MSO	MT	MISSOULA	17%	14%	11%	9%	5%	2%	0%	0%	3%	8%	13%	18%
MSP	MN	MINNEAPOLIS	21%	18%	13%	7%	3%	0%	0%	0%	2%	6%	12%	19%
MSS	NY	MASSENA	19%	17%	14%	8%	4%	1%	0%	0%	2%	7%	11%	17%
MSY	LA	NEW ORLEANS	29%	21%	10%	2%	0%	0%	0%	0%	0%	2%	12%	24%
NYL	AZ	YUMA	27%	20%	7%	2%	0%	0%	0%	0%	0%	0%	7%	37%
OFK	NE	NORFOLK	20%	17%	12%	7%	3%	0%	0%	0%	2%	7%	12%	20%
OGG	HI	KAHULUI-MAUI	0%	50%	50%	0%	0%	0%	0%	0%	0%	0%	0%	0%
OKC	OK	OKLAHOMA CITY	23%	19%	11%	5%	1%	0%	0%	0%	0%	4%	12%	23%
OLM	WA	OLYMPIA	15%	13%	12%	10%	6%	3%	1%	1%	3%	8%	12%	15%
OMA	NE	OMAHA	21%	18%	12%	6%	2%	0%	0%	0%	1%	6%	12%	20%
ORD	IL	CHICAGO	20%	18%	13%	7%	3%	0%	0%	0%	1%	6%	12%	18%
ORF	VA	NORFOLK	23%	20%	15%	6%	2%	0%	0%	0%	0%	4%	12%	19%
ORH	MA	WORCESTER	19%	17%	14%	8%	4%	1%	0%	0%	2%	7%	11%	17%
OTM	IA	OTTUMWA	21%	18%	12%	7%	3%	0%	0%	0%	2%	6%	12%	19%
P11	ND	DEVIL'S LAKE	19%	17%	14%	8%	4%	1%	0%	0%	2%	7%	12%	18%

Station Location			10-year Average Monthly HDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
PAH	KY	PADUCAH	22%	18%	12%	6%	2%	0%	0%	0%	1%	6%	13%	20%
PBI	FL	WEST PALM BEAC	36%	24%	13%	1%	0%	0%	0%	0%	0%	1%	6%	19%
PDT	OR	PENDLETON	17%	14%	12%	9%	5%	2%	0%	0%	2%	8%	14%	19%
PDX	OR	PORTLAND	17%	14%	12%	9%	5%	2%	0%	0%	1%	7%	13%	18%
PHL	PA	PHILADELPHIA	22%	19%	15%	7%	2%	0%	0%	0%	0%	5%	12%	18%
PHX	AZ	PHOENIX	31%	19%	7%	1%	0%	0%	0%	0%	0%	0%	7%	35%
PIA	IL	PEORIA	21%	19%	13%	6%	2%	0%	0%	0%	1%	6%	12%	19%
PIH	ID	POCATELLO	18%	15%	12%	8%	5%	2%	0%	0%	2%	8%	12%	17%
PIR	SD	PIERRE	19%	17%	13%	8%	4%	1%	0%	0%	2%	7%	12%	19%
PIT	PA	PITTSBURGH	20%	18%	14%	7%	3%	0%	0%	0%	1%	7%	12%	17%
PKB	WV	PARKERSBURG	21%	18%	13%	6%	2%	0%	0%	0%	1%	7%	13%	18%
PNS	FL	PENSACOLA	27%	21%	11%	2%	0%	0%	0%	0%	0%	3%	13%	23%
PRB	CA	PASO ROBLES	20%	16%	13%	9%	3%	1%	0%	0%	1%	5%	12%	21%
PUB	CO	PUEBLO	19%	17%	12%	8%	3%	0%	0%	0%	1%	7%	13%	20%
PVD	RI	PROVIDENCE	20%	17%	15%	8%	4%	1%	0%	0%	1%	6%	11%	17%
PWM	ME	PORTLAND	19%	16%	14%	9%	5%	1%	0%	0%	2%	6%	11%	16%
RAP	SD	RAPID CITY	17%	16%	12%	9%	5%	1%	0%	0%	2%	8%	12%	18%
RBL	CA	RED BLUFF	21%	16%	13%	8%	2%	0%	0%	0%	0%	3%	13%	23%
RDD	CA	REDDING	21%	16%	14%	8%	2%	0%	0%	0%	0%	4%	14%	22%
RDM	OR	REDMOND	15%	13%	12%	10%	6%	3%	1%	1%	3%	8%	12%	16%
RDU	NC	RALEIGH DURHAM	23%	19%	14%	5%	1%	0%	0%	0%	0%	5%	14%	20%
RFD	IL	ROCKFORD	21%	18%	13%	7%	3%	0%	0%	0%	1%	6%	12%	19%
RIC	VA	RICHMOND	22%	19%	14%	6%	2%	0%	0%	0%	0%	5%	12%	19%
RKS	WY	ROCK SPRINGS	17%	14%	12%	9%	6%	2%	0%	0%	3%	8%	12%	17%
RNO	NV	RENO	19%	15%	12%	9%	4%	1%	0%	0%	1%	7%	13%	20%
ROA	VA	ROANOKE	21%	18%	13%	6%	2%	0%	0%	0%	1%	6%	13%	19%
ROC	NY	ROCHESTER	19%	17%	15%	8%	4%	1%	0%	0%	2%	6%	11%	16%
ROW	NM	ROSWELL	24%	17%	11%	4%	1%	0%	0%	0%	0%	4%	14%	24%
RSL	KS	RUSSELL	21%	18%	12%	7%	2%	0%	0%	0%	1%	6%	13%	21%
RST	MN	ROCHESTER	20%	17%	13%	7%	3%	0%	0%	0%	2%	6%	12%	18%
SAC	CA	SACRAMENTO	23%	16%	13%	8%	2%	0%	0%	0%	0%	3%	13%	22%
SAN	CA	SAN DIEGO	21%	18%	14%	10%	4%	1%	0%	0%	0%	1%	8%	22%
SAT	TX	SAN ANTONIO	29%	19%	9%	2%	0%	0%	0%	0%	0%	2%	12%	27%
SAV	GA	SAVANNAH	26%	20%	13%	4%	0%	0%	0%	0%	0%	3%	13%	20%
SAW	MI	MARQUETTE	17%	15%	13%	9%	5%	2%	1%	1%	3%	7%	11%	16%
SBN	IN	SOUTH BEND	20%	18%	14%	7%	3%	0%	0%	0%	2%	6%	12%	18%
SBY	MD	SALISBURY	21%	19%	15%	7%	3%	0%	0%	0%	1%	5%	12%	18%
SCK	CA	STOCKTON	24%	16%	12%	7%	2%	0%	0%	0%	0%	3%	13%	23%
SDF	KY	LOUISVILLE	23%	19%	13%	5%	2%	0%	0%	0%	0%	5%	13%	20%
SEA	WA	SEATTLE TACOMA	16%	13%	13%	10%	6%	3%	1%	1%	2%	8%	13%	16%
SFO	CA	SAN FRANCISCO	17%	13%	12%	10%	7%	4%	2%	2%	2%	4%	10%	17%
SGF	MO	SPRINGFIELD	22%	18%	12%	6%	2%	0%	0%	0%	1%	6%	12%	20%
SHR	WY	SHERIDAN	17%	15%	12%	9%	5%	2%	0%	0%	3%	8%	12%	18%
SHV	LA	SHREVEPORT	25%	20%	11%	3%	1%	0%	0%	0%	0%	3%	13%	24%
SIT	AK	SITKA	12%	11%	12%	10%	7%	5%	4%	3%	5%	8%	11%	12%
SJT	TX	SAN ANGELO	26%	19%	10%	3%	1%	0%	0%	0%	0%	4%	13%	25%
SLC	UT	SALT LAKE CITY	21%	15%	12%	8%	4%	1%	0%	0%	1%	6%	13%	20%
SLE	OR	SALEM	16%	14%	12%	10%	6%	3%	0%	0%	2%	7%	13%	17%
SLN	KS	SALINA	22%	18%	12%	6%	2%	0%	0%	0%	1%	6%	12%	21%
SNP	AK	ST PAUL ISLAND	12%	11%	12%	10%	8%	6%	5%	4%	5%	7%	9%	10%

Station Location			10-year Average Monthly HDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
SPI	IL	SPRINGFIELD	22%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	20%
SPS	TX	WICHITA FALLS	24%	19%	11%	4%	1%	0%	0%	0%	0%	4%	12%	24%
STC	MN	SAINT CLOUD	20%	17%	13%	7%	3%	1%	0%	0%	2%	7%	12%	18%
STL	MO	SAINT LOUIS	23%	19%	12%	5%	2%	0%	0%	0%	1%	5%	12%	20%
SUX	IA	SIOUX CITY	21%	17%	12%	7%	2%	0%	0%	0%	2%	7%	12%	20%
SYR	NY	SYRACUSE	19%	18%	15%	8%	4%	1%	0%	0%	2%	6%	11%	17%
TAD	CO	TRINIDAD	19%	16%	12%	8%	4%	0%	0%	0%	1%	7%	13%	19%
TCL	AL	TUSCALOOSA	25%	20%	11%	4%	1%	0%	0%	0%	0%	5%	14%	21%
TKA	AK	TALKEETNA	15%	12%	12%	8%	5%	2%	2%	2%	5%	9%	13%	14%
TLH	FL	TALLAHASSEE	26%	21%	12%	3%	0%	0%	0%	0%	0%	3%	14%	21%
TOL	OH	TOLEDO	20%	18%	14%	7%	3%	0%	0%	0%	2%	6%	12%	17%
TOP	KS	TOPEKA	22%	18%	12%	6%	2%	0%	0%	0%	1%	6%	12%	21%
TPA	FL	TAMPA	33%	23%	12%	1%	0%	0%	0%	0%	0%	1%	8%	22%
TPH	NV	TONOPAH	18%	15%	13%	9%	4%	1%	0%	0%	1%	7%	13%	19%
TRI	TN	BRISTOL	21%	18%	13%	6%	2%	0%	0%	0%	1%	6%	14%	19%
TUL	OK	TULSA	23%	19%	11%	5%	1%	0%	0%	0%	0%	5%	12%	23%
TUP	MS	TUPELO	24%	19%	12%	4%	1%	0%	0%	0%	0%	5%	14%	21%
TUS	AZ	TUCSON	28%	20%	10%	3%	0%	0%	0%	0%	0%	1%	9%	29%
TVC	MI	TRAVERSE CITY	18%	17%	14%	9%	5%	1%	0%	0%	2%	7%	11%	16%
TXK	AR	TEXARKANA	25%	19%	11%	4%	1%	0%	0%	0%	0%	4%	13%	23%
TYS	TN	KNOXVILLE	23%	18%	13%	5%	2%	0%	0%	0%	0%	6%	14%	20%
UCA	NY	UTICA	22%	19%	15%	6%	2%	0%	0%	0%	1%	5%	11%	19%
UIL	WA	QUILLAYUTE	13%	11%	12%	10%	7%	5%	3%	3%	4%	8%	11%	13%
UIN	IL	QUINCY	21%	19%	12%	6%	2%	0%	0%	0%	1%	6%	12%	19%
VCT	TX	VICTORIA	29%	20%	10%	2%	0%	0%	0%	0%	0%	2%	12%	26%
VRB	FL	VERO BEACH	32%	23%	14%	2%	0%	0%	0%	0%	0%	1%	8%	19%
VTN	NE	VALENTINE	18%	16%	12%	8%	4%	1%	0%	0%	2%	7%	13%	19%
VWS	AK	VALDEZ	16%	13%	13%	9%	5%	2%	1%	2%	4%	8%	13%	14%
WMC	NV	WINNEMUCCA	18%	13%	12%	9%	5%	2%	0%	0%	2%	8%	13%	18%
WRL	WY	WORLAND	19%	16%	11%	7%	4%	1%	0%	0%	2%	7%	13%	19%
YAK	AK	YAKUTAT	13%	11%	12%	9%	7%	5%	3%	4%	5%	8%	11%	12%
YKM	WA	YAKIMA	18%	14%	12%	8%	4%	1%	0%	0%	2%	8%	14%	19%
YNG	OH	YOUNGSTOWN	19%	18%	14%	8%	4%	1%	0%	0%	2%	7%	12%	17%

Table 7C.3.5 Weather Station Monthly Cooling Degree Day Data Fractions (10-Year Average)

Station Location			10-year Average Monthly CDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
ABE	PA	ALLENTOWN	0%	0%	0%	1%	6%	21%	35%	26%	10%	1%	0%	0%
ABI	TX	ABILENE	0%	0%	2%	5%	11%	19%	22%	22%	13%	5%	1%	0%
ABQ	NM	ALBUQUERQUE	0%	0%	0%	1%	7%	24%	30%	25%	12%	1%	0%	0%
ABR	SD	ABERDEEN	0%	0%	0%	0%	4%	18%	42%	27%	8%	1%	0%	0%
ABY	GA	ALBANY	0%	0%	1%	4%	12%	19%	21%	21%	15%	6%	1%	0%
ACT	TX	WACO	0%	0%	2%	4%	10%	18%	21%	22%	14%	6%	1%	0%
ACY	NJ	ATLANTIC CITY	0%	0%	0%	1%	5%	19%	33%	27%	12%	2%	0%	0%
ADQ	AK	KODIAK	0%	0%	0%	0%	18%	35%	47%	0%	0%	0%	0%	0%
AGS	GA	AUGUSTA	0%	0%	1%	3%	10%	20%	24%	24%	15%	4%	0%	0%
AHN	GA	ATHENS	0%	0%	1%	3%	9%	21%	25%	24%	14%	3%	0%	0%
AKN	AK	KING SALMON	0%	0%	0%	0%	0%	0%	56%	44%	0%	0%	0%	0%
ALB	NY	ALBANY	0%	0%	0%	1%	5%	20%	37%	27%	9%	1%	0%	0%

Station Location			10-year Average Monthly CDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
ALI	TX	ALICE	1%	2%	4%	7%	12%	15%	16%	17%	13%	8%	3%	2%
ALO	IA	WATERLOO	0%	0%	0%	1%	7%	22%	34%	26%	8%	2%	0%	0%
ALS	CO	ALAMOSA	0%	0%	0%	0%	0%	13%	59%	26%	2%	0%	0%	0%
ALW	WA	WALLA WALLA	0%	0%	0%	0%	5%	10%	39%	34%	12%	1%	0%	0%
AMA	TX	AMARILLO	0%	0%	0%	2%	9%	23%	27%	26%	12%	2%	0%	0%
ANC	AK	ANCHORAGE	0%	0%	0%	0%	0%	24%	72%	4%	0%	0%	0%	0%
ANJ	MI	SAULT ST MARIE	0%	0%	0%	0%	4%	15%	41%	31%	7%	1%	0%	0%
AOO	PA	ALTOONA	0%	0%	0%	1%	7%	21%	34%	25%	9%	2%	0%	0%
APN	MI	ALPENA	0%	0%	0%	0%	4%	20%	39%	28%	7%	2%	0%	0%
ART	NY	WATERTOWN	0%	0%	0%	0%	5%	18%	34%	30%	10%	1%	0%	0%
AST	OR	ASTORIA	0%	0%	0%	1%	16%	6%	22%	22%	33%	0%	0%	0%
ATL	GA	ATLANTA	0%	0%	1%	3%	10%	20%	23%	24%	15%	4%	0%	0%
AUG	ME	AUGUSTA	0%	0%	0%	0%	3%	15%	43%	29%	8%	1%	0%	0%
AUS	TX	AUSTIN	0%	1%	2%	5%	11%	18%	19%	21%	14%	6%	2%	0%
AUW	WI	WAUSAU	0%	0%	0%	0%	6%	20%	39%	27%	7%	1%	0%	0%
AVL	NC	ASHEVILLE	0%	0%	0%	1%	6%	22%	30%	29%	11%	1%	0%	0%
AXN	MN	ALEXANDRIA	0%	0%	0%	0%	5%	17%	42%	28%	8%	1%	0%	0%
AYS	GA	WAYCROSS	0%	1%	2%	6%	12%	17%	20%	20%	15%	6%	1%	1%
BDL	CT	HARTFORD	0%	0%	0%	1%	5%	19%	37%	27%	10%	1%	0%	0%
BDR	CT	BRIDGEPORT	0%	0%	0%	0%	3%	17%	36%	30%	12%	2%	0%	0%
BET	AK	BETHEL	0%	0%	0%	0%	0%	34%	59%	7%	0%	0%	0%	0%
BFD	PA	BRADFORD	0%	0%	0%	0%	7%	21%	39%	23%	9%	1%	0%	0%
BFF	NE	SCOTTSBLUFF	0%	0%	0%	0%	3%	18%	39%	30%	8%	0%	0%	0%
BFL	CA	BAKERSFIELD	0%	0%	0%	3%	9%	17%	26%	24%	16%	4%	0%	0%
BGM	NY	BINGHAMTON	0%	0%	0%	1%	6%	20%	38%	25%	9%	1%	0%	0%
BGR	ME	BANGOR	0%	0%	0%	0%	2%	14%	47%	29%	8%	0%	0%	0%
BHM	AL	BIRMINGHAM	0%	0%	1%	4%	10%	20%	23%	23%	14%	4%	0%	0%
BIL	MT	BILLINGS	0%	0%	0%	0%	2%	11%	44%	33%	9%	1%	0%	0%
BIS	ND	BISMARCK	0%	0%	0%	0%	3%	15%	44%	30%	8%	0%	0%	0%
BKE	OR	BAKER	0%	0%	0%	0%	3%	6%	52%	34%	5%	0%	0%	0%
BKW	WV	BECKLEY	0%	0%	0%	2%	7%	20%	31%	29%	10%	1%	0%	0%
BLH	CA	BLYTHE	0%	0%	2%	5%	11%	16%	21%	20%	15%	7%	1%	0%
BLI	WA	BELLINGHAM	0%	0%	0%	0%	1%	7%	44%	44%	4%	0%	0%	0%
BNA	TN	NASHVILLE	0%	0%	1%	3%	9%	21%	25%	26%	13%	3%	0%	0%
BOI	ID	BOISE	0%	0%	0%	0%	4%	12%	40%	32%	12%	1%	0%	0%
BOS	MA	BOSTON	0%	0%	0%	1%	4%	17%	37%	29%	11%	1%	0%	0%
BQK	GA	BRUNSWICK	0%	1%	2%	5%	11%	17%	20%	21%	15%	7%	1%	1%
BRL	IA	BURLINGTON	0%	0%	0%	2%	8%	22%	29%	26%	11%	2%	0%	0%
BRO	TX	BROWNSVILLE	2%	3%	5%	8%	11%	14%	15%	15%	12%	9%	4%	2%
BTM	MT	BUTTE	0%	0%	0%	0%	0%	9%	62%	27%	1%	0%	0%	0%
BTR	LA	BATON ROUGE	1%	1%	2%	5%	11%	18%	19%	20%	15%	6%	1%	1%
BTV	VT	BURLINGTON	0%	0%	0%	1%	5%	20%	38%	28%	9%	1%	0%	0%
BUF	NY	BUFFALO	0%	0%	0%	0%	6%	20%	35%	28%	10%	1%	0%	0%
BWG	KY	BOWLING GREEN	0%	0%	1%	3%	9%	21%	26%	26%	12%	2%	0%	0%
BWI	MD	BALTIMORE	0%	0%	0%	2%	7%	21%	31%	26%	11%	2%	0%	0%
BYI	ID	BURLEY	0%	0%	0%	0%	2%	11%	49%	34%	4%	1%	0%	0%
CAE	SC	COLUMBIA	0%	0%	1%	4%	10%	20%	23%	23%	15%	4%	0%	0%
CAK	OH	AKRON CANTON	0%	0%	0%	1%	8%	20%	33%	27%	9%	2%	0%	0%
CAO	NM	CLAYTON	0%	0%	0%	1%	6%	23%	31%	27%	11%	1%	0%	0%
CAR	ME	CARIBOU	0%	0%	0%	0%	2%	17%	48%	27%	5%	0%	0%	0%

Station Location			10-year Average Monthly CDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
CDB	AK	COLD BAY	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
CDC	UT	CEDAR CITY	0%	0%	0%	0%	1%	17%	45%	31%	6%	0%	0%	0%
CDV	AK	CORDOVA	0%	0%	0%	0%	0%	#####	0%	0%	0%	0%	0%	0%
CHA	TN	CHATTANOOGA	0%	0%	1%	3%	9%	21%	24%	25%	14%	3%	0%	0%
CHS	SC	CHARLESTON	0%	0%	1%	4%	11%	19%	22%	22%	15%	6%	1%	0%
CID	IA	CEDAR RAPIDS	0%	0%	0%	1%	7%	22%	32%	26%	9%	2%	0%	0%
CLE	OH	CLEVELAND	0%	0%	0%	1%	8%	21%	32%	27%	9%	2%	0%	0%
CLL	TX	COLLEGE STATIO	0%	1%	2%	5%	11%	17%	19%	20%	15%	7%	2%	1%
CLT	NC	CHARLOTTE	0%	0%	1%	2%	9%	21%	26%	25%	14%	3%	0%	0%
CMH	OH	COLUMBUS	0%	0%	0%	1%	9%	21%	29%	27%	11%	2%	0%	0%
CNK	KS	CONCORDIA	0%	0%	0%	1%	7%	22%	31%	26%	10%	2%	0%	0%
CNM	NM	CARLSBAD	0%	0%	1%	4%	12%	23%	22%	22%	12%	3%	0%	0%
COD	WY	CODY	0%	0%	0%	0%	2%	11%	46%	31%	8%	1%	0%	0%
CON	NH	CONCORD	0%	0%	0%	0%	4%	19%	41%	27%	9%	0%	0%	0%
COS	CO	COLORADO SPRIN	0%	0%	0%	0%	3%	22%	39%	28%	8%	0%	0%	0%
COU	MO	COLUMBIA	0%	0%	1%	2%	8%	21%	29%	27%	10%	2%	0%	0%
CPR	WY	CASPER	0%	0%	0%	0%	1%	12%	48%	32%	6%	0%	0%	0%
CRP	TX	CORPUS CHRISTI	1%	2%	4%	7%	11%	15%	16%	17%	14%	9%	3%	2%
CRW	WV	CHARLESTON	0%	0%	1%	3%	8%	21%	28%	27%	12%	2%	0%	0%
CSG	GA	COLUMBUS	0%	0%	1%	4%	11%	19%	22%	22%	15%	5%	1%	0%
CSV	TN	CROSSVILLE	0%	0%	0%	2%	8%	20%	27%	28%	12%	2%	0%	0%
CTB	MT	CUT BANK	0%	0%	0%	0%	2%	6%	51%	35%	7%	0%	0%	0%
CVG	OH	CINCINNATI	0%	0%	1%	1%	8%	20%	28%	28%	12%	2%	0%	0%
CXY	PA	HARRISBURG	0%	0%	0%	1%	7%	21%	33%	26%	11%	2%	0%	0%
CYS	WY	CHEYENNE	0%	0%	0%	0%	1%	15%	45%	32%	7%	0%	0%	0%
DAB	FL	DAYTONA BEACH	1%	1%	2%	6%	11%	15%	17%	18%	15%	9%	3%	2%
DAY	OH	DAYTON	0%	0%	0%	1%	8%	21%	30%	27%	10%	2%	0%	0%
DBQ	IA	DUBUQUE	0%	0%	0%	1%	6%	22%	34%	26%	9%	2%	0%	0%
DCA	DC	WASHINGTON	0%	0%	0%	2%	7%	20%	29%	26%	13%	3%	0%	0%
DDC	KS	DODGE CITY	0%	0%	0%	1%	7%	21%	30%	27%	11%	2%	0%	0%
DEN	CO	DENVER	0%	0%	0%	0%	3%	19%	38%	30%	10%	1%	0%	0%
DFW	TX	DALLAS FT WORT	0%	0%	2%	4%	10%	18%	21%	23%	14%	5%	1%	0%
DLH	MN	DULUTH	0%	0%	0%	0%	2%	12%	48%	29%	7%	0%	0%	0%
DRT	TX	DEL RIO	0%	1%	3%	7%	12%	17%	18%	19%	13%	7%	2%	0%
DSM	IA	DES MOINES	0%	0%	0%	1%	7%	21%	32%	27%	10%	2%	0%	0%
DTW	MI	DETROIT	0%	0%	0%	0%	7%	21%	33%	28%	9%	1%	0%	0%
DUG	AZ	DOUGLAS	0%	0%	0%	2%	9%	23%	25%	22%	15%	4%	0%	0%
DUJ	PA	DU BOIS	0%	0%	0%	1%	8%	19%	35%	26%	8%	2%	0%	0%
EAU	WI	EAU CLAIRE	0%	0%	0%	0%	6%	20%	38%	27%	8%	1%	0%	0%
EGE	CO	EAGLE	0%	0%	0%	0%	1%	13%	56%	27%	3%	0%	0%	0%
EKA	CA	EUREKA	0%	0%	0%	5%	10%	0%	3%	32%	25%	20%	5%	0%
EKN	WV	ELKINS	0%	0%	0%	0%	5%	19%	34%	32%	9%	1%	0%	0%
EKO	NV	ELKO	0%	0%	0%	0%	1%	11%	51%	31%	5%	0%	0%	0%
ELP	TX	EL PASO	0%	0%	1%	5%	12%	23%	22%	20%	13%	4%	0%	0%
ELY	NV	ELY	0%	0%	0%	0%	0%	10%	55%	31%	3%	0%	0%	0%
ENA	AK	KENAI	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
ERI	PA	ERIE	0%	0%	0%	1%	6%	20%	33%	28%	11%	2%	0%	0%
EUG	OR	EUGENE	0%	0%	0%	0%	2%	5%	40%	39%	13%	0%	0%	0%
EVV	IN	EVANSVILLE	0%	0%	1%	2%	9%	22%	26%	26%	12%	2%	0%	0%
EWN	NC	NEW BERN	0%	0%	1%	3%	9%	19%	24%	24%	14%	5%	0%	0%

Station Location			10-year Average Monthly CDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
EWR	NJ	NEWARK	0%	0%	0%	1%	6%	19%	33%	27%	12%	2%	0%	0%
EYW	FL	KEY WEST	4%	4%	5%	8%	10%	11%	13%	13%	11%	10%	6%	5%
FAR	ND	FARGO	0%	0%	0%	0%	6%	20%	39%	26%	9%	1%	0%	0%
FAT	CA	FRESNO	0%	0%	0%	2%	9%	17%	26%	24%	17%	5%	0%	0%
FCA	MT	KALISPELL	0%	0%	0%	1%	5%	14%	38%	31%	9%	1%	0%	0%
FDY	OH	FINDLAY	0%	0%	0%	1%	9%	23%	31%	25%	10%	2%	0%	0%
FLG	AZ	FLAGSTAFF	0%	0%	0%	0%	0%	16%	57%	26%	1%	0%	0%	0%
FLL	FL	FT LAUDERDALE	4%	4%	5%	8%	10%	12%	13%	13%	12%	10%	6%	5%
FLO	SC	FLORENCE	0%	0%	1%	4%	10%	20%	23%	23%	14%	4%	0%	0%
FMY	FL	FORT MYERS	2%	3%	4%	7%	11%	13%	14%	14%	13%	10%	5%	4%
FNT	MI	FLINT	0%	0%	0%	0%	7%	21%	34%	27%	8%	2%	0%	0%
FSD	SD	SIOUX FALLS	0%	0%	0%	1%	5%	18%	38%	27%	9%	1%	0%	0%
FSM	AR	FORT SMITH	0%	0%	1%	3%	9%	20%	25%	25%	13%	3%	0%	0%
FWA	IN	FORT WAYNE	0%	0%	0%	1%	8%	24%	32%	25%	9%	2%	0%	0%
FYV	AR	FAYETTEVILLE	0%	0%	1%	2%	8%	20%	27%	28%	11%	2%	0%	0%
GCK	KS	GARDEN CITY	0%	0%	0%	1%	7%	22%	30%	27%	11%	2%	0%	0%
GEG	WA	SPOKANE	0%	0%	0%	0%	3%	7%	44%	35%	10%	0%	0%	0%
GFK	ND	GRAND FORKS	0%	0%	0%	0%	4%	18%	42%	28%	8%	1%	0%	0%
GFL	NY	GLENS FALLS	0%	0%	0%	0%	5%	20%	39%	27%	8%	0%	0%	0%
GLD	KS	GOODLAND	0%	0%	0%	0%	5%	20%	35%	29%	9%	1%	0%	0%
GLS	TX	GALVESTON	0%	0%	2%	6%	11%	16%	17%	18%	15%	10%	4%	1%
GNV	FL	GAINESVILLE	1%	1%	2%	5%	11%	17%	19%	19%	15%	8%	2%	1%
GRB	WI	GREEN BAY	0%	0%	0%	0%	5%	21%	38%	26%	7%	1%	0%	0%
GRI	NE	GRAND ISLAND	0%	0%	0%	1%	7%	21%	33%	27%	9%	1%	0%	0%
GRR	MI	GRAND RAPIDS	0%	0%	0%	0%	7%	21%	34%	27%	9%	1%	0%	0%
GSO	NC	GREENSBORO	0%	0%	1%	2%	9%	21%	27%	25%	13%	3%	0%	0%
GSP	SC	GREENVILLE	0%	0%	1%	2%	9%	21%	25%	25%	14%	3%	0%	0%
GTF	MT	GREAT FALLS	0%	0%	0%	0%	1%	6%	48%	35%	9%	0%	0%	0%
GUP	NM	GALLUP	0%	0%	0%	0%	1%	17%	46%	30%	6%	0%	0%	0%
GWO	MS	GREENWOOD	0%	0%	2%	4%	11%	19%	21%	23%	14%	4%	1%	0%
HAT	NC	CAPE HATTERAS	1%	1%	2%	5%	10%	16%	18%	18%	15%	9%	3%	1%
HBR	OK	HOBART	0%	0%	1%	2%	9%	21%	25%	25%	13%	4%	0%	0%
HIB	MN	HIBBING	0%	0%	0%	0%	5%	14%	48%	29%	4%	0%	0%	0%
HKY	NC	HICKORY	0%	0%	0%	2%	9%	22%	26%	26%	13%	2%	0%	0%
HLN	MT	HELENA	0%	0%	0%	0%	2%	9%	49%	33%	7%	0%	0%	0%
HNL	HI	HONOLULU-OAHU	6%	5%	6%	7%	9%	10%	11%	11%	10%	10%	8%	7%
HOM	AK	HOMER	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%
HON	SD	HURON	0%	0%	0%	0%	4%	18%	39%	28%	9%	1%	0%	0%
HSV	AL	HUNTSVILLE	0%	0%	1%	3%	10%	21%	23%	24%	14%	3%	0%	0%
HTL	MI	HOUGHTON LAKE	0%	0%	0%	0%	7%	21%	38%	25%	6%	1%	0%	0%
HTS	WV	HUNTINGTON	0%	0%	1%	2%	8%	21%	28%	27%	12%	2%	0%	0%
HUL	ME	HOULTON	0%	0%	0%	0%	3%	16%	45%	28%	8%	1%	0%	0%
HVR	MT	HAVRE	0%	0%	0%	0%	3%	8%	50%	33%	6%	0%	0%	0%
IAH	TX	HOUSTON	1%	1%	3%	6%	11%	17%	18%	19%	14%	7%	2%	1%
ICT	KS	WICHITA	0%	0%	0%	2%	8%	21%	28%	26%	12%	3%	0%	0%
IDA	ID	IDAHO FALLS	0%	0%	0%	0%	1%	10%	51%	34%	4%	0%	0%	0%
ILG	DE	WILMINGTON	0%	0%	0%	1%	6%	20%	32%	26%	12%	2%	0%	0%
ILM	NC	WILMINGTON	0%	0%	1%	3%	9%	19%	24%	23%	14%	5%	0%	0%
IND	IN	INDIANAPOLIS	0%	0%	1%	1%	8%	21%	28%	27%	12%	2%	0%	0%
INL	MN	INT'L FALLS	0%	0%	0%	0%	5%	16%	45%	27%	6%	1%	0%	0%

Station Location			10-year Average Monthly CDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
INW	AZ	WINSLOW	0%	0%	0%	1%	6%	21%	34%	27%	12%	1%	0%	0%
IPT	PA	WILLIAMSPORT	0%	0%	0%	1%	6%	21%	35%	26%	9%	1%	0%	0%
ISN	ND	WILLISTON	0%	0%	0%	0%	2%	11%	46%	33%	7%	0%	0%	0%
ITO	HI	HILO-HAWAII	6%	6%	7%	7%	9%	9%	10%	11%	10%	10%	8%	7%
JAX	FL	JACKSONVILLE	1%	1%	2%	5%	11%	17%	20%	20%	15%	7%	1%	1%
JKL	KY	JACKSON	0%	0%	1%	4%	9%	20%	25%	26%	12%	3%	0%	0%
JLN	MO	JOPLIN	0%	0%	1%	3%	8%	20%	27%	27%	11%	3%	0%	0%
JNU	AK	JUNEAU	0%	0%	0%	0%	0%	44%	44%	11%	0%	0%	0%	0%
JXN	MI	JACKSON	0%	0%	0%	1%	7%	21%	34%	27%	9%	2%	0%	0%
KTN	AK	KETCHIKAN	0%	0%	0%	0%	0%	15%	54%	31%	0%	0%	0%	0%
LAF	IN	WEST LAFAYETTE	0%	0%	1%	1%	8%	22%	29%	26%	10%	2%	0%	0%
LAN	MI	LANSING	0%	0%	0%	0%	7%	21%	35%	27%	8%	1%	0%	0%
LAS	NV	LAS VEGAS	0%	0%	1%	4%	11%	18%	24%	22%	15%	5%	1%	0%
LAX	CA	LOS ANGELES	1%	1%	1%	3%	5%	8%	20%	22%	20%	13%	5%	0%
LBB	TX	LUBBOCK	0%	0%	1%	3%	11%	23%	24%	24%	12%	3%	0%	0%
LBF	NE	NORTH PLATTE	0%	0%	0%	0%	4%	18%	38%	29%	9%	1%	0%	0%
LCH	LA	LAKE CHARLES	0%	1%	2%	5%	12%	18%	19%	20%	15%	7%	2%	1%
LEB	NH	LEBANON	0%	0%	0%	0%	5%	19%	39%	27%	9%	1%	0%	0%
LEX	KY	LEXINGTON	0%	0%	0%	2%	8%	21%	27%	27%	12%	2%	0%	0%
LFK	TX	LUFKIN	0%	1%	2%	5%	11%	18%	20%	21%	15%	6%	2%	1%
LFT	LA	LAFAYETTE	1%	1%	3%	6%	12%	17%	18%	19%	14%	7%	2%	1%
LGA	NY	NEW YORK	0%	0%	0%	1%	5%	19%	32%	28%	14%	3%	0%	0%
LIH	HI	LIHUE-KAUAI	6%	5%	6%	7%	9%	10%	11%	11%	11%	10%	8%	7%
LIT	AR	LITTLE ROCK	0%	0%	1%	3%	10%	20%	23%	24%	14%	3%	0%	0%
LND	WY	LANDER	0%	0%	0%	0%	1%	14%	46%	33%	6%	0%	0%	0%
LNK	NE	LINCOLN	0%	0%	0%	1%	7%	21%	33%	27%	9%	2%	0%	0%
LOL	NV	LOVELOCK	0%	0%	0%	0%	4%	16%	41%	29%	9%	1%	0%	0%
LRD	TX	LAREDO	1%	2%	5%	9%	12%	15%	15%	16%	12%	8%	3%	1%
LSE	WI	LACROSSE	0%	0%	0%	1%	6%	21%	35%	26%	9%	2%	0%	0%
LWS	ID	LEWISTON	0%	0%	0%	0%	4%	10%	39%	34%	12%	0%	0%	0%
LWT	MT	LEWISTOWN	0%	0%	0%	0%	0%	6%	51%	34%	8%	0%	0%	0%
LYH	VA	LYNCHBURG	0%	0%	0%	2%	7%	21%	30%	28%	11%	2%	0%	0%
MAF	TX	MIDLAND ODESSA	0%	0%	1%	5%	12%	21%	21%	22%	12%	5%	0%	0%
MBS	MI	SAGINAW	0%	0%	0%	0%	7%	22%	34%	26%	8%	2%	0%	0%
MCB	MS	MCCOMB	0%	0%	2%	4%	11%	19%	20%	21%	15%	5%	1%	1%
MCI	MO	KANSAS CITY	0%	0%	1%	2%	8%	21%	29%	27%	10%	2%	0%	0%
MCN	GA	MACON	0%	0%	1%	3%	10%	20%	23%	23%	15%	4%	0%	0%
MCO	FL	ORLANDO	1%	2%	3%	7%	11%	14%	16%	16%	14%	9%	3%	2%
MCW	IA	MASON CITY	0%	0%	0%	0%	6%	22%	36%	26%	8%	2%	0%	0%
MEM	TN	MEMPHIS	0%	0%	1%	3%	11%	20%	22%	24%	14%	4%	0%	0%
MFD	OH	MANSFIELD	0%	0%	0%	1%	8%	21%	31%	27%	9%	2%	0%	0%
MFE	TX	MCALLEN	2%	3%	5%	8%	11%	14%	14%	15%	12%	9%	4%	2%
MFR	OR	MEDFORD	0%	0%	0%	0%	4%	10%	37%	32%	15%	1%	0%	0%
MGM	AL	MONTGOMERY	0%	0%	1%	4%	10%	19%	22%	22%	15%	5%	1%	0%
MGW	WV	MORGANTOWN	0%	0%	0%	2%	8%	19%	29%	27%	11%	2%	0%	0%
MHS	CA	MT SHASTA	0%	0%	0%	0%	4%	11%	45%	30%	9%	0%	0%	0%
MIA	FL	MIAMI	4%	4%	5%	8%	10%	12%	13%	13%	12%	10%	6%	5%
MKE	WI	MILWAUKEE	0%	0%	0%	0%	4%	18%	35%	30%	10%	2%	0%	0%
MKG	MI	MUSKEGON	0%	0%	0%	0%	6%	20%	34%	29%	9%	1%	0%	0%
MKL	TN	JACKSON	0%	0%	1%	3%	10%	20%	24%	25%	13%	3%	0%	0%

Station Location			10-year Average Monthly CDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
MLB	FL	MELBOURNE	2%	2%	3%	6%	11%	14%	15%	16%	14%	10%	4%	3%
MLC	OK	MCALESTER	0%	0%	1%	3%	9%	19%	24%	25%	13%	4%	1%	0%
MLI	IL	MOLINE	0%	0%	0%	1%	8%	22%	31%	26%	10%	2%	0%	0%
MLS	MT	MILES CITY	0%	0%	0%	0%	2%	13%	43%	32%	9%	1%	0%	0%
MLU	LA	MONROE	0%	0%	2%	4%	11%	19%	21%	22%	15%	5%	1%	0%
MOB	AL	MOBILE	0%	0%	2%	4%	11%	18%	20%	21%	15%	6%	1%	1%
MOT	ND	MINOT	0%	0%	0%	0%	2%	14%	43%	32%	8%	0%	0%	0%
MPV	VT	MONTPELIER	0%	0%	0%	0%	4%	20%	41%	27%	8%	0%	0%	0%
MRB	WV	MARTINSBURG	0%	0%	0%	1%	7%	21%	32%	27%	11%	2%	0%	0%
MSL	AL	MUSCLE SHOALS	0%	0%	1%	4%	10%	21%	24%	24%	13%	3%	0%	0%
MSN	WI	MADISON	0%	0%	0%	0%	6%	21%	35%	27%	8%	1%	0%	0%
MSO	MT	MISSOULA	0%	0%	0%	0%	1%	8%	51%	34%	6%	0%	0%	0%
MSP	MN	MINNEAPOLIS	0%	0%	0%	0%	6%	20%	37%	27%	9%	2%	0%	0%
MSS	NY	MASSENA	0%	0%	0%	0%	4%	19%	41%	27%	8%	0%	0%	0%
MSY	LA	NEW ORLEANS	1%	1%	2%	6%	12%	17%	18%	19%	15%	7%	2%	1%
NYL	AZ	YUMA	0%	1%	3%	5%	11%	16%	20%	19%	15%	8%	2%	0%
OFK	NE	NORFOLK	0%	0%	0%	1%	7%	20%	34%	27%	9%	2%	0%	0%
OGG	HI	KAHULUI-MAUI	6%	5%	6%	7%	9%	10%	11%	11%	11%	10%	8%	7%
OKC	OK	OKLAHOMA CITY	0%	0%	1%	3%	9%	20%	25%	25%	13%	3%	0%	0%
OLM	WA	OLYMPIA	0%	0%	0%	0%	2%	8%	44%	39%	7%	0%	0%	0%
OMA	NE	OMAHA	0%	0%	0%	1%	7%	21%	32%	27%	9%	2%	0%	0%
ORD	IL	CHICAGO	0%	0%	0%	1%	6%	20%	33%	28%	10%	2%	0%	0%
ORF	VA	NORFOLK	0%	0%	0%	3%	8%	20%	27%	24%	14%	4%	0%	0%
ORH	MA	WORCESTER	0%	0%	0%	1%	5%	17%	39%	28%	9%	1%	0%	0%
OTM	IA	OTTUMWA	0%	0%	0%	1%	7%	22%	32%	27%	9%	2%	0%	0%
P11	ND	DEVIL'S LAKE	0%	0%	0%	0%	5%	15%	41%	30%	7%	1%	0%	0%
PAH	KY	PADUCAH	0%	0%	1%	2%	9%	22%	26%	26%	12%	2%	0%	0%
PBI	FL	WEST PALM BEAC	3%	3%	4%	7%	10%	12%	13%	14%	12%	10%	6%	5%
PDT	OR	PENDLETON	0%	0%	0%	0%	4%	9%	42%	35%	10%	0%	0%	0%
PDX	OR	PORTLAND	0%	0%	0%	0%	4%	9%	35%	36%	15%	0%	0%	0%
PHL	PA	PHILADELPHIA	0%	0%	0%	1%	6%	20%	31%	26%	13%	2%	0%	0%
PHX	AZ	PHOENIX	0%	0%	2%	6%	11%	17%	20%	19%	15%	8%	2%	0%
PIA	IL	PEORIA	0%	0%	0%	1%	8%	21%	30%	26%	11%	2%	0%	0%
PIH	ID	POCATELLO	0%	0%	0%	0%	1%	11%	49%	34%	5%	0%	0%	0%
PIR	SD	PIERRE	0%	0%	0%	0%	3%	15%	40%	31%	10%	1%	0%	0%
PIT	PA	PITTSBURGH	0%	0%	0%	1%	8%	20%	32%	28%	10%	2%	0%	0%
PKB	WV	PARKERSBURG	0%	0%	0%	2%	10%	20%	28%	26%	11%	2%	0%	0%
PNS	FL	PENSACOLA	0%	0%	2%	4%	11%	18%	20%	20%	15%	7%	1%	1%
PRB	CA	PASO ROBLES	0%	0%	0%	1%	7%	16%	29%	26%	17%	4%	0%	0%
PUB	CO	PUEBLO	0%	0%	0%	0%	4%	22%	35%	29%	9%	1%	0%	0%
PVD	RI	PROVIDENCE	0%	0%	0%	0%	3%	17%	38%	29%	11%	1%	0%	0%
PWM	ME	PORTLAND	0%	0%	0%	0%	2%	15%	43%	30%	9%	0%	0%	0%
RAP	SD	RAPID CITY	0%	0%	0%	0%	2%	13%	42%	32%	9%	1%	0%	0%
RBL	CA	RED BLUFF	0%	0%	0%	2%	8%	18%	28%	24%	16%	3%	0%	0%
RDD	CA	REDDING	0%	0%	0%	2%	8%	18%	29%	25%	16%	3%	0%	0%
RDM	OR	REDMOND	0%	0%	0%	0%	3%	7%	51%	33%	7%	0%	0%	0%
RDU	NC	RALEIGH DURHAM	0%	0%	1%	3%	9%	20%	26%	24%	13%	3%	0%	0%
RFD	IL	ROCKFORD	0%	0%	1%	0%	7%	21%	33%	26%	10%	2%	0%	0%
RIC	VA	RICHMOND	0%	0%	0%	2%	8%	20%	28%	25%	13%	3%	0%	0%
RKS	WY	ROCK SPRINGS	0%	0%	0%	0%	0%	14%	52%	31%	3%	0%	0%	0%

Station Location			10-year Average Monthly CDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
RNO	NV	RENO	0%	0%	0%	0%	4%	16%	39%	29%	12%	0%	0%	0%
ROA	VA	ROANOKE	0%	0%	1%	2%	8%	21%	28%	26%	11%	2%	0%	0%
ROC	NY	ROCHESTER	0%	0%	0%	1%	6%	20%	35%	27%	9%	1%	0%	0%
ROW	NM	ROSWELL	0%	0%	0%	3%	10%	24%	25%	24%	12%	3%	0%	0%
RSL	KS	RUSSELL	0%	0%	0%	1%	7%	22%	31%	26%	10%	2%	0%	0%
RST	MN	ROCHESTER	0%	0%	0%	0%	6%	22%	36%	24%	8%	2%	0%	0%
SAC	CA	SACRAMENTO	0%	0%	0%	2%	8%	18%	28%	24%	18%	4%	0%	0%
SAN	CA	SAN DIEGO	0%	0%	1%	2%	4%	8%	21%	26%	23%	11%	3%	0%
SAT	TX	SAN ANTONIO	0%	1%	3%	6%	11%	17%	18%	20%	14%	7%	2%	0%
SAV	GA	SAVANNAH	0%	0%	1%	4%	11%	18%	21%	21%	15%	6%	1%	0%
SAW	MI	MARQUETTE	0%	0%	0%	0%	5%	19%	42%	27%	7%	1%	0%	0%
SBN	IN	SOUTH BEND	0%	0%	1%	1%	7%	22%	32%	26%	10%	2%	0%	0%
SBY	MD	SALISBURY	0%	0%	0%	2%	7%	19%	32%	25%	12%	3%	0%	0%
SCK	CA	STOCKTON	0%	0%	0%	2%	8%	17%	27%	25%	17%	4%	0%	0%
SDF	KY	LOUISVILLE	0%	0%	1%	3%	9%	21%	25%	26%	13%	3%	0%	0%
SEA	WA	SEATTLE TACOMA	0%	0%	0%	0%	4%	9%	38%	38%	12%	0%	0%	0%
SFO	CA	SAN FRANCISCO	0%	0%	0%	3%	8%	12%	15%	16%	27%	18%	1%	0%
SGF	MO	SPRINGFIELD	0%	0%	1%	2%	8%	21%	28%	28%	11%	2%	0%	0%
SHR	WY	SHERIDAN	0%	0%	0%	0%	1%	10%	47%	35%	7%	0%	0%	0%
SHV	LA	SHREVEPORT	0%	0%	2%	4%	11%	18%	21%	22%	15%	5%	1%	0%
SIT	AK	SITKA	0%	0%	0%	0%	0%	0%	50%	50%	0%	0%	0%	0%
SJT	TX	SAN ANGELO	0%	0%	2%	6%	12%	19%	21%	21%	13%	5%	1%	0%
SLC	UT	SALT LAKE CITY	0%	0%	0%	0%	4%	16%	38%	31%	11%	1%	0%	0%
SLE	OR	SALEM	0%	0%	0%	0%	3%	7%	38%	37%	14%	0%	0%	0%
SLN	KS	SALINA	0%	0%	0%	2%	8%	22%	29%	26%	10%	2%	0%	0%
SNP	AK	ST PAUL ISLAND	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%	8%
SPI	IL	SPRINGFIELD	0%	0%	1%	2%	9%	22%	28%	26%	11%	2%	0%	0%
SPS	TX	WICHITA FALLS	0%	0%	1%	4%	10%	19%	23%	24%	13%	4%	1%	0%
STC	MN	SAINT CLOUD	0%	0%	0%	0%	5%	19%	41%	26%	8%	1%	0%	0%
STL	MO	SAINT LOUIS	0%	0%	1%	2%	9%	21%	27%	26%	11%	3%	0%	0%
SUX	IA	SIOUX CITY	0%	0%	0%	1%	8%	21%	33%	26%	9%	2%	0%	0%
SYR	NY	SYRACUSE	0%	0%	0%	1%	6%	20%	36%	27%	9%	1%	0%	0%
TAD	CO	TRINIDAD	0%	0%	0%	0%	4%	22%	35%	28%	10%	1%	0%	0%
TCL	AL	TUSCALOOSA	0%	0%	1%	4%	11%	20%	22%	23%	14%	4%	0%	0%
TKA	AK	TALKEETNA	0%	0%	0%	0%	0%	39%	51%	10%	0%	0%	0%	0%
TLH	FL	TALLAHASSEE	0%	0%	2%	4%	11%	18%	20%	20%	16%	7%	1%	1%
TOL	OH	TOLEDO	0%	0%	0%	1%	7%	22%	33%	26%	9%	1%	0%	0%
TOP	KS	TOPEKA	0%	0%	1%	2%	8%	21%	29%	27%	10%	2%	0%	0%
TPA	FL	TAMPA	1%	2%	3%	7%	11%	14%	15%	16%	14%	10%	4%	3%
TPH	NV	TONOPAH	0%	0%	0%	0%	3%	18%	39%	29%	11%	1%	0%	0%
TRI	TN	BRISTOL	0%	0%	0%	1%	7%	22%	28%	28%	12%	1%	0%	0%
TUL	OK	TULSA	0%	0%	1%	3%	9%	20%	26%	25%	12%	3%	0%	0%
TUP	MS	TUPELO	0%	0%	1%	3%	10%	20%	23%	24%	14%	4%	0%	0%
TUS	AZ	TUCSON	0%	0%	1%	4%	11%	19%	21%	19%	15%	7%	2%	0%
TVC	MI	TRAVERSE CITY	0%	0%	1%	0%	5%	19%	36%	28%	9%	2%	0%	0%
TXK	AR	TEXARKANA	0%	0%	2%	4%	10%	19%	22%	24%	14%	4%	1%	0%
TYS	TN	KNOXVILLE	0%	0%	1%	2%	9%	21%	25%	26%	13%	2%	0%	0%
UCA	NY	UTICA	0%	0%	0%	2%	11%	21%	28%	24%	12%	3%	0%	0%
UIL	WA	QUILLAYUTE	0%	0%	0%	1%	8%	11%	36%	26%	18%	0%	0%	0%
UIN	IL	QUINCY	0%	0%	0%	2%	8%	21%	29%	27%	10%	2%	0%	0%

Station Location			10-year Average Monthly CDD Data											
Code	State	City	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
VCT	TX	VICTORIA	1%	1%	3%	6%	11%	16%	18%	19%	14%	8%	2%	1%
VRB	FL	VERO BEACH	2%	2%	3%	6%	10%	13%	15%	16%	13%	10%	5%	4%
VTN	NE	VALENTINE	0%	0%	0%	0%	4%	17%	39%	30%	9%	1%	0%	0%
VWS	AK	VALDEZ	0%	0%	0%	0%	11%	25%	46%	18%	0%	0%	0%	0%
WMC	NV	WINNEMUCCA	0%	0%	0%	0%	2%	13%	50%	29%	6%	0%	0%	0%
WRL	WY	WORLAND	0%	0%	0%	0%	2%	15%	46%	30%	6%	1%	0%	0%
YAK	AK	YAKUTAT	0%	0%	0%	0%	0%	0%	100%	0%	0%	0%	0%	0%
YKM	WA	YAKIMA	0%	0%	0%	0%	4%	12%	43%	33%	8%	0%	0%	0%
YNG	OH	YOUNGSTOWN	0%	0%	0%	1%	8%	20%	34%	27%	9%	1%	0%	0%

REFERENCES

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4. American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. *1993 ASHRAE Handbook: Fundamentals*. 1993. ASHRAE: Atlanta, GA.

APPENDIX 7D. REDUCED SET OF RESIDENTIAL BOILER MODELS AND CHARACTERISTICS

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APPENDIX 7D. REDUCED SET OF RESIDENTIAL BOILER MODELS AND CHARACTERISTICS

7D.1 INTRODUCTION

This appendix presents the approach for developing a reduced set of residential boiler models and the resulting residential boiler characteristics.

7D.2 REDUCED SET OF RESIDENTIAL BOILER MODELS DATABASE

7D.2.1 Purpose

The reduced set of residential boiler models was developed to identify actual unique residential boiler models which represent units with different design characteristics. This reduced data set was then expanded by adding information provided in the manufacturers' product literature.

The Air-Conditioning, Heating, and Refrigeration Institute (AHRI) Directory[1] provided the basis for the reduced set of models because it is frequently updated and includes useful data for each model. Not all residential boiler manufacturers are part of AHRI, however, so DOE also looked at other model directories, including the California Energy Commission (CEC),[2] ENERGY STAR®,[3] and Natural Resources Canada (NRCan).[4]

The August 2015 AHRI Directory[1] lists 2203 residential boiler models. The set of residential boiler models was then expanded with data from CEC (765 models) and ENERGY STAR (517 models and groups of models). Many models represent essentially identical units that differ only in brand name. The database of boiler models described here (referred to as the reduced set of residential boiler models or simply the reduced set) represents non-repetitive residential boiler models only. After examining the AHRI Directory database, the Department determined that about 1438 models (762 gas-fired hot water boilers, 95 gas-fired steam boilers, 501 oil-fired hot water boilers, and 80 oil-fired steam boilers) may be considered sufficiently different to be listed as unique models. See the Analysis Inputs spreadsheet ("Models Directory" worksheet) for a complete listing of models used for each residential boiler product class.

Once the reduced set was identified, DOE examined the manufacturer's product literature and added additional data. DOE identified the main residential boiler manufacturers, shown in Table 7D.2.1, and the trade names of their residential boiler lines. Table 7D.2.2 shows the parent companies and number of models by product class in the reduced data set.

Table 7D.2.1 Residential Boiler Manufacturers

Parent Company	Brand Name (Distributor)	AHRI	CEC	ENERGY STAR	NRCan
A.O. Smith Corporation	Lochinvar Corporation	YES	YES	YES	YES
ACV Manufacturing	Triangle Tube	YES	YES	YES	YES

	TRIANGLE TUBE PHASE III INC.	YES	YES	YES	YES
Axeman-Anderson Company	Axeman-Anderson	YES	YES	YES	NO
BDR Thermea	Baxi	NO	YES	YES	YES
	Baxi Spa	NO	YES	YES	YES
Biasi Group	Biasi	NO	NO	YES	YES
	Quincy Hydronic Technology	NO	NO	YES	YES
Bosch Group	Bosch	YES	YES	YES	YES
	Bosch Thermotechnology Corporation	YES	YES	YES	YES
	Buderus	YES	YES	YES	YES
Bradford White Corporation	Bradford White Corporation	YES	YES	YES	NO
	Laars Heating Systems Company	YES	YES	YES	YES
Brant Steel Products Limited	Fleetline	NO	NO	NO	YES
Burnham Holdings	Columbia Heating Products Inc.	YES	NO	NO	NO
	Burnham Commercial	YES	YES	YES	YES
	Crown Boiler Company	YES	YES	YES	YES
	F.W. WEBB	YES	NO	NO	NO
	New Yorker Boiler Company	YES	YES	YES	YES
	PurePro Advantage (F.W. Webb Company)	YES	NO	NO	NO
	U.S. Boiler Company	YES	YES	YES	NO
Camus Hydronics Ltd.	Camus Hydronics	YES	YES	YES	YES
Clean Burn Inc.	Clean Burn	NO	NO	YES	NO
Conematic Heating Systems Inc.	Conematic Heating Systems	NO	NO	YES	YES
De Dietrich Thermique Group	DDR AMERICAS, INC.	YES	YES	YES	YES
	De Dietrich Boilers	YES	YES	YES	YES
Dennison Holdings Ltd.	NY THERMAL INC.	YES	YES	YES	YES
Eco Heating Systems BV	Hamilton Engineering	NO	YES	YES	YES
	Propak (Huron Valley Sales)	NO	YES	NO	YES
ECR International	Argo	NO	NO	NO	NO
	Bryant	YES	NO	YES	NO
	Carrier Corporation	YES	YES	YES	YES
	Dunkirk Boilers	YES	YES	YES	NO
	ECR INTERNATIONAL	YES	YES	YES	YES
	Kenmore (Sears)	YES	YES	YES	NO
	Lennox Industries	YES	YES	YES	YES
	Olsen Division	YES	NO	YES	YES
	Pennco	YES	YES	YES	NO
	SEARS, ROEBUCK AND COMPANY	YES	YES	YES	NO

	Ultimate Engineering	NO	YES	YES	NO
	Utica Boilers	YES	YES	YES	NO
Energy Kinetics	Energy Kinetics	NO	NO	YES	NO
	Energy Kinetics System 2000	NO	NO	YES	NO
E-Z-Rect Manufaturing Ltd.	Allied Engineering Company	NO	NO	YES	YES
Firebird Heating Solutions	Firebird	NO	NO	YES	NO
Glowcore Corp.	Glowcore	NO	YES	NO	NO
Granby Industries	GRANBY FURNACES, INC.	NO	NO	NO	YES
	Kerr**	NO	NO	NO	YES
	Pensotti	YES	NO	YES	YES
	PNA, Inc.	YES	NO	YES	YES
Heat Transfer Products, Inc.	HTP, INC.	YES	YES	YES	YES
	Westinghouse	YES	NO	YES	NO
IBC Technologies, Inc.	IBC Technologies	YES	YES	YES	YES
Intellihot Green Technologies, Inc	Intellihot Green Technologies, Inc	NO	NO	YES	NO
King Heating Products	Eco King	NO	NO	NO	YES
	King Heating Products, Inc.	NO	NO	NO	YES
Kyung Dong Navien Co., Ltd.	Navien	NO	YES	YES	YES
Mestek, Inc.	Advanced Thermal Hydronics	YES	YES	YES	NO
	Embassy Industries	YES	YES	YES	NO
	Hydrotherm	YES	YES	YES	YES
	RBI Water Heater	YES	YES	YES	NO
	Smith Cast Iron Boilers	YES	YES	YES	NO
	Spacepak	YES	YES	YES	NO
Monitor Products, Inc.	Monitor Products	NO	NO	YES	NO
Newmac Manufacturing	Newmac Manufacturing	NO	YES	YES	YES
Noritz Corporation	Noritz America Corporation	NO	YES	NO	NO
Ouellet Group Canada	Dettson	NO	NO	NO	YES
Paloma Industries	Propak (Huron Valley Sales)	NO	YES	NO	YES
	Raypak	YES	YES	YES	YES
PB Heat, LLC.	National HVAC Manufacturing Company, LLC	YES	NO	NO	NO
	P. B. Heat, LLC	YES	YES	YES	YES
	Peerless Boilers	YES	YES	YES	YES
PVI Industries	PVI	NO	YES	NO	NO
Quietside Corporation	Quietside	NO	YES	YES	NO
Rinnai Corporation	Rinnai	YES	YES	YES	YES
Robur Corporation	Servel	NO	YES	NO	NO
Sime	SIME North America (Thermal Hydronic Supply Ltd.)	YES	YES	YES	YES

	Thermal Hydronic Supply Ltd.	YES	YES	YES	YES
Slant/Fin Corporation	Slant/Fin	YES	YES	YES	YES
SPX Corporation	Weil-McLain	YES	YES	YES	YES
	Williamson-Thermoflo	YES	YES	YES	NO
TDC Manufacturing, Inc.	Boyertown Furnace Company	YES	YES	YES	NO
	Columbia Boiler Company of Pottstown	NO	YES	YES	NO
	EFM	NO	NO	YES	NO
	F.W. WEBB COMPANY	YES	YES	YES	NO
	PurePro Trio Boiler (F.W. Webb Company)	YES	YES	YES	NO
	TDC MANUFACTURING, INC.	NO	YES	YES	NO
	Thermo-Dynamics Boiler Company	NO	YES	YES	NO
Thermal Solutions	Thermal Solutions	NO	YES	NO	NO
Toyotomi Co., Ltd.	Toyotomi	NO	NO	YES	NO
Trane And American Standard Heating And Air Conditioning	American Standard	NO	NO	YES	NO
	Trane	NO	NO	YES	NO
United Technologies Corporation	Arcoaire	NO	NO	NO	YES
	Comfortmaker	NO	NO	NO	YES
	Heil	NO	NO	NO	YES
	Keeprite	NO	NO	NO	YES
	Tempstar	NO	NO	NO	YES
Viessmann Group	Viessmann Manufacturing Company	YES	YES	YES	YES
W.R. Benjamin Products Ltd.	Benjamin	NO	NO	NO	YES

Table 7D.2.2 Residential Boiler Model Count in Reduced Set by Product Class

	HWGB	SGB	HWOB	SOB
A.O. Smith	33	0	0	0
ACV Manufacturing	11	0	0	0
BDR Thermea	8	0	0	0
Biasi Group	10	0	7	0
Bosch Group	32	0	7	0
Bradford White Corporation	35	0	0	0
Burnham Holdings	121	18	85	31
Camus Hydronics Ltd.	28	0	0	0
Conematic Heating Systems Inc.	2	0	0	0
De Dietrich Thermique Group	3	0	0	0
Dennison Holdings Ltd.	27	0	17	0

Eco Heating Systems BV	4	0	0	0
ECR International	85	26	75	8
Energy Kinetics, Inc.	15	0	10	0
E-Z-Rect Manufacturing Ltd.	11	0	0	0
Firebird Heating Solutions	0	0	8	0
Granby Industries	12	0	26	0
Heat Transfer Products, Inc.	36	0	0	0
IBC Technologies, Inc.	16	0	0	0
Intellihot Green Technologies, Inc	4	0	0	0
King Heating Products	6	0	0	0
Kyung Dong Navien Co., Ltd.	8	0	0	0
Mestek, Inc.	19	7	6	4
Newmac Manufacturing, Inc.	0	0	2	0
Paloma Group	2	0	0	0
Paloma Industries	18	0	0	0
PB Heat, LLC.	48	14	31	16
Riello Group	1	0	0	0
Rinnai Corporation	10	0	0	0
Sime	5	0	0	0
Slant/Fin Corporation	59	14	77	12
SPX Corporation	62	16	63	9
TDC Manufacturing, Inc.	11	0	81	0
Viessmann Group	20	0	6	0
Total	762	95	501	80

7D.3 REDUCED BOILER MODEL CHARACTERISTICS

Input capacity and distributions by annual fuel utilization efficiency (AFUE) for residential boilers are an essential component in the life-cycle-cost (LCC) analysis. Figure 7D.3.1 to Figure 7D.3.4 show the input capacity distribution for each residential boiler product class. Figure 7D.3.5 to Figure 7D.3.8 show the AFUE distribution for each residential boiler product class.

7D.3.1 Residential Boiler Input Capacity by Product Class

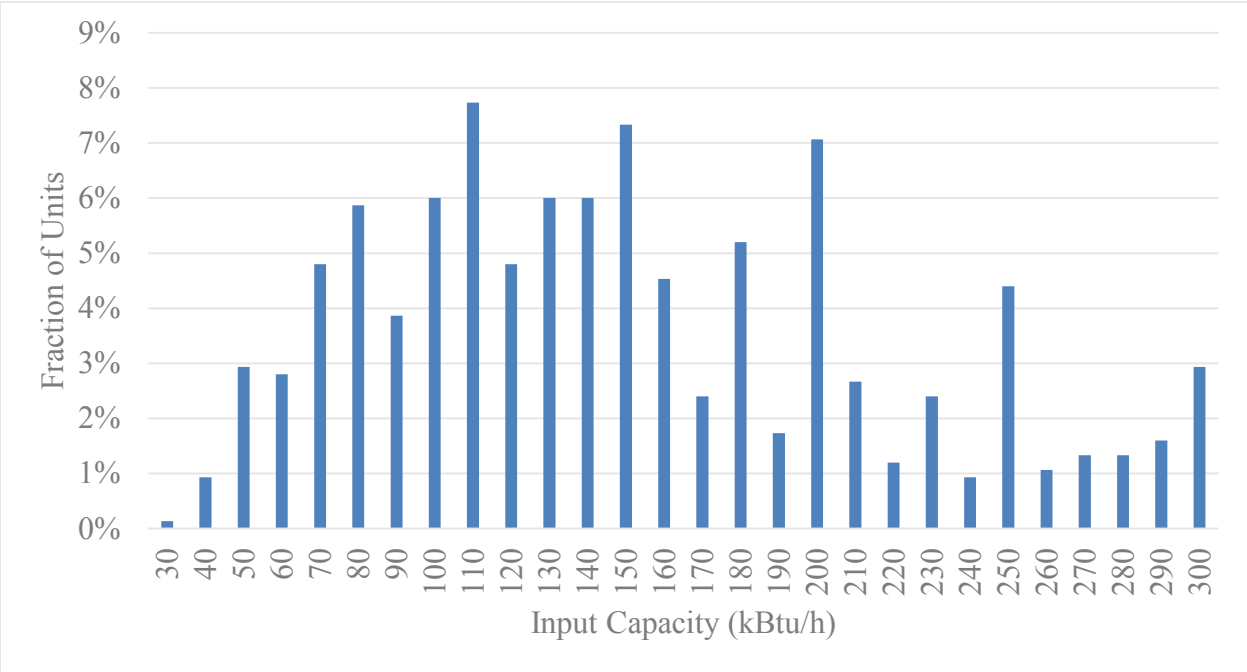

Figure 7D.3.1 Number of Gas-Fired Hot Water Boiler Models by Input Capacity

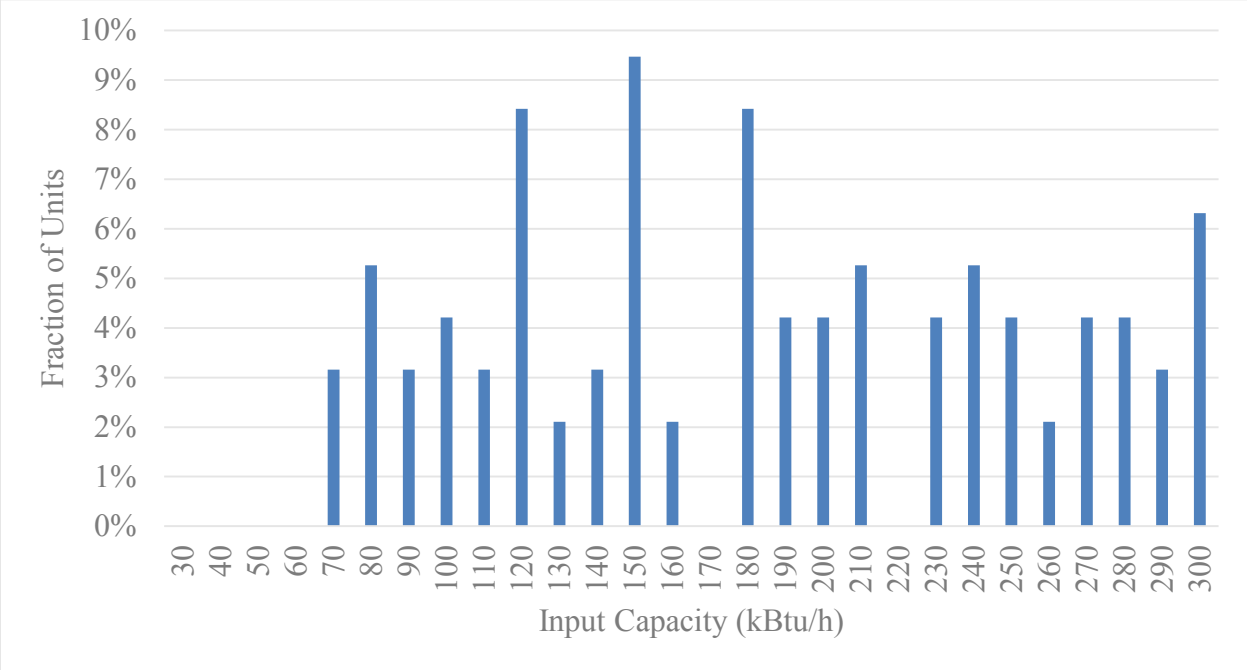

Figure 7D.3.2 Number of Gas-Fired Steam Boiler Models by Input Capacity

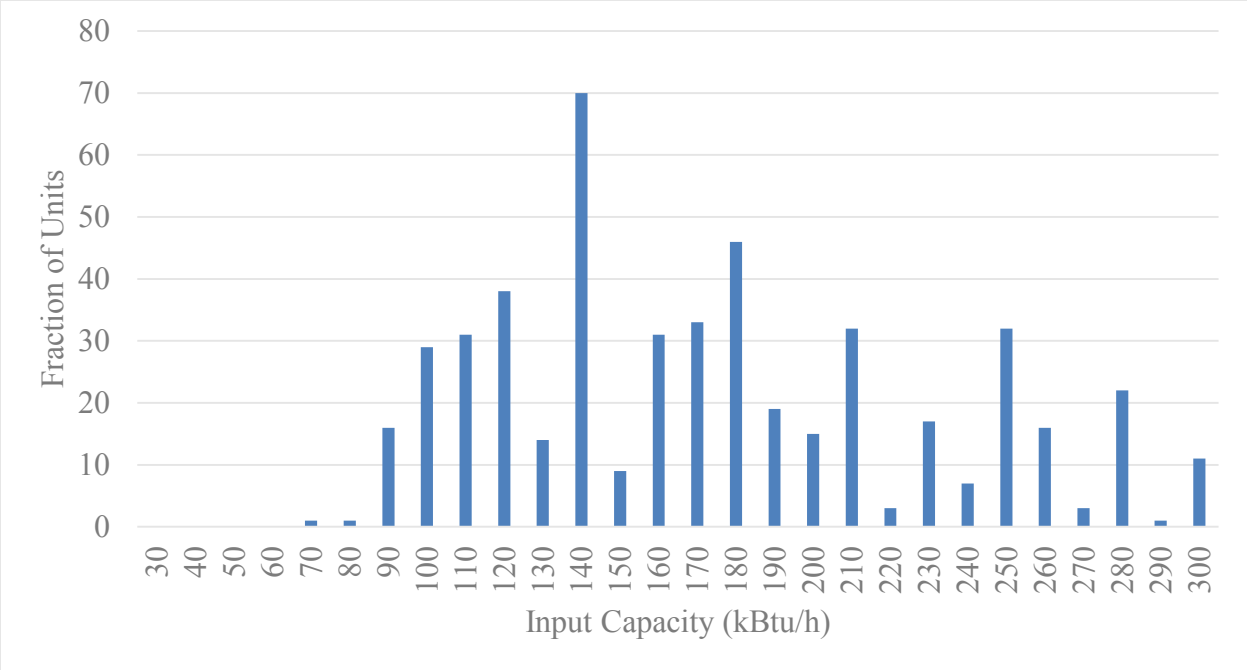

Figure 7D.3.3 Number of Oil-Fired Hot Water Boiler Models by Input Capacity

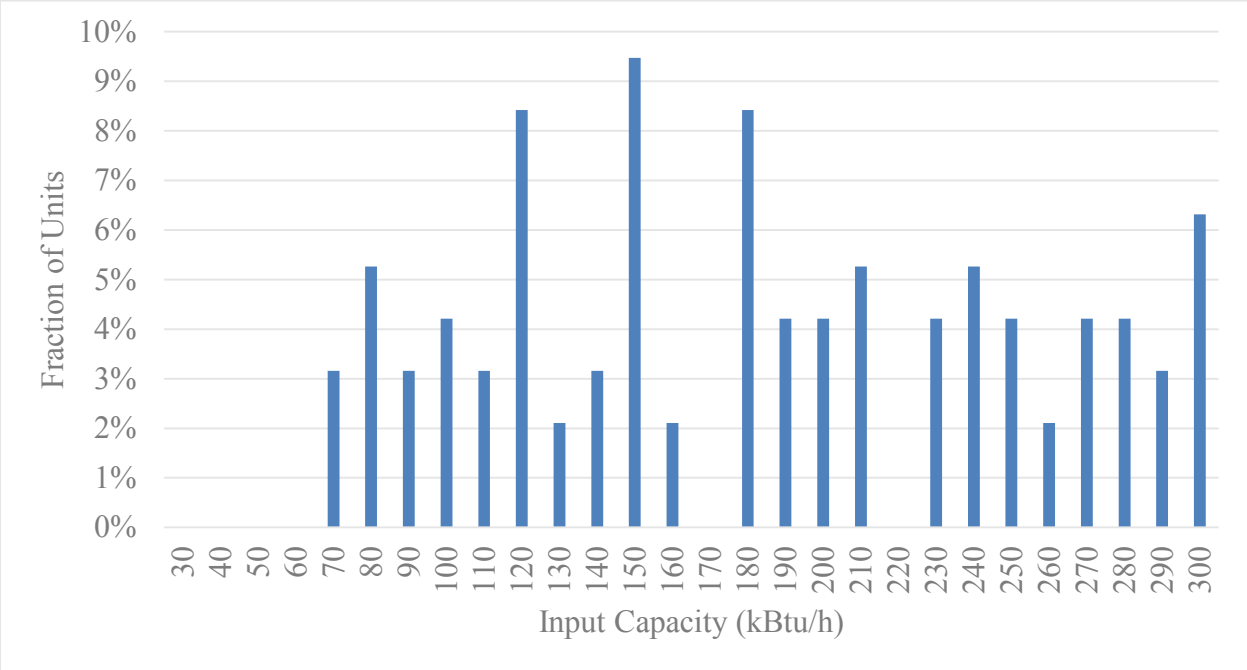

Figure 7D.3.4 Number of Oil-Fired Steam Boiler Models by Input Capacity

7D.3.2 Boiler AFUE by Product Class

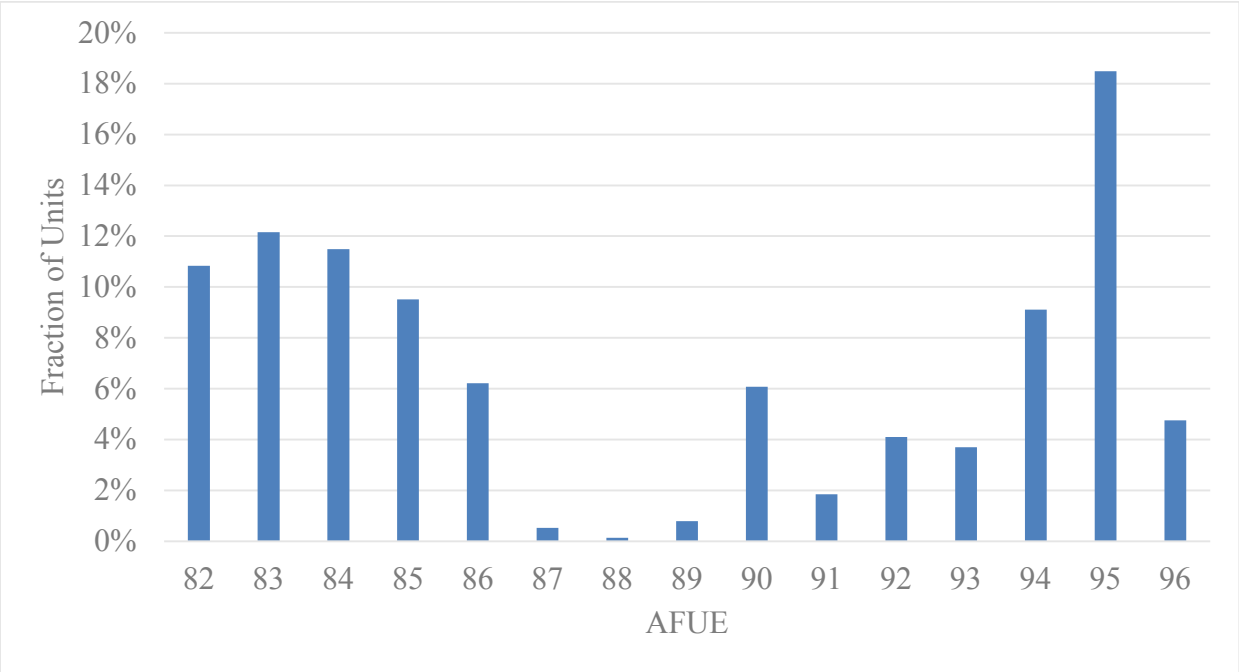

Figure 7D.3.5 Number of Gas-Fired Hot Water Boiler Models by AFUE

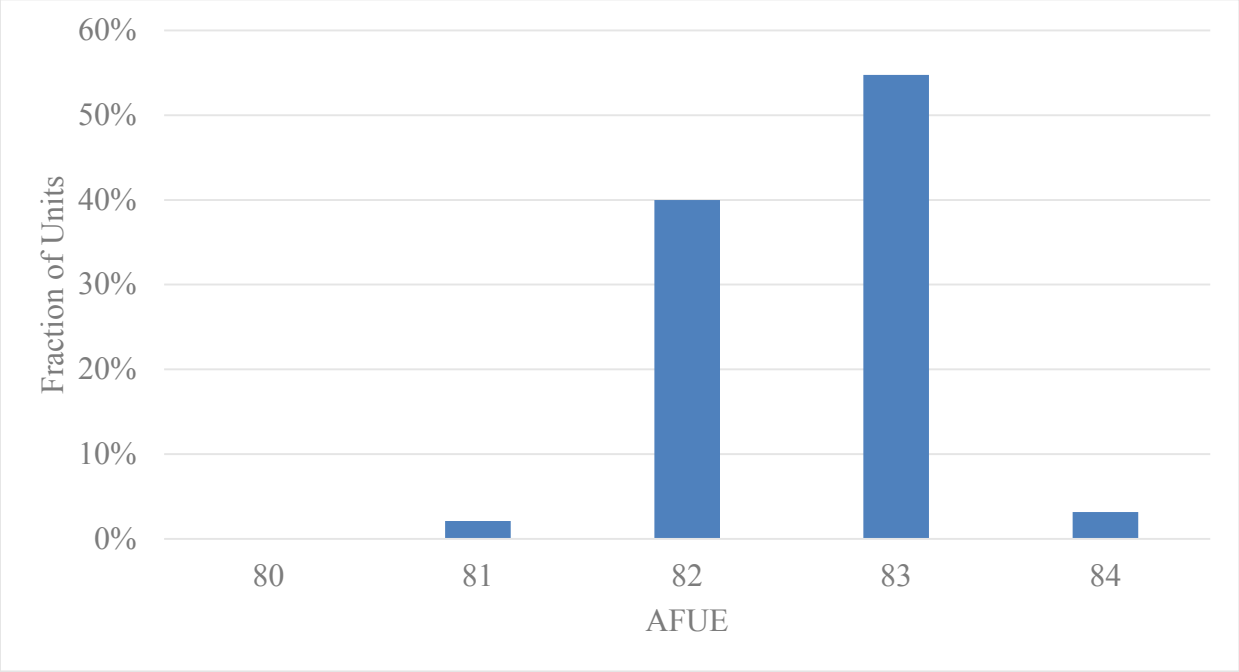

Figure 7D.3.6 Number of Gas-Fired Steam Boiler Models by AFUE

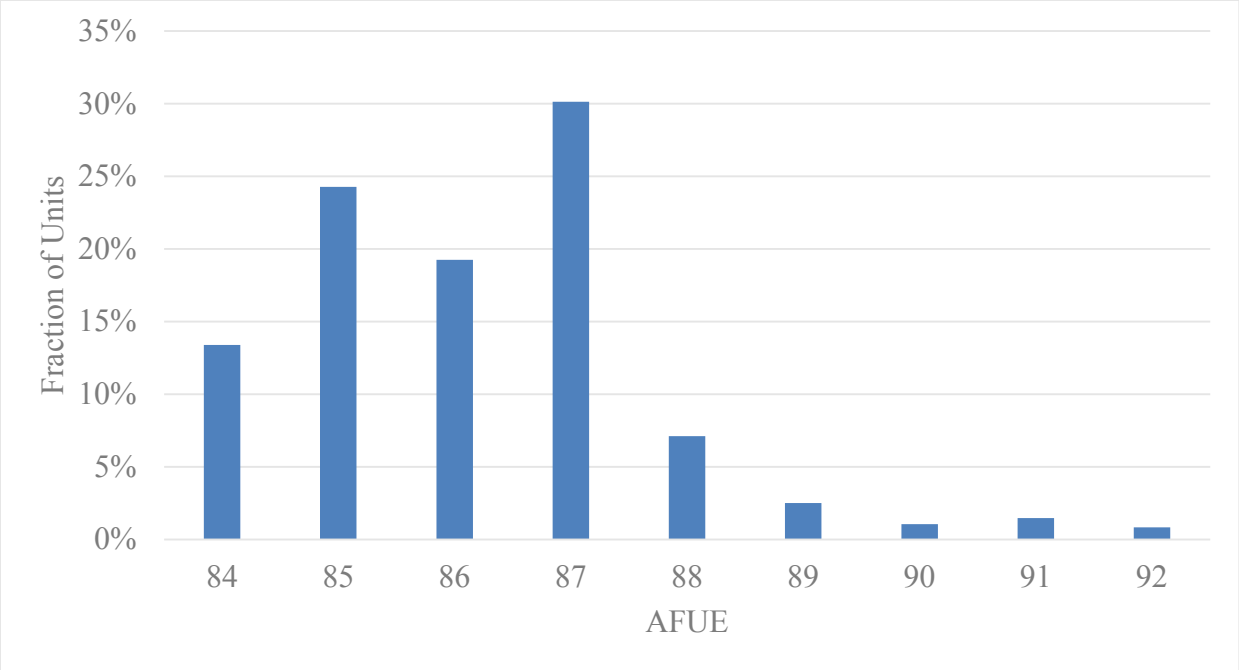

Figure 7D.3.7 Number of Oil-Fired Hot Water Boiler Models by AFUE

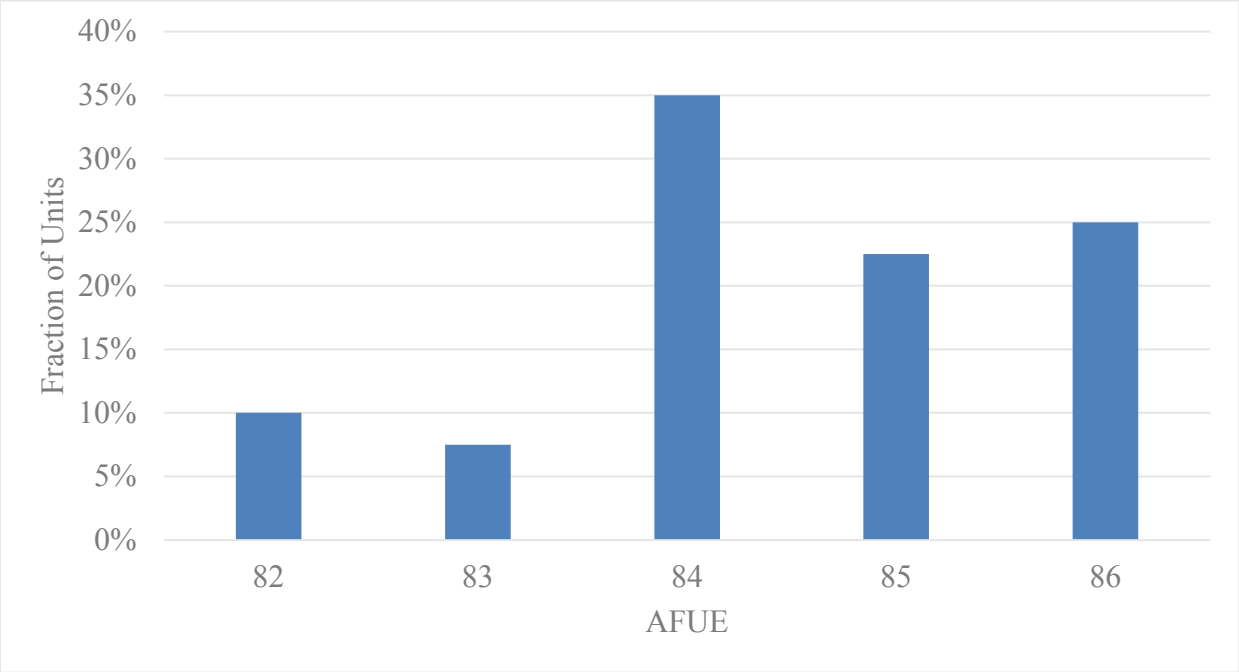

Figure 7D.3.8 Number of Oil-Fired Steam Boiler Models by AFUE

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CHAPTER 8. LIFE-CYCLE COST AND PAYBACK PERIOD ANALYSIS

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CHAPTER 8. LIFE-CYCLE COST AND PAYPACK PERIOD ANALYSIS

8.1 INTRODUCTION

The effect of amended standards on individual customers usually includes a reduction in operating cost and an increase in purchase cost. This chapter describes two metrics used in the analysis to determine the economic impact of standards on individual residential consumers.

- LCC (life-cycle cost) is the total consumer cost of an appliance or product, generally over the life of the appliance or product. The LCC calculation includes total installed cost (manufacturer selling price, distribution chain markups, sales tax, and installation costs), operating costs (energy, repair, and maintenance costs), product lifetime, and discount rate. Future operating costs are discounted to the time of purchase and summed over the lifetime of the appliance or product.
- PBP (payback period) measures the amount of time it takes consumers to recover the assumed higher purchase price of a more energy-efficient product through reduced operating costs. Inputs to the payback period calculation include the installed cost to the consumer and first-year operating costs.

The U.S. Department of Energy (DOE) conducted the LCC and PBP analysis using a spreadsheet model developed in Microsoft Excel. When combined with Crystal Ball (a commercially available software program), the LCC and PBP model generates a Monte Carlo simulation to perform the analysis by incorporating uncertainty and variability considerations in certain key parameters discussed further in section 8.1.1.

Inputs to the LCC and PBP analysis of residential boiler products are discussed in sections 8.2 and 8.3, respectively. Results for each metric are presented in section 8.4. Key variables and calculations are presented for each metric. The calculations discussed here were performed with a series of Microsoft Excel spreadsheets that are accessible over the Internet (www1.eere.energy.gov/buildings/appliance_standards/rulemaking.aspx?ruleid=112).

Details of the spreadsheets and instructions for using them are discussed in appendix 8A.

8.1.1 General Approach for Life-Cycle Cost and Payback Period Analysis

In recognition of the fact that each residential or commercial building using a residential boiler(s) is unique, variability and uncertainty are analyzed by performing the LCC and PBP calculations detailed here for a representative sample of individual households and commercial buildings. The results are expressed as the number of buildings experiencing economic impacts of different magnitudes. The LCC and PBP model was developed using Microsoft Excel spreadsheets combined with Crystal Ball. The LCC and PBP analysis explicitly model both the uncertainty and the variability in the model's inputs using Monte Carlo simulation and probability distributions (see appendix 8B).

The LCC analysis used the estimated energy use for each residential boiler unit as described in the energy use analysis in chapter 7. Energy use of residential boilers is sensitive to climate and therefore varies by location within the United States. Aside from energy use, other important factors influencing the LCC and PBP analysis include energy prices, installation costs, product distribution markups, and sales taxes.

A certain fraction of residential boilers is used in commercial applications. This fraction determines the frequency at which the model's sampling process will select a boiler from the commercial building sample.

As mentioned previously, DOE generated LCC and PBP results as probability distributions using a simulation based on Monte Carlo analysis methods, in which certain key inputs to the analysis consist of probability distributions rather than single-point values. Therefore, the outcomes of the Monte Carlo analysis can also be expressed as probability distributions. As a result, the Monte Carlo analysis produces a range of LCC and PBP results. A distinct advantage of this type of approach is that DOE can identify the percentage of customers achieving LCC savings or attaining certain PBP values due to an increased efficiency level, in addition to the average LCC savings or average PBP for that efficiency level.

The LCC and PBP results are displayed as distributions of impacts compared to the no-new-standards case (*i.e.*, without new or amended standards). The no-new-standards case efficiency is for 2021 and reflects the expected distribution of efficiency levels by product class.

8.1.2 Overview of Life-Cycle Cost and Payback Period Analysis Inputs

The LCC is the total customer cost over the life of the product, including purchase price (including retail markups, sales taxes, and installation costs) and operating cost (including repair costs, maintenance costs, and energy cost). Future operating costs are discounted to the time of purchase and summed over the lifetime of the product. The PBP is the increase in purchase cost of a higher efficiency product divided by the change in annual operating cost of the product. It represents the number of years that it will take the customer to recover the increased purchase cost through decreased operating costs. In the PBP calculation, future costs are not discounted.

Inputs to the LCC and PBP analysis are categorized as: (1) inputs for establishing the purchase cost, otherwise known as the total installed cost; and (2) inputs for calculating the operating cost (*i.e.*, energy, maintenance, and repair costs).

The primary inputs for establishing the total installed cost are:

- *Baseline manufacturer selling price*: The baseline manufacturer selling price (MSP) is the price charged by the manufacturer to a wholesaler for product meeting existing minimum efficiency (or baseline) standards. The MSP includes a markup that converts the cost of production (*i.e.*, the manufacturer cost) to a MSP.

- *Standard-level manufacturer selling price increase*: The standard-level MSP increase is the incremental change in MSP associated with producing product at each of the higher efficiency levels.
- *Markups and sales tax*: Markups and sales tax are the wholesaler and contractor margins and state and local retail sales taxes associated with converting the MSP to a customer price.
- *Installation cost*: Installation cost is the cost to the customer of installing the product. The installation cost represents all costs required to install the product but does not include the marked-up customer product price. The installation cost includes labor, overhead, and any miscellaneous materials and parts.

The primary inputs for calculating the operating cost are:

- *Product energy consumption*: The product energy consumption is the site energy use associated with the use of the boiler to provide space and water heating to the building.
- *Energy Prices*: Electricity, natural gas, liquid petroleum gas (LPG), and fuel oil prices are determined using average monthly energy prices.
- *Electricity, natural gas, and fuel oil price trends*: The Energy Information Administration's (EIA's) *Annual Energy Outlook 2015* (*AEO 2015*)[1] is used to forecast energy prices into the future. For the results presented in this chapter, DOE used the *AEO 2015* Reference case to forecast future energy prices.
- *Maintenance costs*: The labor and material costs associated with maintaining the operation of the equipment.
- *Repair costs*: The labor and material costs associated with repairing or replacing components that have failed.
- *Lifetime*: The age at which the boiler is retired from service.
- *Discount rate*: The rate at which future costs and savings are discounted to establish their present value.

Figure 8.1.1 graphically depicts the relationships between the installed cost and operating cost inputs for the calculation of the LCC and PBP.

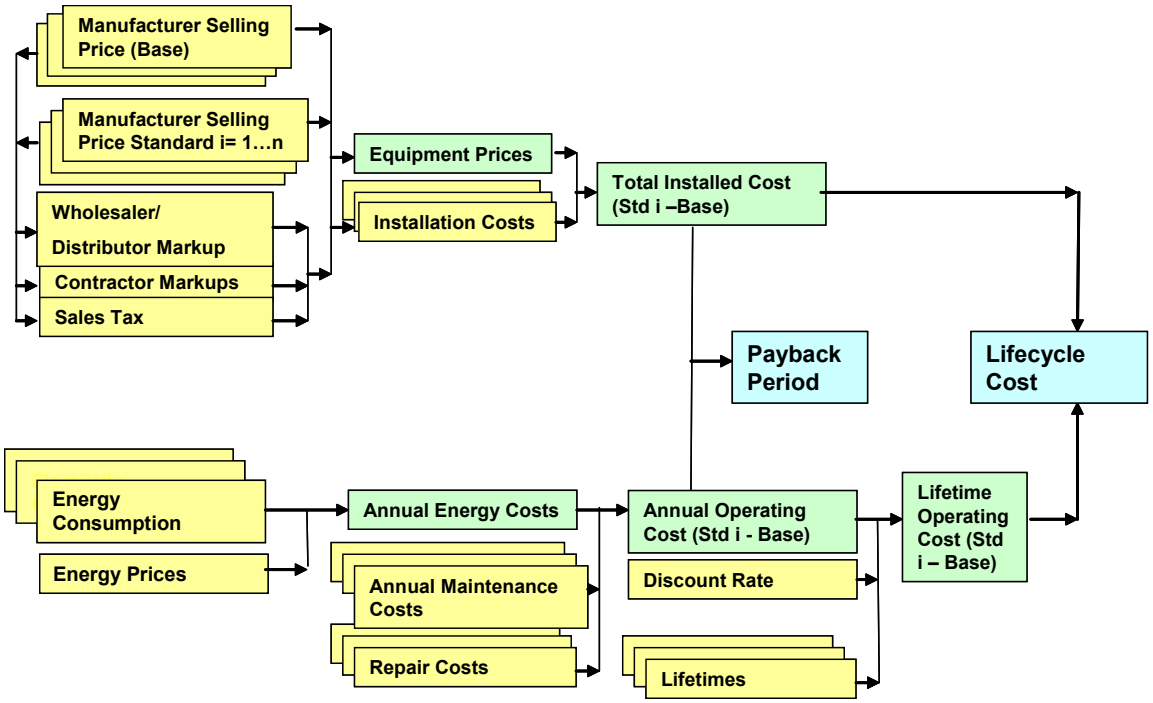

Figure 8.1.1 Flow Diagram of Inputs for the Determination of LCC and PBP

Table 8.1.1 provides descriptions of the various inputs to the calculation of the LCC and PBP. As noted earlier, most of the inputs are characterized by probability distributions that capture variability in the input variables.

Table 8.1.1 Summary of Inputs and Key Assumptions Used in the LCC and PBP Analysis

Inputs	Description
Affecting Installed Costs	
Product Price	Derived MSP for boilers at different heating input capacities (from the engineering analysis) and multiplied by wholesaler markups and contractor markups plus sales tax (from markups analysis). Used the probability distribution for the different markups to describe their variability.
Installation Cost	Includes installation labor derived from *RS Means Residential Cost Data 2015*. Overhead and materials costs and profits are assumed to be included in the contractor's markup. Thus, the total installed cost equals the consumer product price (manufacturer cost multiplied by the various markups plus sales tax) plus the installation cost.
Affecting Operating Costs	
Annual Energy Use	See chapter 7.
Energy Efficiency	The Annual Fuel Utilization Efficiency (AFUE) is the efficiency descriptor for residential boilers. Residential boiler test procedure calculation methodologies are used to determine the annual energy consumption associated with the considered efficiency levels.
Energy Prices	Costs were calculated for RECS 2009 households from monthly marginal average electricity and natural gas, LPG, or fuel oil prices in each of 30 states and groups of states in RECS 2009.[a] Residential prices were escalated by the *AEO 2015* forecasts to estimate future electricity prices. Escalation was performed at the census division level and aggregated to the regions used in the study. Costs were calculated for CBECS 2003 buildings from monthly marginal average electricity and natural gas, LPG, or fuel oil prices in each of 9 divisions in CBECS 2003. Commercial prices were escalated by the *AEO 2015* forecasts to estimate future electricity prices. Escalation was performed at the census division level.
Maintenance Cost	The cost associated with maintaining the operation of the product (*e.g.*, checking blower). It was assumed that condensing products would have higher maintenance costs.
Repair Cost	The annualized repair cost for baseline efficiency boiler product was estimated based on costs of major repair (such as motor replacement) from a variety of published sources. It was assumed that higher-efficiency products would have higher repair costs.
Affecting Present Value of Annual Operating Cost Savings	
Product Lifetime	Used the probability distribution of lifetimes developed for boilers.
Discount Rate	For residential customers based on Federal Reserve Board's *Survey of Consumer Finances*. Probability distributions are used for the discount rates. For commercial customers based on Federal Reserve Board's *Federal Reserve Statistical Releases – Selected Interest Rates*.[b] Probability distributions are used for the discount rates.
Date Standard Becomes Effective	2021 (5 years after expected publication of the final rule)

All of the inputs depicted in Figure 8.1.1 and summarized in Table 8.1.1 are discussed in section 8.2.

8.1.3 Use of Residential Energy Consumption Survey and Commercial Building Energy Consumption Survey in Life-Cycle Cost and Payback Period Analysis

The LCC and PBP calculations detailed here are for a representative sample of individual boiler users. The residential boilers are assumed to be installed both in residential and commercial buildings.

As explained in chapter 7, the Energy Information Administration (EIA)'s 2009 Residential Energy Consumption Survey (RECS 2009)[2] serves as the basis for determining the representative residential sample, while EIA's 2003 Commercial Building Energy Consumption Survey (CBECS 2003) serves as the basis for determining the representative commercial sample.[3] RECS collects energy-related data for occupied primary housing units in the United States. RECS 2009 included data from 12,083 housing units that represent almost 113.6 million households. CBECS collects energy-related data for commercial buildings in the United States. CBECS 2003 included data from 5,215 buildings representing 4.9 million buildings.

Appendix 7A presents the variables used and their definitions, as well as further information about the derivation of the household and building samples.

8.2 LIFE-CYCLE COST ANALYSIS INPUTS

Life-cycle cost is the total customer cost over the life of a product, including purchase cost and operating costs. Future operating costs are discounted to the time of purchase and summed over the lifetime of the product. Life-cycle cost is defined by the following equation:

$$LCC = IC + \sum_{t=1}^{N} OC_t / (1+r)^t$$

Eq. 8.1

Where:

LCC = life-cycle cost ($),
IC = total installed cost ($),
∑ = sum over the lifetime, from year 1 to year N,
where N = lifetime of product (years),
OC = operating cost ($),

---

[a] RECS 2009 provides 27 regions (also called reportable domains). The 27th region originally includes Oregon, Washington, Alaska, and Hawaii. Alaska and Hawaii are subdivided into separate regions (28 and 29, respectively), based on cooling and heating degree days. In addition, region 14 originally included West Virginia, which has been disaggregated into region 30 based on cooling and heating degree days.
[b] The *Federal Reserve Statistical Release* reference includes historical data sets for state and local bonds, CDs, and corporate bonds.

r = discount rate, and
t = year for which operating cost is being determined.

DOE expresses all the costs in 2014$. Total installed cost, operating cost, lifetime, and discount rate are discussed in the following sections. In the LCC analysis, the year of product purchase is assumed to be 2021, the assumed effective date of energy conservation standards for residential boilers.

8.2.1 Total Installed Cost Inputs

The total installed cost to the consumer is defined by the following equation:

$$IC = EQP + INST$$

Eq. 8.2

Where:

EQP = product price ($) (*i.e.*, customer price for the product only), and
$INST$ = installation cost ($) (*i.e.*, the cost for labor and materials).

The product price is based on the distribution channel through which the customer purchases the product. As discussed in chapter 6, DOE defined one major distribution channel for new units to describe how the product passes from the manufacturer to the customer: the manufacturer sells the product to a wholesaler or distributor, who sells to a mechanical contractor hired by a general contractor. In the new construction market, the general contractor is hired by the consumer, but it is the mechanical contractor who typically purchases and installs the product and charges the entire job cost with markup to general contractor. Replacement products follow the same distribution channel, except that there is no general contractor. Instead, the mechanical contractor takes on the general contractor's function.

The remainder of this section provides information about the variables DOE used to calculate the total installed cost for residential boiler products.

8.2.1.1 Manufacturer Costs

DOE developed the manufacturer costs for boilers as described in chapter 5, Engineering Analysis. The manufacturer costs at each efficiency level are shown in Table 8.2.1 for AFUE standards. DOE included the cost of the inducer fan in the manufacturer product cost for all condensing gas-fired boilers and all oil-fired residential boilers. For non-condensing gas-fired boilers, DOE applies the inducer fan cost as an adder to a fraction of boiler installations based on shipments data provided by Burnham, Air-Conditioning, Heating, and Refrigeration Institute (AHRI) contractor survey data, and reduced model dataset (see appendix 7d) primarily based on AHRI's certification directory as indicated in Table 8.2.2.[4–6] DOE determined that the cost of the inducer fan is $96.97. The inducer fan adder does not apply to the product classes and efficiency level that are not present in Table 8.2.2. The manufacturer costs at each efficiency level for standby mode and off mode standards are shown in Table 8.2.3.

Table 8.2.1 Manufacturer Production Cost for Residential Boilers by Efficiency Level (AFUE Standard)

Product Class	Efficiency Level	Manufacturer Production Cost 2014$	Incremental Cost 2014$
Gas-Fired Hot Water Boiler	82% AFUE - Baseline	$632	-
	83% AFUE - Increased HX Area	$639	$8
	84% AFUE - Increased HX Area	$647	$15
	85% AFUE - Increased HX Area	$723	$91
	90% AFUE - Condensing Baseline	$1,010	$378
	92% AFUE - Increased HX Area	$1,180	$548
	96% AFUE - Max Tech	$1,516	$884
Gas-Fired Steam Boiler	80% AFUE - Baseline	$778	-
	82% AFUE - Increased HX Area	$797	$19
	83% AFUE - Max Tech	$934	$156
Oil-Fired Hot Water Boiler	84% AFUE - Baseline	$1,228	-
	85% AFUE - Increased HX Area	$1,302	$75
	86% AFUE - Increased HX Area	$1,377	$149
	91% AFUE - Condensing (Max Tech)	$2,314	$1,087
Oil-Fired Steam Boiler	82% AFUE - Baseline	$1,252	-
	84% AFUE - Increased HX Area	$1,401	$149
	85% AFUE - Increased HX Area	$1,475	$224
	86% AFUE - Max Tech	$1,625	$373

Table 8.2.2 Inducer Cost Adder in Applicable Product Classes and Efficiency Levels

Product Class	Efficiency Level	Inducer Fraction %
Gas-Fired Hot Water Boiler	82% AFUE - Baseline	4.73%
	83% AFUE - Increased HX Area	4.73%
	84% AFUE - Increased HX Area	4.73%
	85% AFUE - Increased HX Area	47.42%
Gas-Fired Steam Boiler	80% AFUE - Baseline	0.00%
	82% AFUE - Increased HX Area	3.95%
	83% AFUE - Max Tech	9.09%

Table 8.2.3 Manufacturer Production Cost for Residential Boilers by Efficiency Level (Standby Mode and Off Mode)

Product Class	Efficiency Level	Manufacturer Production Cost 2014$	Incremental Cost 2014$
Gas-fired Hot Water Boiler	Baseline	$8.6	-
	1	$10.4	$1.9
	2	$18.5	$10.0
	3	$19.0	$10.5
Gas-fired Steam Boiler	Baseline	$8.6	-
	1	$10.4	$1.9
	2	$18.5	$10.0
	3	$19.0	$10.5
Oil-fired Hot Water Boiler	Baseline	$8.6	-
	1	$10.4	$1.9
	2	$18.5	$10.0
	3	$19.0	$10.5
Oil-fired Steam Boiler	Baseline	$8.6	-
	1	$10.4	$1.9
	2	$18.5	$10.0
	3	$19.0	$10.5
Electric Hot Water Boiler	Baseline	$8.6	-
	1	$10.4	$1.9
	2	$18.5	$10.0
	3	$19.0	$10.5
Electric Steam Boiler	Baseline	$8.6	-
	1	$10.4	$1.9
	2	$18.5	$10.0
	3	$19.0	$10.5

8.2.1.2 Markups

For a given distribution channel, the overall markup is the value determined by multiplying all the associated markups and the applicable sales tax together to arrive at a single overall distribution chain markup value. The overall markup is multiplied times the baseline or standard-compliant manufacturer cost to arrive at the price paid by the customer. Because there are baseline and incremental markups associated with the wholesaler and mechanical contractor, the overall markup is also divided into a baseline markup (*i.e.*, a markup used to convert the baseline manufacturer price into a customer price) and an incremental markup (*i.e.*, a markup used to convert a standard-compliant manufacturer cost increase due to an efficiency increase

into an incremental customer price). Markups can differ depending on whether the product is being purchased for a new construction installation or is being purchased to replace an existing product. DOE developed the overall baseline markups and incremental markups for both new construction and replacement applications as a part of the markups analysis (chapter 6).

Because the relative importance of new construction and replacements in total shipments varies among the product classes, the total markup varies as well (Table 8.2.4).

Table 8.2.4 Overall Markup for Residential Boilers by Product Class

Product Class	Baseline Markup	Incremental Markup
Gas-Fired Hot Water Boiler	3.30	2.05
Gas-Fired Steam Boiler	3.24	2.05
Oil-Fired Hot Water Boiler	3.24	2.03
Oil-Fired Steam Boiler	3.23	2.03
Electric Hot Water Boiler	3.19	2.01
Electric Steam Boiler	3.14	2.03

8.2.1.3 Total Consumer Price

DOE derived the consumer product price for the baseline product by taking the product of the baseline manufacturer cost and the baseline overall markup (including the sales tax). For each efficiency level above the baseline, DOE derived the consumer product price by taking the baseline product consumer price and adding to it the product of the incremental manufacturer cost and the incremental overall markup (including the sales tax). Markups and sales tax all can take on a variety of values, depending on location, so the resulting total installed cost for a particular efficiency level is represented by a distribution of values.

Table 8.2.5 and Table 8.2.6 present the average consumer product price for each residential boiler product class and efficiency level for AFUE standards and standby mode and off mode standards, respectively.

Table 8.2.5 Average Consumer Price for Residential Boilers for AFUE Standards

Product Class	Efficiency Level	Average Consumer Price 2014$	Incremental Cost 2014$
Gas-Fired Hot Water Boiler	82% AFUE - Baseline	$2,083	-
	83% AFUE - Increased HX Area	$2,099	$16
	84% AFUE - Increased HX Area	$2,114	$31
	85% AFUE - Increased HX Area	$2,270	$187
	90% AFUE - Condensing Baseline	$2,859	$776
	92% AFUE - Increased HX Area	$3,209	$1,126
	96% AFUE - Max Tech	$3,899	$1,815
Gas-Fired Steam Boiler	80% AFUE - Baseline	$2,518	-
	82% AFUE - Increased HX Area	$2,558	$40
	83% AFUE - Max Tech	$2,837	$319
Oil-Fired Hot Water Boiler	84% AFUE - Baseline	$3,981	-
	85% AFUE - Increased HX Area	$4,132	$151
	86% AFUE - Increased HX Area	$4,283	$302
	91% AFUE - Condensing (Max Tech)	$6,181	$2,201
Oil-Fired Steam Boiler	82% AFUE - Baseline	$4,043	-
	84% AFUE - Increased HX Area	$4,346	$304
	85% AFUE - Increased HX Area	$4,498	$455
	86% AFUE - Max Tech	$4,801	$759

Table 8.2.6 Average Consumer Price for Residential Boilers for Standby Mode and Off Mode

Product Class	Efficiency Level	Average Consumer Price 2014$	Incremental Cost 2014$
Gas-fired Hot Water Boiler	Baseline	$28	-
	1	$32	$4
	2	$49	$20
	3	$50	$21
Gas-fired Steam Boiler	Baseline	$28	-
	1	$31	$4
	2	$48	$20
	3	$49	$21
Oil-fired Hot Water Boiler	Baseline	$28	-
	1	$31	$4
	2	$48	$20
	3	$49	$21
Oil-fired Steam Boiler	Baseline	$28	-
	1	$31	$4
	2	$48	$20
	3	$49	$21
Electric Hot Water Boiler	Baseline	$27	-
	1	$31	$4
	2	$47	$20
	3	$48	$21
Electric Steam Boiler	Baseline	$27	-
	1	$31	$4
	2	$47	$20
	3	$48	$21

8.2.1.4 Future Product Prices

DOE examined historical producer price index PPI data for cast iron heating boilers from 1987-2013 and steel heating boilers from 1980 to 2013 (discontinued between 1987 and 1993) from the Bureau of Labor Statistics (BLS).[c] The PPI data reflect nominal prices, adjusted for product quality changes. The inflation-adjusted (deflated) price indexes for cast iron heating boilers and steel heating boilers were calculated by dividing the PPI series by the Gross Domestic Product Chained Price Index (see Figure 8.2.1).

[c] Cast iron heating boiler PPI series ID: PCU 3334143334141; Steel heating boiler PPI series ID: PCU 3334143334145; www.bls.gov/ppi/

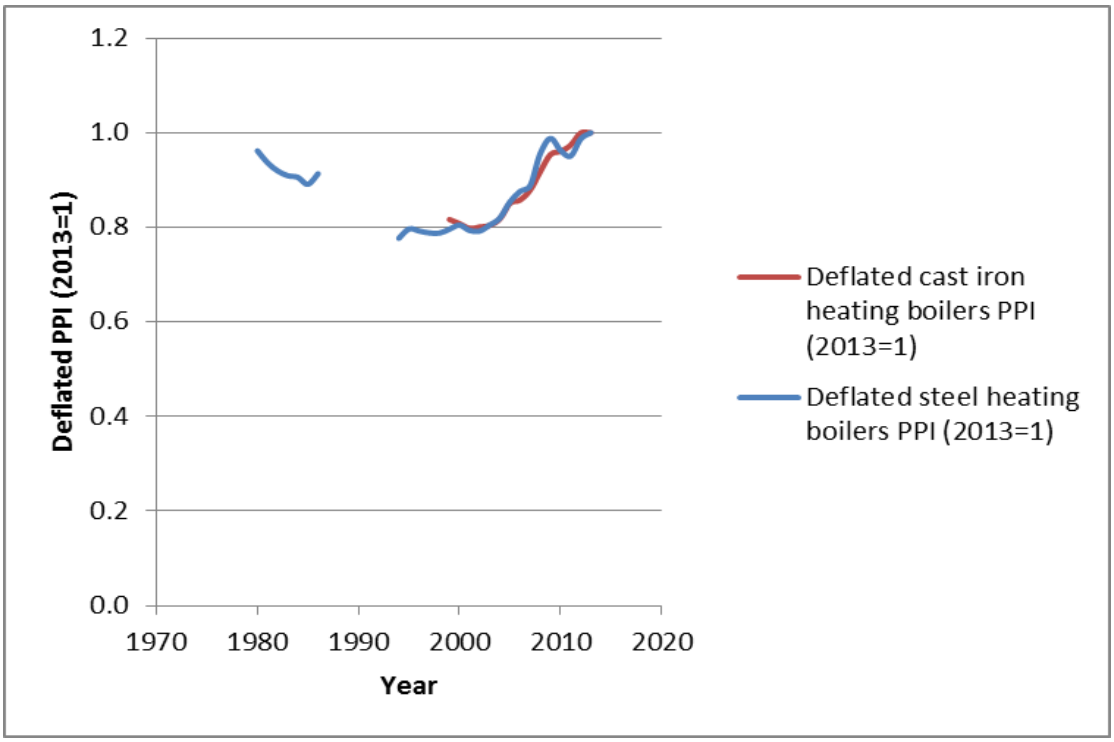

Figure 8.2.1 Historical Deflated Producer Price Indexes for Cast Iron Heating Boilers and Steel Heating Boilers

In Figure 8.2.1, both the cast iron heating boiler PPI and steel heating boiler PPI show strongly rising trend starting from early 2000s, which was found to have strong correlation with the historical price index for iron and steel mills (see Figure 8.2.2).[d] This rise in iron and steel PPI between 2003 and 2008 is primarily a result of large demand of such commodities from rapid industrialization in China, India and other emerging economies. Prior to 2003, the inflation-adjusted PPI for iron and steel mills was in a long downtrend that began in the early 1980s. The limited historical PPI for steel heating boilers also showed that the steel heating boilers likely had a downward price trend during the same period of time. The recent trend in iron and steel PPI could be a start of a return to a declining trend, but there is not enough data to draw a definitive conclusion.

Given the pattern in iron and steel prices, DOE is not confident that extrapolating the trend in the PPI for cast iron heating boilers or steel heating boilers would provide a sound projection. Nor is DOE confident that the recent downward trend in iron and steel prices will continue in the future. Given the uncertainty, DOE chose to apply a constant price trend to the manufacturer selling price (in real dollars) of residential boilers.

[d] Iron and steel mills PPI series ID: PCU331110331110; www.bls.gov/ppi/

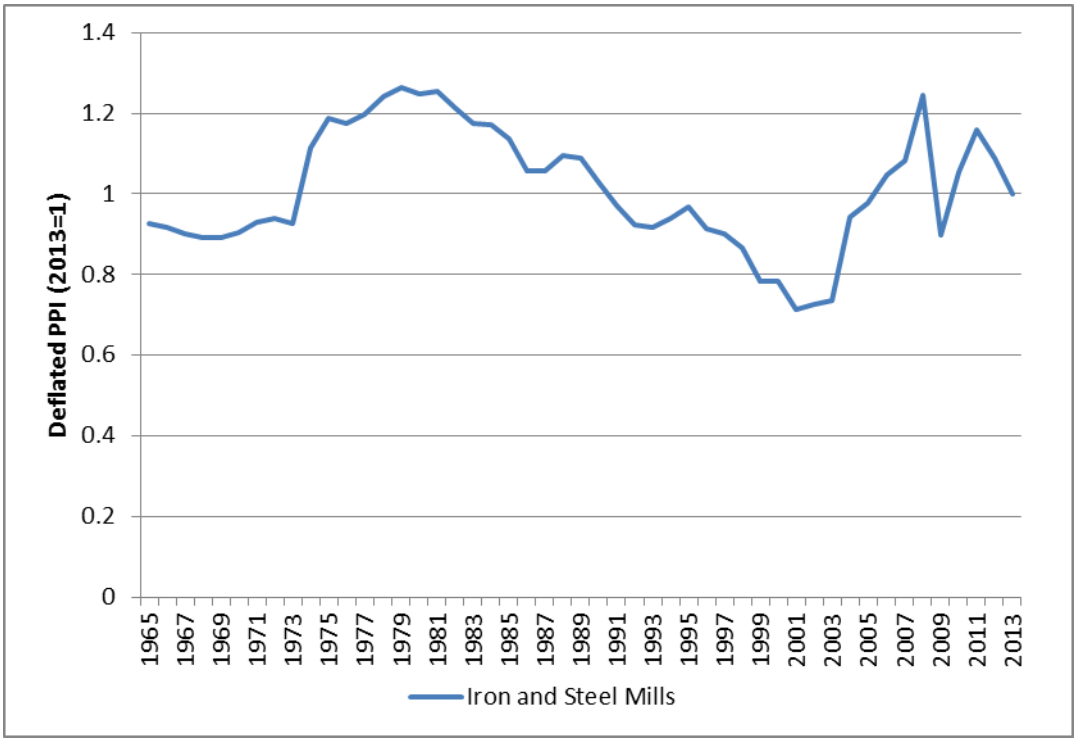

Figure 8.2.2 Deflated Iron and Steel Mills PPI from 1965 to 2013

DOE also applied a constant price trend to the manufacturer selling price of standby mode and off mode components for residential boilers.

8.2.1.5 Installation Cost

The installation cost is the cost to the consumer of installing the boiler. The cost of installation covers all labor and material costs associated with the replacement of an existing boiler or the installation of a boiler in a new home, as well as delivery of the new boiler, removal of the existing boiler, and any applicable permit fees. Higher efficiency boilers may require additional installation costs. DOE's analysis of installation costs estimated specific installation costs for each sample household based on building characteristics given in RECS 2009 and CBECS 2003.

DOE estimated the installation costs at each considered efficiency level using a variety of sources, including RS Means 2015 Residential Cost Data,[7] manufacturer literature, and information from expert consultants. DOE's analysis of installation costs accounted for regional differences in labor costs. For a detailed discussion of the development of installation costs, see appendix 8C.

DOE gave separate consideration to the cost of installing higher efficiency non-condensing boiler requiring special venting requirements, as well as condensing boilers in replacement cases and in new homes. DOE conducted a detailed analysis of installation costs when a non-condensing boiler is replaced with a higher efficiency non-condensing gas-fired

boiler requiring special venting requirements or condensing boiler, with particular attention to venting issues in replacement applications. The installation cost depends on the boiler installation location, which DOE determined using information from RECS 2009 and CBECS 2003.

DOE estimated basic installation costs that are applicable to both replacement and new home installations. These costs, which apply to all boilers, include putting in place and setting up the boiler, gas or oil piping, water piping, ductwork, electrical hookup for the thermostat, permitting, and removal or disposal fees.

For *replacement installations*, DOE included a number of additional costs ("adders") for a fraction of the sample households. For non-condensing boilers, these additional costs included updating flue vent connectors, vent resizing, chimney relining, and for a fraction of installations included the costs for a new stainless steel vent, as well as combustion air vent for direct vent installations (plastic venting), concealing vent pipes for indoor installations, addressing an orphaned water heater (by updating flue vent connectors, vent resizing, or chimney relining), and condensate removal. For condensing boilers, these additional costs included adding a new flue vent (plastic venting), combustion air vent for direct vent installations (plastic venting), concealing vent pipes for indoor installations, addressing an orphaned water heater (by updating flue vent connectors, vent resizing, or chimney relining), and condensate removal.

DOE also included installation adders for *new construction* installations. For non-condensing boilers, a new metal flue vent is the only adder, with the exception of non-condensing boilers requiring stainless steel venting. In addition to the stainless steel venting, these non-condensing boilers require combustion air vent for direct vent installations (plastic venting), accounting for a commonly vented water heater, and condensate removal. For condensing gas boilers, the adders include new flue vent (plastic venting), combustion air vent for direct vent installations (plastic venting), accounting for a commonly vented water heater, and condensate removal.

Table 8.2.7 presents the average installation costs for each residential boiler product class at each efficiency level examined. DOE assumed no additional installation cost for standby mode and off mode standards because the components are included with the boiler.

Table 8.2.7 Average Installation Costs for Residential Boilers (2014$)

Product Class	Efficiency Level	Installation Cost 2014$	Incremental Cost 2014$
Gas-Fired Hot Water Boiler	82% AFUE - Baseline	$4,288	-
	83% AFUE - Increased HX Area	$4,288	$0.00
	84% AFUE - Increased HX Area	$4,288	$0.00
	85% AFUE - Increased HX Area	$4,379	$91.01
	90% AFUE - Condensing Baseline	$4,397	$108.56
	92% AFUE - Increased HX Area	$4,397	$108.56
	96% AFUE - Max Tech	$4,397	$108.56
Gas-Fired Steam Boiler	80% AFUE - Baseline	$3,795	-
	82% AFUE - Increased HX Area	$3,819	$24.00
	83% AFUE - Max Tech	$3,846	$50.68
Oil-Fired Hot Water Boiler	84% AFUE - Baseline	$4,068	-
	85% AFUE - Increased HX Area	$4,068	$0.00
	86% AFUE - Increased HX Area	$4,068	$0.00
	91% AFUE - Condensing (Max Tech)	$4,510	$441.92
Oil-Fired Steam Boiler	82% AFUE - Baseline	$3,843	-
	84% AFUE - Increased HX Area	$3,843	$0.00
	85% AFUE - Increased HX Area	$3,843	$0.00
	86% AFUE - Max Tech	$3,843	$0.00

8.2.1.6 Total Installed Cost

The total installed cost is the sum of the product price and the installation cost. MSPs, markups, and sales taxes all can take on a variety of values, depending on location, so the resulting total installed cost for a particular efficiency level will not be a single-point value, but rather a distribution of values. Table 8.2.8 presents the average total installed cost for each residential boiler product class at each efficiency level examined.

Table 8.2.8 Average Total Installed Cost for Residential Boilers (2014$)

Product Class	Efficiency Level	Total Installed Cost 2014$	Incremental Cost 2014$
Gas-Fired Hot Water Boiler	82% AFUE - Baseline	$6,371	-
	83% AFUE - Increased HX Area	$6,387	$16
	84% AFUE - Increased HX Area	$6,402	$31
	85% AFUE - Increased HX Area	$6,649	$278
	90% AFUE - Condensing Baseline	$7,255	$884
	92% AFUE - Increased HX Area	$7,605	$1,234
	96% AFUE - Max Tech	$8,295	$1,924
Gas-Fired Steam Boiler	80% AFUE - Baseline	$6,313	-
	82% AFUE - Increased HX Area	$6,376	$64
	83% AFUE - Max Tech	$6,682	$370
Oil-Fired Hot Water Boiler	84% AFUE - Baseline	$8,049	-
	85% AFUE - Increased HX Area	$8,200	$151
	86% AFUE - Increased HX Area	$8,351	$302
	91% AFUE - Condensing (Max Tech)	$10,691	$2,642
Oil-Fired Steam Boiler	82% AFUE - Baseline	$7,886	-
	84% AFUE - Increased HX Area	$8,189	$304
	85% AFUE - Increased HX Area	$8,341	$455
	86% AFUE - Max Tech	$8,644	$759

8.2.2 Operating Cost Inputs

DOE defined the operating cost by the following equation:

$$OC = EC + RC + MC \qquad \textbf{Eq. 8.3}$$

Where:

OC = operating cost ($),
EC = energy cost associated with operating the product ($),
RC = repair cost associated with component failure ($), and
MC = annual maintenance cost for maintaining product operation ($).

The remainder of this section provides information about the variables that DOE used to calculate the operating cost for residential boilers. The annual energy costs of the product are computed from energy consumption per unit for the baseline and standard-compliant cases (efficiency level 2, 3, and so on), combined with the energy prices. Product lifetime, discount

rate, and compliance date of the standard are required for determining the operating cost and for establishing the operating cost present value.

8.2.2.1 Annual Energy Use Savings

For each key product class, DOE calculated the annual energy use savings for each sample household at each efficiency level as described in chapter 7.

DOE considered the possibility that some consumers may use a higher efficiency boiler more than a baseline one, thereby negating some or all of the energy savings from the more efficient equipment. Such change in behavior when operating costs decline is known as a (direct) rebound effect. The take-back in energy consumption associated with the rebound effect provides consumers with increased value (*e.g.,* more comfortable indoor temperature). DOE believes that, if it were able to monetize the increased value to consumers of the rebound effect, this value would be similar in value to the foregone energy savings. Therefore, the economic impacts on consumers with or without the rebound effect, as measured in the LCC analysis, are the same. The reduction in energy savings due to the rebound effect is accounted for when determining the national energy savings (NES) in the national impact analysis (NIA), as described in chapter 10.

8.2.2.2 Energy Prices

DOE derived average and marginal monthly energy prices for a number of geographic areas in the United States using the latest data from EIA and monthly energy price factors that it developed. Average energy prices are applied to the no-new-standards case energy use, while marginal prices are applied to the differential energy use from the higher efficiency options. This process then assigns an appropriate energy price to each household and commercial building in the sample, depending on its sector (residential or commercial) and location.

Derivation of Average and Marginal Monthly Prices

Derivation of Average Annual Energy Prices using EIA Data. DOE obtained the data for natural gas prices from EIA's Natural Gas Navigator,[8] which includes monthly natural gas prices by state for residential, commercial, and industrial customers. DOE derived 2012 annual electricity prices from EIA Form 826 data,[9] which includes energy prices by state. DOE calculated annual state electricity and natural gas prices by averaging monthly energy prices by state.

DOE collected 2012 average LPG prices from EIA's 2012 State Energy Consumption, Price, and Expenditures Estimates (SEDS).[10] SEDS includes annual LPG prices for residential, commercial, industrial, and transportation consumers by state.

For RECS 2009 or CBECS 2003 regions with more than one state, DOE weighted each state's average energy price by the total gas-fired and oil-fired boiler shipments by state from AHRI data.[11] See appendix 8D for the calculated annual energy prices in 2012.

Derivation of Average Monthly Energy Price Factors using EIA data. To determine monthly prices for use in the analysis, DOE developed monthly energy price factors for each fuel based on long-term price data. See appendix 8D for a description of the method. DOE multiplied the average 2012 annual prices by the monthly price factors for each fuel to derive prices for each month.

Seasonal Electricity and Natural Gas Marginal Price Factors using EIA data. Monthly electricity and natural gas prices were adjusted using seasonal marginal price factors to determine monthly marginal electricity and natural gas prices. These marginal energy prices were used to determine the cost to the consumer of the change in energy consumed. Because marginal price data is only available for electricity and natural gas, DOE only developed marginal monthly prices for these fuels. For LPG and fuel oil, DOE used average monthly prices. For a detailed discussion of the development of marginal energy price factors, see appendix 8D.

Table 8.2.9 through Table 8.2.14 show the residential average and marginal monthly natural gas and electricity prices. Average residential LPG and fuel oil prices and commercial prices are shown in appendix 8D.

Table 8.2.9 Residential Average Monthly Electricity Prices for 2013 Using Price Factors by RECS 2009 Regions (2014$/kWh)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	0.156	0.157	0.158	0.161	0.162	0.162	0.161	0.161	0.161	0.163	0.160	0.159
Massachusetts	0.150	0.151	0.151	0.151	0.153	0.157	0.152	0.154	0.156	0.154	0.152	0.156
New York	0.172	0.174	0.174	0.177	0.181	0.188	0.191	0.190	0.189	0.184	0.180	0.176
New Jersey	0.144	0.144	0.145	0.145	0.149	0.160	0.164	0.164	0.160	0.148	0.147	0.147
Pennsylvania	0.115	0.116	0.118	0.122	0.127	0.132	0.132	0.131	0.129	0.127	0.122	0.119
Illinois	0.092	0.097	0.100	0.105	0.109	0.110	0.109	0.107	0.108	0.107	0.101	0.094
Indiana, Ohio	0.102	0.105	0.109	0.115	0.120	0.121	0.119	0.119	0.119	0.118	0.114	0.107
Michigan	0.137	0.138	0.137	0.139	0.141	0.146	0.148	0.149	0.145	0.141	0.139	0.140
Wisconsin	0.126	0.130	0.128	0.132	0.134	0.135	0.132	0.132	0.134	0.133	0.132	0.129
Iowa, Minnesota, North Dakota, South Dakota	0.101	0.103	0.105	0.109	0.113	0.118	0.119	0.118	0.115	0.112	0.107	0.104
Kansas, Nebraska	0.091	0.095	0.097	0.102	0.106	0.117	0.118	0.119	0.117	0.105	0.101	0.095
Missouri	0.086	0.089	0.093	0.098	0.111	0.121	0.120	0.119	0.109	0.100	0.096	0.090
Virginia	0.096	0.098	0.101	0.105	0.110	0.112	0.112	0.112	0.110	0.107	0.103	0.098
Delaware, District of Columbia, Maryland	0.116	0.116	0.118	0.121	0.132	0.143	0.142	0.141	0.138	0.128	0.122	0.120
Georgia	0.099	0.103	0.106	0.107	0.112	0.120	0.121	0.123	0.117	0.110	0.105	0.100
North Carolina, South Carolina	0.101	0.103	0.105	0.109	0.109	0.107	0.110	0.110	0.112	0.114	0.108	0.104
Florida	0.107	0.108	0.109	0.110	0.109	0.108	0.109	0.109	0.110	0.110	0.111	0.109
Alabama, Kentucky, Mississippi	0.090	0.092	0.094	0.099	0.101	0.101	0.099	0.099	0.099	0.101	0.098	0.094
Tennessee	0.093	0.093	0.095	0.097	0.099	0.098	0.096	0.096	0.096	0.100	0.100	0.097
Arkansas, Louisiana, Oklahoma	0.084	0.087	0.089	0.090	0.093	0.094	0.095	0.095	0.096	0.096	0.090	0.087
Texas	0.102	0.103	0.106	0.109	0.111	0.115	0.115	0.115	0.114	0.113	0.108	0.106
Colorado	0.109	0.111	0.112	0.114	0.117	0.119	0.118	0.118	0.118	0.117	0.115	0.112
Idaho, Montana, Utah, Wyoming	0.095	0.096	0.096	0.097	0.100	0.103	0.104	0.103	0.103	0.103	0.099	0.098
Arizona	0.099	0.102	0.104	0.110	0.122	0.121	0.119	0.119	0.118	0.118	0.105	0.106
Nevada, New Mexico	0.108	0.110	0.111	0.113	0.115	0.116	0.116	0.117	0.115	0.117	0.112	0.111
California	0.156	0.152	0.151	0.151	0.156	0.160	0.163	0.163	0.157	0.150	0.156	0.158
Oregon, Washington	0.084	0.085	0.085	0.085	0.085	0.086	0.086	0.087	0.087	0.087	0.088	0.088
Alaska	0.167	0.169	0.173	0.175	0.180	0.179	0.183	0.181	0.178	0.178	0.176	0.174
Hawaii	0.345	0.346	0.346	0.349	0.354	0.359	0.362	0.365	0.364	0.370	0.369	0.367
West Virginia	0.087	0.088	0.091	0.093	0.096	0.094	0.093	0.093	0.095	0.097	0.094	0.090
United States	0.109	0.111	0.113	0.117	0.120	0.122	0.122	0.123	0.122	0.120	0.117	0.113

Table 8.2.10 Residential Average Monthly Natural Gas Prices for 2013 Using Price Factors by RECS 2009 Regions (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	13.88	13.97	14.17	14.01	14.66	15.92	17.77	18.18	17.52	15.52	14.96	14.57
Massachusetts	13.76	13.75	13.64	13.97	13.26	13.59	15.01	15.79	15.24	13.18	14.07	13.98
New York	12.79	12.57	12.77	13.35	14.86	17.00	17.89	16.83	16.50	14.50	12.80	11.98
New Jersey	10.64	10.52	10.55	10.76	11.45	12.56	13.10	13.05	12.86	11.86	11.17	10.84
Pennsylvania	11.35	11.46	11.69	12.23	13.77	15.98	17.70	18.18	17.23	14.08	12.33	11.67
Illinois	8.38	8.41	8.49	9.02	11.01	12.74	13.71	13.85	12.87	10.04	8.89	8.35
Indiana, Ohio	10.31	10.39	10.69	11.49	12.91	15.06	16.49	16.77	15.68	12.48	10.87	10.56
Michigan	8.60	8.62	8.73	9.17	10.26	11.72	12.97	13.39	12.35	10.25	9.26	8.93
Wisconsin	9.18	8.95	9.13	9.28	9.24	10.69	11.11	11.29	10.32	8.41	9.40	9.15
Iowa, Minnesota, North Dakota, South Dakota	8.52	8.37	8.51	8.68	9.87	11.66	12.53	12.90	12.05	9.57	8.94	8.50
Kansas, Nebraska	9.32	9.37	9.36	10.17	11.39	13.59	14.73	15.45	14.97	12.76	10.33	9.63
Missouri	11.06	11.08	11.23	12.59	14.59	18.05	20.69	21.90	20.40	17.25	13.40	11.80
Virginia	11.72	11.24	11.11	12.40	14.68	17.14	18.56	18.24	18.19	14.72	12.03	11.64
Delaware, District of Columbia, Maryland	11.36	11.21	11.50	12.70	14.64	16.70	17.86	17.82	17.14	13.87	12.11	11.57
Georgia	12.44	13.26	13.85	15.44	19.16	21.56	22.74	22.53	21.87	18.76	14.24	13.34
North Carolina, South Carolina	12.14	12.05	12.48	13.58	15.81	18.97	20.02	20.80	19.89	16.37	13.32	12.96
Florida	15.73	16.08	17.15	18.16	19.80	21.06	21.75	22.23	21.91	21.54	19.75	17.52
Alabama, Kentucky, Mississippi	10.38	10.45	10.70	11.98	14.14	15.96	16.65	17.21	16.45	13.78	11.46	10.93
Tennessee	9.75	9.89	9.94	10.85	11.93	13.76	14.68	15.11	14.48	13.10	10.97	10.26
Arkansas, Louisiana, Oklahoma	10.08	10.02	10.26	11.21	13.20	14.36	15.01	15.23	14.92	14.40	12.50	10.83
Texas	10.35	10.42	10.75	12.40	14.21	16.06	16.64	17.07	16.92	15.30	12.45	10.80
Colorado	7.45	7.55	7.81	8.05	8.98	11.46	11.58	12.26	11.32	8.94	8.06	7.62
Idaho, Montana, Utah, Wyoming	8.25	8.29	8.41	8.23	8.64	9.45	10.41	10.92	10.15	8.71	8.55	8.39
Arizona	12.61	13.03	13.51	14.89	16.67	18.49	20.15	20.85	20.17	18.71	15.80	13.62
Nevada, New Mexico	8.40	8.58	8.75	9.53	11.56	14.09	13.33	13.73	13.21	11.18	9.11	8.36
California	10.07	9.95	9.61	9.67	10.11	10.61	10.65	10.50	10.21	10.27	9.88	9.92
Oregon, Washington	10.89	11.05	11.09	11.42	11.95	12.63	13.65	14.19	13.77	12.35	11.53	11.25
Alaska	8.36	8.44	8.46	8.57	9.00	9.32	10.02	9.80	9.07	8.64	8.36	8.68
Hawaii	46.03	47.27	47.27	47.30	47.84	48.29	49.46	50.59	50.46	50.29	49.56	48.68
West Virginia	10.04	10.10	10.21	10.58	11.79	14.35	15.95	15.77	14.37	11.70	10.66	10.33
United States	9.99	10.04	10.18	10.72	11.83	13.33	14.14	14.42	13.79	11.82	10.68	10.19

Table 8.2.11 Residential Average Monthly LPG Prices for 2013 Using Monthly Price Factors by RECS 2009 Regions (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	29.65	29.95	30.11	30.13	30.60	30.90	31.00	30.81	30.78	30.92	30.61	30.59
Massachusetts	32.07	32.40	32.57	32.59	33.10	33.42	33.53	33.32	33.30	33.45	33.11	33.09
New York	31.21	31.53	31.70	31.72	32.21	32.53	32.63	32.43	32.41	32.55	32.23	32.20
New Jersey	31.84	32.17	32.34	32.36	32.86	33.19	33.29	33.09	33.06	33.21	32.88	32.85
Pennsylvania	29.14	29.44	29.59	29.61	30.07	30.37	30.47	30.28	30.25	30.39	30.08	30.06
Illinois	23.78	23.78	23.49	23.12	22.84	22.04	21.38	21.32	21.81	22.46	23.48	24.52
Indiana, Ohio	28.14	28.13	27.79	27.36	27.02	26.07	25.29	25.22	25.80	26.57	27.78	29.01
Michigan	25.75	25.74	25.43	25.04	24.73	23.86	23.15	23.08	23.62	24.32	25.42	26.55
Wisconsin	23.70	23.69	23.41	23.04	22.76	21.96	21.30	21.24	21.73	22.38	23.40	24.43
Iowa, Minnesota, North Dakota, South Dakota	24.27	24.26	23.97	23.60	23.31	22.49	21.82	21.75	22.26	22.92	23.96	25.02
Kansas, Nebraska	23.93	23.93	23.64	23.27	22.98	22.18	21.51	21.45	21.95	22.60	23.63	24.67
Missouri	24.32	24.32	24.02	23.65	23.36	22.54	21.86	21.80	22.31	22.97	24.01	25.08
Virginia	24.81	24.89	24.52	24.04	23.66	23.22	22.69	22.26	22.81	23.76	24.50	25.29
Delaware, District of Columbia, Maryland	34.63	34.74	34.22	33.56	33.03	32.40	31.66	31.06	31.84	33.16	34.19	35.30
Georgia	26.29	26.37	25.98	25.48	25.07	24.60	24.04	23.58	24.17	25.18	25.96	26.80
North Carolina, South Carolina	27.65	27.74	27.32	26.79	26.37	25.87	25.28	24.80	25.42	26.48	27.30	28.19
Florida	28.16	28.25	27.83	27.29	26.86	26.35	25.75	25.26	25.89	26.97	27.80	28.71
Alabama, Kentucky, Mississippi	24.60	24.68	24.31	23.84	23.46	23.02	22.49	22.07	22.62	23.56	24.29	25.08
Tennessee	30.03	30.13	29.67	29.10	28.64	28.10	27.46	26.94	27.61	28.76	29.65	30.61
Arkansas, Louisiana, Oklahoma	16.80	16.85	16.60	16.28	16.02	15.72	15.36	15.07	15.45	16.09	16.59	17.12
Texas	15.11	15.15	14.93	14.64	14.41	14.13	13.81	13.55	13.89	14.46	14.91	15.40
Colorado	26.49	26.54	26.09	25.49	24.88	24.17	23.30	23.00	23.91	25.34	26.16	27.18
Idaho, Montana, Utah, Wyoming	24.97	25.01	24.58	24.02	23.45	22.78	21.95	21.68	22.53	23.88	24.65	25.61
Arizona	31.48	31.54	31.00	30.29	29.56	28.72	27.68	27.33	28.41	30.11	31.08	32.29
Nevada, New Mexico	21.89	21.93	21.56	21.07	20.56	19.97	19.25	19.01	19.76	20.94	21.62	22.46
California	29.65	29.71	29.20	28.53	27.85	27.05	26.08	25.75	26.77	28.37	29.28	30.42
Oregon, Washington	27.67	27.72	27.25	26.63	25.99	25.24	24.33	24.03	24.98	26.47	27.32	28.39
Alaska	27.84	27.89	27.41	26.79	26.14	25.39	24.48	24.17	25.13	26.63	27.49	28.56
Hawaii	34.79	34.85	34.26	33.48	32.67	31.74	30.59	30.21	31.40	33.28	34.35	35.69
West Virginia	32.65	32.75	32.26	31.64	31.14	30.55	29.85	29.29	30.02	31.27	32.24	33.28
United States	18.31	18.42	18.30	18.17	18.19	17.82	17.02	16.63	17.14	17.69	18.26	18.81

Table 8.2.12 Residential Average Monthly Oil Prices for 2013 Using Monthly Price Factors by RECS 2009 Regions (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	27.60	28.01	27.81	27.57	27.40	27.22	26.79	26.75	27.60	28.31	28.78	29.08
Massachusetts	28.43	28.85	28.65	28.40	28.23	28.03	27.59	27.55	28.43	29.16	29.64	29.96
New York	28.53	28.95	28.75	28.50	28.33	28.13	27.69	27.65	28.53	29.26	29.75	30.06
New Jersey	29.36	29.79	29.58	29.33	29.15	28.95	28.49	28.46	29.36	30.11	30.61	30.94
Pennsylvania	29.09	29.51	29.31	29.06	28.88	28.68	28.23	28.19	29.09	29.83	30.33	30.65
Illinois	27.47	27.78	28.16	28.34	28.30	28.23	28.05	28.67	29.69	30.33	30.28	29.81
Indiana, Ohio	27.38	27.69	28.07	28.25	28.21	28.14	27.96	28.57	29.59	30.23	30.18	29.71
Michigan	27.40	27.71	28.10	28.27	28.23	28.16	27.98	28.60	29.61	30.25	30.21	29.73
Wisconsin	27.15	27.46	27.84	28.01	27.97	27.90	27.72	28.33	29.34	29.97	29.93	29.46
Iowa, Minnesota, North Dakota, South Dakota	27.51	27.82	28.20	28.38	28.34	28.27	28.09	28.71	29.73	30.37	30.33	29.85
Kansas, Nebraska	27.35	27.66	28.04	28.22	28.18	28.11	27.93	28.54	29.56	30.20	30.15	29.68
Missouri	26.95	27.25	27.63	27.80	27.76	27.69	27.51	28.12	29.12	29.75	29.71	29.24
Virginia	28.55	28.87	28.74	28.35	27.49	27.13	27.16	27.42	28.43	29.19	29.73	30.04
Delaware, District of Columbia, Maryland	29.31	29.63	29.50	29.10	28.21	27.85	27.88	28.15	29.18	29.97	30.52	30.84
Georgia	28.28	28.59	28.46	28.08	27.22	26.87	26.89	27.16	28.16	28.91	29.44	29.75
North Carolina, South Carolina	28.52	28.83	28.70	28.32	27.45	27.10	27.12	27.39	28.40	29.16	29.69	30.00
Florida	28.82	29.13	29.00	28.62	27.74	27.38	27.41	27.68	28.69	29.46	30.00	30.32
Alabama, Kentucky, Mississippi	28.40	28.71	28.58	28.20	27.34	26.98	27.01	27.27	28.28	29.03	29.57	29.88
Tennessee	29.09	29.41	29.28	28.89	28.01	27.64	27.67	27.94	28.97	29.75	30.29	30.61
Arkansas, Louisiana, Oklahoma	26.57	26.86	26.74	26.38	25.58	25.25	25.27	25.52	26.46	27.17	27.66	27.95
Texas	26.84	27.13	27.01	26.65	25.83	25.50	25.52	25.78	26.72	27.44	27.94	28.23
Colorado	23.82	24.23	25.30	25.75	25.70	25.61	25.21	25.26	26.12	26.54	26.52	25.91
Idaho, Montana, Utah, Wyoming	23.84	24.25	25.33	25.77	25.73	25.64	25.24	25.29	26.14	26.57	26.55	25.94
Arizona	27.62	28.10	29.34	29.86	29.81	29.70	29.24	29.30	30.29	30.78	30.76	30.05
Nevada, New Mexico	25.42	25.86	27.00	27.48	27.43	27.33	26.91	26.96	27.87	28.32	28.31	27.66
California	28.01	28.49	29.76	30.28	30.23	30.12	29.66	29.71	30.72	31.21	31.19	30.48
Oregon, Washington	27.54	28.02	29.26	29.77	29.72	29.61	29.16	29.21	30.20	30.69	30.67	29.97
Alaska	26.07	26.51	27.69	28.18	28.13	28.03	27.60	27.65	28.58	29.05	29.03	28.36
Hawaii	27.10	27.57	28.79	29.30	29.25	29.14	28.69	28.74	29.72	30.20	30.18	29.49
West Virginia	28.82	29.13	29.00	28.62	27.74	27.38	27.41	27.68	28.69	29.46	30.00	30.32
United States	28.46	28.86	28.74	28.54	28.30	28.06	27.67	27.72	28.65	29.37	29.82	30.05

Table 8.2.13 Residential Marginal Monthly Electricity Prices for 2013 Using Marginal Price Factors by RECS 2009 Regions (2014$/kWh)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	0.150	0.151	0.153	0.149	0.150	0.150	0.149	0.149	0.149	0.151	0.154	0.153
Massachusetts	0.156	0.157	0.157	0.143	0.145	0.149	0.145	0.146	0.148	0.146	0.158	0.162
New York	0.157	0.159	0.159	0.202	0.206	0.214	0.217	0.217	0.216	0.210	0.164	0.161
New Jersey	0.141	0.142	0.143	0.174	0.178	0.192	0.197	0.197	0.192	0.177	0.145	0.145
Pennsylvania	0.096	0.097	0.098	0.131	0.136	0.141	0.141	0.140	0.138	0.136	0.101	0.099
Illinois	0.066	0.069	0.071	0.100	0.104	0.105	0.104	0.103	0.103	0.103	0.071	0.067
Indiana, Ohio	0.077	0.079	0.082	0.120	0.124	0.126	0.123	0.123	0.124	0.123	0.086	0.080
Michigan	0.131	0.132	0.131	0.156	0.159	0.164	0.166	0.167	0.163	0.158	0.133	0.134
Wisconsin	0.112	0.116	0.114	0.134	0.136	0.137	0.134	0.135	0.136	0.136	0.117	0.115
Iowa, Minnesota, North Dakota, South Dakota	0.086	0.088	0.089	0.119	0.124	0.129	0.130	0.129	0.126	0.122	0.092	0.089
Kansas, Nebraska	0.066	0.069	0.071	0.123	0.128	0.142	0.143	0.143	0.142	0.127	0.074	0.070
Missouri	0.066	0.068	0.071	0.121	0.137	0.149	0.147	0.146	0.133	0.123	0.073	0.069
Virginia	0.080	0.082	0.084	0.114	0.119	0.121	0.122	0.122	0.119	0.116	0.086	0.082
Delaware, District of Columbia, Maryland	0.107	0.107	0.109	0.141	0.154	0.166	0.164	0.164	0.161	0.148	0.112	0.110
Georgia	0.084	0.087	0.090	0.126	0.131	0.141	0.143	0.144	0.138	0.129	0.089	0.085
North Carolina, South Carolina	0.084	0.086	0.087	0.106	0.106	0.104	0.107	0.107	0.108	0.111	0.090	0.086
Florida	0.101	0.102	0.103	0.112	0.110	0.110	0.110	0.111	0.111	0.112	0.105	0.103
Alabama, Kentucky, Mississippi	0.076	0.078	0.080	0.096	0.098	0.098	0.096	0.097	0.097	0.099	0.083	0.079
Tennessee	0.079	0.080	0.081	0.092	0.093	0.092	0.091	0.091	0.091	0.095	0.086	0.083
Arkansas, Louisiana, Oklahoma	0.069	0.071	0.073	0.094	0.096	0.098	0.098	0.099	0.100	0.100	0.074	0.071
Texas	0.092	0.093	0.096	0.113	0.115	0.119	0.119	0.119	0.118	0.118	0.098	0.096
Colorado	0.087	0.089	0.089	0.127	0.130	0.132	0.131	0.132	0.132	0.130	0.092	0.089
Idaho, Montana, Utah, Wyoming	0.087	0.088	0.088	0.100	0.104	0.107	0.108	0.107	0.107	0.107	0.090	0.089
Arizona	0.083	0.086	0.088	0.116	0.128	0.127	0.126	0.125	0.125	0.124	0.088	0.089
Nevada, New Mexico	0.096	0.098	0.099	0.126	0.128	0.129	0.130	0.131	0.129	0.131	0.100	0.099
California	0.174	0.170	0.169	0.182	0.188	0.193	0.197	0.196	0.189	0.180	0.175	0.177
Oregon, Washington	0.079	0.080	0.080	0.073	0.073	0.074	0.075	0.075	0.075	0.075	0.082	0.082
Alaska	0.151	0.153	0.156	0.150	0.154	0.154	0.157	0.155	0.152	0.153	0.159	0.157
Hawaii	0.333	0.334	0.333	0.474	0.482	0.488	0.492	0.496	0.495	0.503	0.356	0.354
West Virginia	0.075	0.076	0.078	0.086	0.089	0.087	0.086	0.086	0.088	0.090	0.080	0.077
United States	0.092	0.094	0.096	0.125	0.128	0.131	0.131	0.132	0.131	0.129	0.099	0.096

Table 8.2.14 Residential Marginal Monthly Natural Gas Prices for 2013 Using Marginal Price Factors by RECS 2009 Regions (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	13.04	13.12	13.31	11.58	12.12	13.16	14.68	15.03	14.48	12.83	14.05	13.68
Massachusetts	14.33	14.32	14.21	12.26	11.64	11.93	13.17	13.86	13.38	11.57	14.65	14.56
New York	11.32	11.13	11.30	9.78	10.89	12.45	13.11	12.33	12.09	10.63	11.33	10.61
New Jersey	10.46	10.34	10.37	8.95	9.52	10.45	10.90	10.85	10.70	9.87	10.98	10.65
Pennsylvania	10.54	10.65	10.85	8.66	9.75	11.31	12.54	12.88	12.20	9.97	11.45	10.83
Illinois	8.01	8.04	8.12	5.93	7.24	8.38	9.02	9.11	8.47	6.60	8.50	7.98
Indiana, Ohio	9.45	9.53	9.80	7.80	8.77	10.23	11.20	11.39	10.64	8.47	9.96	9.68
Michigan	8.35	8.37	8.48	7.12	7.96	9.10	10.07	10.40	9.59	7.96	8.99	8.67
Wisconsin	9.01	8.79	8.97	7.29	7.26	8.40	8.73	8.87	8.11	6.61	9.24	8.99
Iowa, Minnesota, North Dakota, South Dakota	8.29	8.14	8.28	6.14	6.98	8.24	8.86	9.13	8.52	6.77	8.69	8.27
Kansas, Nebraska	8.72	8.77	8.76	6.80	7.62	9.08	9.85	10.32	10.01	8.53	9.67	9.01
Missouri	8.93	8.94	9.07	7.18	8.32	10.29	11.80	12.48	11.63	9.83	10.82	9.52
Virginia	11.18	10.72	10.60	8.27	9.79	11.44	12.38	12.17	12.14	9.82	11.47	11.10
Delaware, District of Columbia, Maryland	10.53	10.40	10.66	8.42	9.71	11.07	11.84	11.82	11.37	9.20	11.23	10.72
Georgia	10.87	11.58	12.09	8.46	10.50	11.82	12.46	12.35	11.99	10.28	12.44	11.65
North Carolina, South Carolina	11.23	11.14	11.54	8.81	10.26	12.32	13.00	13.50	12.91	10.63	12.32	11.98
Florida	12.75	13.03	13.90	11.56	12.60	13.41	13.85	14.15	13.95	13.72	16.00	14.20
Alabama, Kentucky, Mississippi	8.92	8.98	9.20	7.87	9.29	10.48	10.94	11.30	10.81	9.05	9.84	9.39
Tennessee	9.06	9.19	9.24	7.87	8.66	9.99	10.66	10.97	10.52	9.51	10.20	9.53
Arkansas, Louisiana, Oklahoma	8.38	8.33	8.53	7.02	8.27	8.99	9.40	9.54	9.34	9.02	10.39	9.00
Texas	8.69	8.75	9.02	7.29	8.35	9.44	9.78	10.03	9.94	8.99	10.46	9.06
Colorado	6.67	6.75	6.99	5.46	6.09	7.77	7.86	8.32	7.68	6.07	7.22	6.82
Idaho, Montana, Utah, Wyoming	7.75	7.78	7.89	6.85	7.19	7.86	8.67	9.09	8.44	7.25	8.02	7.87
Arizona	10.69	11.05	11.45	9.48	10.61	11.77	12.83	13.27	12.84	11.91	13.39	11.54
Nevada, New Mexico	7.63	7.79	7.94	6.39	7.75	9.44	8.94	9.20	8.85	7.49	8.27	7.59
California	10.90	10.78	10.41	8.04	8.41	8.82	8.86	8.73	8.49	8.54	10.70	10.74
Oregon, Washington	10.21	10.35	10.39	9.59	10.03	10.60	11.46	11.92	11.56	10.37	10.81	10.54
Alaska	8.20	8.28	8.30	7.44	7.82	8.10	8.70	8.51	7.87	7.50	8.20	8.51
Hawaii	46.84	48.10	48.11	36.59	37.01	37.36	38.27	39.14	39.04	38.91	50.44	49.54
West Virginia	9.60	9.66	9.76	8.27	9.22	11.22	12.47	12.33	11.24	9.15	10.20	9.88
United States	9.43	9.49	9.61	7.74	8.55	9.63	10.22	10.41	9.97	8.54	10.09	9.62

Household Energy Price Adjustment Factor

RECS 2009 and CBECS 2003 report the total annual consumption and expenditure of each energy use type. To take into account that household energy prices vary inside a geographical area, DOE developed an adjustment factor based on the reported average energy price in RECS 2009 and CBECS 2003 for each building divided by the average energy price in

the geographical region in RECS 2009 and CBECS 2003. This factor was then multiplied times the monthly price developed above to determine the household energy price. Appendix 8D includes more details.

Energy Price Trends

To arrive at prices in future years, DOE multiplied the prices described in the preceding section by the forecasts of annual average price changes in EIA's *AEO 2015*. Figure 8.2.3 shows the national residential energy price factor trends. To estimate the trend after 2040, DOE used the average rate of change during 2030–2040. DOE applied the projected energy price for each of the nine census divisions to each building in the sample based on the building's location. Appendix 8D includes more details.

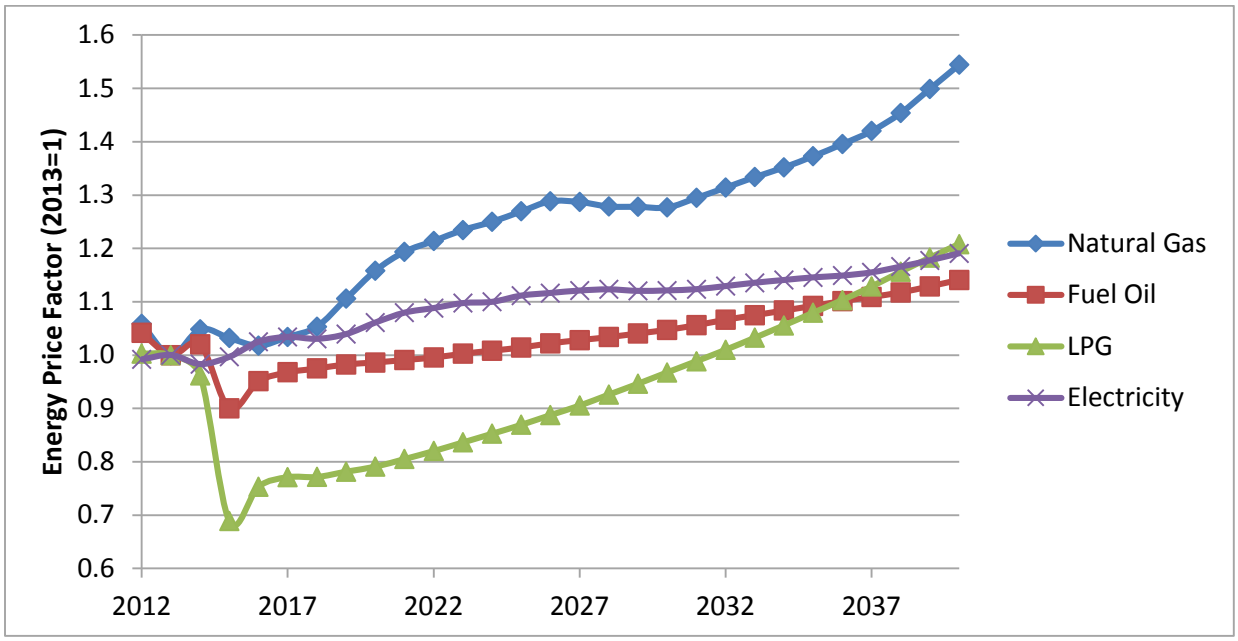

Figure 8.2.3 Projected National Commercial Energy Price Factors, AEO 2015 (Reference Case)

Summary

Table 8.2.15 and Table 8.2.16 present the average and marginal fuel and electricity prices for AFUE standards and for standby mode and off mode standards, respectively.

Table 8.2.15 Average Shipment Weighted Average and Marginal Fuel Prices in 2021 (AFUE Standards, 2014$)

Product Class	Fuel* *$/MMBtu*		Electricity Price *$/kWh*	
	Average	Marginal	Average	Marginal
Gas-Fired Hot Water Boiler	15.15	13.86	0.167	0.164
Gas-Fired Steam Boiler	15.04	13.52	0.169	0.167
Oil-Fired Hot Water Boiler	23.33	23.33	0.172	0.169
Oil-Fired Steam Boiler	23.50	23.50	0.177	0.175
Electric Hot Water Boiler	32.75	30.92	0.113	0.109
Electric Steam Boiler	33.85	31.84	0.117	0.113

* Includes both natural gas and LPG for gas-fired boilers.

Table 8.2.16 Average Shipment Weighted Average and Marginal Electricity Prices in 2021 (Standby Mode and Off Mode Standards, 2014$)

Product Class	Electricity Price *$/MMBtu*	
	Average	Marginal
Gas-Fired Hot Water Boiler	0.171	0.176
Gas-Fired Steam Boiler	0.173	0.179
Oil-Fired Hot Water Boiler	0.175	0.177
Oil-Fired Steam Boiler	0.180	0.184
Electric Hot Water Boiler	0.115	0.118
Electric Steam Boiler	0.119	0.123

8.2.2.3 Repair Cost

The repair cost is the cost to the consumer for replacing or repairing components in the residential boiler that have failed. DOE considered the repair of the controls and gas valve, replacement of the inducer fan, and heat exchanger repair in the repair cost. DOE based the heat exchanger repair cost on warranty and lifetime information. DOE assumed that condensing boilers have higher repair costs than non-condensing boilers. The repair costs at each considered efficiency level and the time of the repair were based on *2015 RS Means Facilities Maintenance and Repair Data*,[12] a report from the Gas Research Institute (GRI),[13] and data from Burnham. DOE also included additional repair costs for higher efficiency levels (*i.e.*, condensing boilers). DOE accounted for regional differences in labor costs. DOE did not account for additional repair cost related to standby mode and off mode. For a detailed discussion of the development of repair costs and sensitivity analysis, see appendix 8E.

Table 8.2.17 shows the annualized repair cost estimates for each product class.

Table 8.2.17 Annualized Repair Cost for Residential Boilers

Product Class	Efficiency Level	Annualized Repair Cost 2014$	Incremental Cost 2014$
Gas-Fired Hot Water Boiler	82% AFUE - Baseline	$5.95	-
	83% AFUE - Increased HX Area	$5.95	$0.00
	84% AFUE - Increased HX Area	$5.95	$0.00
	85% AFUE - Increased HX Area	$7.83	$1.87
	90% AFUE - Condensing Baseline	$20.03	$14.08
	92% AFUE - Increased HX Area	$20.43	$14.48
	96% AFUE - Max Tech	$21.22	$15.27
Gas-Fired Steam Boiler	80% AFUE - Baseline	$6.16	-
	82% AFUE - Increased HX Area	$6.37	$0.21
	83% AFUE - Max Tech	$6.64	$0.48
Oil-Fired Hot Water Boiler	84% AFUE - Baseline	$5.96	-
	85% AFUE - Increased HX Area	$5.96	$0.00
	86% AFUE - Increased HX Area	$5.96	$0.01
	91% AFUE - Condensing (Max Tech)	$23.63	$17.67
Oil-Fired Steam Boiler	82% AFUE - Baseline	$6.08	-
	84% AFUE - Increased HX Area	$6.08	$0.00
	85% AFUE - Increased HX Area	$6.08	$0.00
	86% AFUE - Max Tech	$6.09	$0.01

8.2.2.4 Maintenance Cost

The maintenance cost is the routine cost to the consumer of maintaining product operation. DOE included increased maintenance costs for condensing products. Table 8.2.18 shows the annualized maintenance cost estimates for each product class.

Labor hours and costs for annual maintenance were estimated using *2015 RS Means Facilities Maintenance and Repair Data*. The frequency with which the maintenance occurs was derived from a consumer survey[14] on the frequency with which owners of different types of boilers perform maintenance. For condensing boilers, DOE included additional labor hours to inspect condensate withdrawal system and replacement of condensate neutralizer filter. In addition, for condensing oil-fired boilers, DOE included additional labor hours to clean the secondary heat exchanger in areas not using low sulfur fuel oil. DOE did not consider additional maintenance cost related to standby mode and off mode. For a detailed discussion of the development of maintenance costs, see appendix 8E.

Table 8.2.18 Annualized Maintenance Cost for Residential Boilers (2014$)

Product Class	Efficiency Level	Annualized Maintenance Cost 2014$	Incremental Cost 2014$
Gas-Fired Hot Water Boiler	82% AFUE - Baseline	$88	-
	83% AFUE - Increased HX Area	$88	$0.00
	84% AFUE - Increased HX Area	$88	$0.00
	85% AFUE - Increased HX Area	$88	$0.00
	90% AFUE - Condensing Baseline	$92	$3.55
	92% AFUE - Increased HX Area	$92	$3.55
	96% AFUE - Max Tech	$92	$3.55
Gas-Fired Steam Boiler	80% AFUE - Baseline	$87	-
	82% AFUE - Increased HX Area	$87	$0.00
	83% AFUE - Max Tech	$87	$0.00
Oil-Fired Hot Water Boiler	84% AFUE - Baseline	$135	-
	85% AFUE - Increased HX Area	$135	$0.00
	86% AFUE - Increased HX Area	$135	$0.00
	91% AFUE - Condensing (Max Tech)	$141	$5.86
Oil-Fired Steam Boiler	82% AFUE - Baseline	$132	-
	84% AFUE - Increased HX Area	$132	$0.00
	85% AFUE - Increased HX Area	$132	$0.00
	86% AFUE - Max Tech	$132	$0.00

8.2.2.5 Lifetime

DOE defines lifetime as the age when a product is retired from service. DOE used national survey data, along with manufacturer shipment data, to calculate the distribution of residential boiler lifetimes. DOE also conducted a sensitivity analysis to determine the impact of changing the reference lifetime on LCC results. DOE used the same lifetimes for AFUE standards and standby mode and off mode standards. For a detailed discussion of the development of boiler lifetime, see appendix 8F.

Based on data from the 2013 American Housing Survey[15] and data from the AHRI contractor survey, DOE estimated that the average lifetimes are 26.5 years for hot water gas-fired boilers, 23.6 years for steam gas-fired boilers, 24.7 years for hot water oil-fired boilers, and 19.2 years for steam oil-fired boilers. Because DOE had no data on the lifetime of electric boilers, it assumed that electric boilers have the same lifetime as gas-fired boilers. Table 8.2.19 shows the Weibull distribution parameters alpha, beta and the location, as well as the average and median lifetime for each product class. DOE assumed that the lifetime of a residential boiler is the same across all efficiency levels for each product class. DOE included additional repair costs for condensing boilers that would likely allow a similar lifetime as non-condensing boilers by

assuming different service lifetimes for heat exchangers for condensing boilers and non-condensing boilers based on warranty data from product literature and survey data provided by stakeholders. To assess the impact of lifetime on the LCC results, DOE conducted a lifetime sensitivity analysis, which is presented in appendix 8F.

Table 8.2.19 Lifetime Parameters for Residential Boilers

Product Class	Weibull Parameters			Lifetime	
	Alpha (scale)	Beta (shape)	Location (delay)	Average	Median
Gas-Fired Hot Water Boiler	28.87	2.39	1.00	26.50	25.55
Gas-Fired Steam Boiler	25.51	2.39	1.00	23.38	22.72
Oil-Fired Hot Water Boiler	26.77	2.39	1.00	24.84	24.15
Oil-Fired Steam Boiler	20.63	2.39	1.00	19.25	18.68
Electric Hot Water Boiler	28.87	2.39	1.00	26.50	25.55
Electric Steam Boiler	25.51	2.39	1.00	23.38	22.72

8.2.2.6 Discount Rates

The discount rate is the rate at which future expenditures and savings are discounted to establish their present value. DOE estimated discount rates separately for residential and commercial end users. For residential end users, DOE calculated discount rates as the weighted average real interest rate across consumer debt and equity holdings. For commercial end users, DOE calculated commercial discount rates as the weighted average cost of capital (WACC), using the Capital Asset Pricing Model (CAPM).

Discount Rates for Residential Applications

The discount rate is the rate at which future savings and expenditures are discounted to establish their present value. DOE used publicly available data (the Federal Reserve Board's *Survey of Consumer Finance*s) to estimate a consumer's opportunity cost of funds related to appliance energy cost savings and maintenance costs. The discount rate value is applied in the LCC to future year energy cost savings and non-energy operations and maintenance costs to present the estimated net life-cycle cost and life-cycle cost savings. DOE notes that the discount rate used in the LCC analysis is distinct from an implicit discount rate, as it is not used to model consumer purchase decisions. The opportunity cost of funds in this case may include interest payments on debt and interest returns on assets.

DOE estimated separate discount rate distributions for six income groups, divided based on income percentile as reported in the Federal Reserve Board's *Survey of Consumer Finance*s (*SCF*).[16] These income groups are listed in Table 8.2.20. This disaggregation reflects the fact that low and high income consumers tend to have substantially different shares of debt and asset types, as well as facing different rates on debts and assets. Summaries of shares and rates presented in this chapter are averages across the entire population.

Table 8.2.20 Definitions of Income Groups

Income Group	Percentile of Income
1	1st to 20th
2	21st to 40th
3	41st to 60th
4	61st to 80th
5	81st to 90th
6	91th to 99th

Sources: Federal Reserve Board. *Survey of Consumer Finances (SCF)* for 1995, 1998, 2001, 2004, 2007, 2010, and 2013.

Shares of Debt and Asset Classes

DOE's approach involved identifying all relevant household debt or asset classes in order to approximate a consumer's opportunity cost of funds related to appliance energy cost savings and maintenance costs. The approach assumes that in the long term, consumers are likely to draw from or add to their collection of debt and asset holdings approximately in proportion to their current holdings when future expenditures are required or future savings accumulate. DOE has included several previously excluded debt types (*i.e.,* vehicle and education loans, mortgages, all forms of home equity loan) in order to better account for all of the options available to consumers.

The average share of total debt plus equity and the associated rate of each asset and debt type are used to calculate a weighted average discount rate for each SCF household (Table 8.2.21). The household-level discount rates are then aggregated to form discount rate distributions for each of the six income groups. Note that previously DOE performed aggregation of asset and debt types over households by summing the dollar value across all households and then calculating shares. Weighting by dollar value gave disproportionate influence to the asset and debt shares and rates of higher income consumers. DOE has shifted to a household-level weighting to more accurately reflect the average consumer in each income group.

DOE estimated the average percentage shares of the various types of debt and equity using data from the *SCF* for 1995, 1998, 2001, 2004, 2007, 2010, and 2013.[e] DOE derived the household-weighted mean percentages of each source of financing throughout the years surveyed. DOE posits that these long-term averages are most appropriate to use in its analysis.

[e] Note that two older versions of the *SCF* are also available (1989 and 1992); these surveys are not used in this analysis because they do not provide all of the necessary types of data (*e.g.*, credit card interest rates, *etc.*). DOE feels that the 18-year span covered by the seven surveys included is sufficiently representative of recent debt and equity shares and interest rates.

Table 8.2.21 Types of Household Debt and Equity by Percentage Shares

Type of Debt or Equity	Income Group					
	1	2	3	4	5	6
Debt:						
Mortgage	18.9%	24.1%	33.1%	38.1%	39.3%	25.0%
Home equity loan	3.1%	3.3%	2.6%	3.6%	4.5%	7.2%
Credit card	15.3%	13.0%	11.8%	8.7%	6.0%	2.7%
Other installment loan	25.1%	20.6%	17.3%	13.2%	9.6%	4.7%
Other residential loan	0.7%	0.6%	0.6%	0.7%	1.0%	1.2%
Other line of credit	1.6%	1.5%	1.3%	1.5%	2.1%	1.8%
Equity:						
Savings account	18.5%	16.0%	12.7%	10.6%	10.4%	7.9%
Money market account	3.6%	4.5%	4.0%	4.5%	5.0%	8.6%
Certificate of deposit	7.0%	7.8%	5.5%	5.0%	4.4%	4.2%
Savings bond	1.8%	1.7%	1.9%	2.2%	1.7%	1.1%
Bonds	0.2%	0.4%	0.5%	0.7%	0.8%	3.8%
Stocks	2.3%	3.1%	4.4%	5.7%	7.6%	15.8%
Mutual funds	2.1%	3.5%	4.3%	5.7%	7.6%	15.9%
Total	100.0	100.0	100.0	100.0	100.0	100.0

Sources: Federal Reserve Board. *Survey of Consumer Finances (SCF)* for 1995, 1998, 2001, 2004, 2007, 2010, and 2013.

Rates for Types of Debt

DOE estimated interest rates associated with each type of debt. The source for interest rates for mortgages, loans, credit cards, and lines of credit was the *SCF* for 1995, 1998, 2001, 2004, 2007, 2010 and 2013, which associates an interest rate with each type of debt for each household in the survey.

In calculating effective interest rates for home equity loans and mortgages, DOE accounted for the fact that interest on both such loans is tax deductible by using the applicable marginal tax rate for each income group. This rate corresponds to the interest rate after deduction of mortgage interest for income tax purposes[17] and after adjusting for inflation[18] (using the Fisher formula).[f] For example, a 6 percent nominal mortgage rate has an effective nominal rate of 5.5 percent for a household at the 25 percent marginal tax rate. When adjusted for an inflation rate of 2 percent, the effective real rate becomes 2.45 percent.

[f] Fisher formula is given by: Real Interest Rate = [(1 + Nominal Interest Rate) / (1 + Inflation Rate)] – 1.

Table 8.2.22 shows the household-weighted average effective real rates by income group. Because the interest rates for each type of household debt reflect economic conditions throughout numerous years and various phases of economic growth and recession, they are expected to be representative of rates in effect in 2021.

Table 8.2.22 Average Real Effective Interest Rates for Household Debt

Type of Debt	Income Group					
	1	2	3	4	5	6
Mortgage	3.36%	3.26%	3.13%	2.93%	2.78%	2.59%
Home equity loan	3.97%	4.17%	3.96%	3.81%	3.50%	3.09%
Credit card	11.82%	11.95%	11.12%	10.61%	10.07%	9.87%
Other installment loan	7.02%	8.71%	7.02%	6.25%	6.12%	4.81%
Other residential loan	4.87%	4.71%	4.66%	4.79%	4.54%	3.90%
Other line of credit	9.85%	10.03%	12.06%	8.31%	8.01%	6.30%

Sources: Federal Reserve Board. *Survey of Consumer Finances (SCF)* for 1995, 1998, 2001, 2004, 2007, 2010, and 2013.

Rates for Types of Assets

No similar rate data are available from the *SCF* for classes of assets, so DOE derived asset interest rates from various sources of 30-year national historical data (1985-2014). The interest rates associated with certificates of deposit,[19] savings bonds,[20] and bonds (AAA corporate bonds)[21] were collected from Federal Reserve Board time-series data. Rates on money market accounts came from Cost of Savings Index data.[22] Rates on savings accounts were estimated as one half of the rate for money market accounts, based on recent differentials between the return to each of these assets. The rates for stocks are the annual returns on the Standard and Poor's.[23] Rates for mutual funds are a weighted average of the stock rates (two-thirds weight) and the bond rates (one-third weight) in each year. DOE assumed rates on checking accounts to be zero.

DOE adjusted the nominal rates to real rates using the annual inflation rate for each year. Average nominal and real interest rates for the classes of household assets are listed in Table 8.2.23. Because the interest and return rates for each type of asset reflect economic conditions throughout numerous years, they are expected to be representative of rates that may be in effect in 2021. For each type, DOE developed a distribution of rates, as shown in appendix 8G.

Table 8.2.23 Average Real Interest Rates for Household Equity

Type of Equity	Average Real Rate %
Savings accounts	0.9
Money market accounts	1.7
Certificates of deposit	2.0
Savings and government bonds	3.2
State and local government bonds	2.7
Mortgage backed and Corporate bonds	4.0
Stocks	9.7
Mutual funds	7.5

Discount Rate Calculation and Summary

Using the asset and debt data discussed above, DOE calculated discount rate distributions for each income group as follows. First, DOE calculated the discount rate for each consumer in each of the six versions of the *SCF*, using the following formula:

$$DR_i = \sum_j Share_{i,j} \times Rate_{i,j}$$

Eq. 8.4

Where:

DR_i = discount rate for consumer i,
$Share_{i,j}$ = share of asset or debt type j for consumer i, and
$Rate_{i,j}$ = real interest rate or rate of return of asset or debt type j for consumer i.

The rate for each debt type is drawn from the *SCF* data for each household. The rate for each asset type is drawn from the distributions described above.

Once the real discount rate was estimated for each consumer, DOE compiled the distribution of discount rates in each survey by income group by calculating the proportion of consumers with discount rates in bins of 1 percent increments, ranging from 0-1 percent to greater than 30 percent. Giving equal weight to each survey, DOE compiled the six-survey distribution of discount rates.

Table 8.2.24 presents the average real effective discount rate and its standard deviation for each of the six income groups. To account for variation among households, DOE sampled a rate for each RECS household from the distributions for the appropriate income group. (RECS provides household income data.) Appendix 8G presents the full probability distributions for each income group that DOE used in the LCC and PBP analysis.

Table 8.2.24 Average Real Effective Discount

Income Group	Discount Rate (%)
1	4.88
2	5.08
3	4.67
4	3.95
5	3.68
6	3.49
Overall Average	4.43

Discount Rates for Commercial Applications

The commercial discount rate is the rate at which future operating costs are discounted to establish their present value in the LCC analysis. The discount rate value is applied in the LCC to future year energy costs and non-energy operations and maintenance costs to calculate the estimated net life-cycle cost of products of various efficiency levels and life-cycle cost savings as compared to the baseline for a representative sample of commercial end users.

DOE's method views the purchase of a higher efficiency appliance as an investment that yields a stream of energy cost savings. DOE derived the discount rates for the LCC analysis by estimating the cost of capital for companies that purchase residential boilers. The weighted average cost of capital (WACC) is commonly used to estimate the present value of cash flows to be derived from a typical company project or investment. Most companies use both debt and equity capital to fund investments, so their cost of capital is the weighted average of the cost to the firm of equity and debt financing, as estimated from financial data for publicly traded firms in the sectors that purchase residential boilers.[24]

Damodaran Online, a widely used source of information about company debt and equity financing, was used as the primary source of data for this analysis.[25] Companies included in the Damodaran Online database were assigned to the aggregate categories listed below:

- Retail
- Property Owners
- Medical Services
- Industrial
- Lodging
- Food Service
- Offices
- State and Local Government, Education
- Federal Government
- Other

DOE estimated the cost of equity using the capital asset pricing model (CAPM).[26] The CAPM assumes that the cost of equity (k_e) for a particular company is proportional to the systematic risk faced by that company, where high risk is associated with a high cost of equity

and low risk is associated with a low cost of equity. The systematic risk facing a firm is determined by several variables: the risk coefficient of the firm (β), the expected return on risk-free assets (R_f), and the equity risk premium (ERP). The risk coefficient of the firm indicates the risk associated with that firm relative to the price variability in the stock market. The expected return on risk-free assets is defined by the yield on long-term government bonds. The ERP represents the difference between the expected stock market return and the risk-free rate. The cost of equity financing is estimated using the following equation, where the variables are defined as above:

$$k_e = R_f + (\beta \times ERP)$$

Eq. 8.5

Where:

k_e = cost of equity,
R_f = expected return on risk-free assets,
β = risk coefficient of the firm, and
ERP = equity risk premium.

Several parameters of the cost of capital equations can vary substantially over time; therefore, the estimates can vary with the time period over which data is selected and the technical details of the data averaging method. For guidance on the time period for selecting and averaging data for key parameters and the averaging method, DOE used Federal Reserve methodologies for calculating these parameters. In its use of the CAPM, the Federal Reserve uses a forty-year period for calculating discount rate averages, utilizes the gross domestic product price deflator for estimating inflation, and considers the best method for determining the risk-free rate as one where "the time horizon of the investor is matched with the term of the risk-free security."[27]

By taking a forty-year geometric average of Federal Reserve data on annual nominal returns for 10-year Treasury bills, DOE found for this analysis the following risk-free rates for 2004-2013 (Table 8.2.25).[28] DOE also estimated the ERP by calculating the difference between risk-free rates and stock market return for the same time period.[23]

Table 8.2.25 Risk-Free Rate and Equity Risk Premium, 2004-2013

Year	Risk-free rate (%)	ERP (%)
2004	7.10%	3.25%
2005	7.11%	3.68%
2006	7.10%	3.49%
2007	7.08%	3.36%
2008	7.01%	2.40%
2009	6.88%	3.07%
2010	6.74%	3.23%
2011	6.61%	2.94%
2012	6.41%	3.99%
2013	6.24%	5.30%

The cost of debt financing (k_d) is the interest rate paid on money borrowed by a company. The cost of debt is estimated by adding a risk adjustment factor (R_a) to the risk-free rate. This risk adjustment factor depends on the variability of stock returns represented by standard deviations in stock prices. So for firm *i*, the cost of debt financing is:

$$\boldsymbol{k_{di} = R_f + R_{ai}}$$

Eq. 8.6

Where:

k_d = cost of debt financing for firm, *i*,
R_f = expected return on risk-free assets, and
R_{ai} = risk adjustment factor to risk-free rate for firm, *i*.

DOE estimates the WACC using the following equation:

$$WACC = k_e \times w_e + k_d \times w_d$$

Eq. 8.7

Where:

WACC = weighted average cost of capital,
w_e = proportion of equity financing, and
w_d = proportion of debt financing.

By adjusting for the influence of inflation, DOE estimates the real WACC, or discount rate, for each company. DOE then aggregates the company real WACC to estimate the discount

rate for each of the ownership types in the residential boilers analysis. These values are presented in Table 8.2.26. Table 8.2.26 provides results for average- to large-sized companies. While WACC values for any category may trend higher or lower over substantial periods of time, these values represent a private sector cost of capital that is averaged over major business cycles.

Table 8.2.26 Weighted Average Cost of Capital for Sectors that Purchase Residential Boilers

Sector	Mean Discount Rate (%)	Standard Deviation (%)
Retail	4.30	2.09
Property owners	5.16	1.30
Medical services	4.19	1.86
Industrial	4.95	2.18
Lodging	5.88	2.28
Food Service	4.84	2.60
Offices	5.40	1.85
State/Local Government / Education	2.46	2.15
Federal Government	3.30	1.36
Other	4.35	1.64

Source: Damodaran Online *Data Page: Costs of Capital by Industry Sector,* 2004-2013.

8.2.2.7 Compliance Date of Standard

Pursuant to 42 U.S.C. 6295(m), the compliance date of any new energy efficiency standard for residential boilers is 5 years after the final rule is published. Consistent with its published regulatory agenda, DOE assumed that the final rule would be issued by the end of 2014 and that, therefore, the new standards would require compliance beginning in 2021. DOE calculated the LCC and PBP for all consumers as if they each would purchase a new boiler in 2021.

8.2.2.8 Efficiency Distribution in the No-New-Standards Case

To estimate the market shares of the different efficiency levels in each residential boiler product class beginning in late 2019, DOE developed data on the share of models in each product class that are of the different designs based on ENERY STAR® shipments data, 2003-2012 AHRI shipments data, and the reduced set of residential boiler models (see appendix 7D) (see Table 8.2.27).[11,29] In addition, for gas-fired hot water boilers, DOE accounted for the regional differences in the market shares by efficiency levels. For the standby mode and off mode, the efficiency distribution is based DOE used test data and data provided by Burnham (see Table 8.2.28). For a detailed discussion of the development of no-new-standards case distributions, see appendix 8H.

Table 8.2.27 No-New-Standards Case Market Shares in 2021 by Efficiency Level for Residential Boilers AFUE Standards

EL	Design Option	Fraction of Models
Gas-fired Hot Water Boiler		
0	82% AFUE – Baseline	23%
1	83% AFUE – Increased HX Area	8%
2	84% AFUE – Increased HX Area	11%
3	85% AFUE – Increased HX Area	5%
4	90% AFUE – Condensing Baseline	11%
5	92% AFUE – Increased HX Area	41%
6	96% AFUE – Max Tech	1%
Gas-fired Steam Boiler		
0	80% AFUE – Baseline	17%
1	82% AFUE – Increased HX Area	72%
2	83% AFUE – Max Tech	12%
Oil-fired Hot Water Boiler		
0	84% AFUE – Baseline	44%
1	85% AFUE – Increased HX Area	19%
2	86% AFUE – Increased HX Area	33%
3	91% AFUE – Max Tech	4%
Oil-fired Steam Boiler		
0	82% AFUE – Baseline	45%
1	84% AFUE – Increased HX Area	29%
2	85% AFUE – Increased HX Area	19%
3	86% AFUE – Max Tech	8%

Table 8.2.28 No-New-Standards Case Market Shares in 2021 by Efficiency Level for Residential Boilers Standby Mode and Off Mode Standards

EL	Power (*Watts*)	Fraction of Models (*%*)
Gas-fired Hot Water Boiler		
0	11.5	3%
1	10	3%
2	9.7	3%
3	9	91%
Gas-fired Steam Boiler		
0	10.5	1%
1	9	1%
2	8.7	1%
3	8	97%
Oil-fired Hot Water Boiler		
0	13.5	3%
1	12	3%
2	11.7	3%
3	11	91%
Oil-fired Steam Boiler		
0	13.5	1%
1	12	1%
2	11.7	1%
3	11	97%
Oil-fired Hot Water Boiler		
0	10.5	1%
1	9	1%
2	8.7	1%
3	8	97%
Oil-fired Steam Boiler		
0	10.5	1%
1	9	1%
2	8.7	1%
3	8	97%

8.3 PAYBACK PERIOD INPUTS

The PBP is the amount of time it takes the consumer to recover the assumed higher purchase cost of more-efficient products as a result of lower operating costs. Numerically, the PBP is the ratio of the increase in purchase cost (*i.e.*, from a less efficient design to a more efficient design) to the decrease in first year annual operating expenditures.

The equation for PBP is:

$$PBP = \Delta IC / \Delta OC$$

Eq. 8.8

Where:

PBP = payback period in years,
Δ IC = difference in the total installed cost between the more efficient standard-level product (efficiency levels 1, 2, 3, etc.) and the baseline efficiency product, and
ΔOC = difference in first year annual operating costs.

Payback periods are expressed in years. Payback periods can be greater than the life of the equipment if the increased total installed cost of the more efficient equipment is not recovered fast enough in reduced operating costs.

DOE also calculates a rebuttable PBP, which is the time it takes the consumer to recover the assumed higher purchase cost of more energy-efficient equipment as a result of lower energy costs. Numerically, the rebuttable PBP is the ratio of the increase in purchase cost (*i.e.*, from a less efficient design to a more efficient design) to the decrease in annual energy expenditures; that is, the difference in first year annual energy cost as calculated from the DOE test procedure. The calculation excludes repair costs and maintenance costs.

The data inputs to PBP are the total installed cost of the equipment to the customer for each efficiency level and the annual (first year) operating costs for each efficiency level. The inputs to the total installed cost are the equipment price and the installation cost. The inputs to the operating costs are the annual energy cost, the annual repair cost, and the annual maintenance cost (or, in the case of rebuttable PBP, only the annual energy cost). The PBP uses the same inputs as the LCC analysis, except that electricity price trends are not required. Because the PBP is a "simple" payback, the required electricity cost is only for the year in which a new efficient standard is to take effect—in this case, 2021.

8.4 LIFE-CYCLE COST AND PAYBACK PERIOD RESULTS

DOE's approach for conducting the LCC and PBP analysis relied on developing samples of households that use each of the considered products. DOE also used probability distributions to characterize the uncertainty in many of the inputs to the analysis. DOE used a Monte Carlo simulation technique to perform the LCC and PBP calculations on the households in the sample. LCC and PBP calculations were performed 10,000 times on the sample of households established for each residential product. Each LCC and PBP calculation was performed on a single household that was selected from the sample of the residential users. The selection of a household was based on its sample weight (*i.e.*, how representative a particular household is of other households in the distribution—either regionally or nationally). Each LCC and PBP calculation also sampled from the probability distributions that DOE developed to characterize many of the inputs to the analysis.

DOE calculated PBP relative to the baseline product in each product class. In contrast, DOE calculated LCC savings relative to the base-case product it assigned to the households.

DOE assigned some households a base-case product that is more efficient than some of the standard levels. For that reason, the average LCC impacts are not equal to the difference between the LCC of a specific standard level and the LCC of the baseline product. The calculation of average LCC savings includes households with zero LCC savings (no impact from a standard). DOE considered a household to receive no impact at a given efficiency level if DOE assigned it a base-case product having an efficiency equal to or greater than the efficiency level in question.

National LCC and PBP results are presented below. For results disaggregated by residential and commercial sectors and replacement, and new construction installations, see the Summary worksheet in the LCC spreadsheet tool.

8.4.1 AFUE Results

8.4.1.1 Gas-Fired Hot Water Boilers

Table 8.4.1 and Table 8.4.2 summarize the LCC and PBP results for gas-fired hot water boilers for AFUE standards. In Table 8.4.1, the simple payback is measured relative to the baseline equipment. In Table 8.4.2, the impacts are measured relative to the efficiency distribution in the no-new-standards case in the compliance year (see section 8.2.2.7). Because some consumers purchase products with higher efficiency in the no-new-standards case, the average savings are less than the difference between the average LCC of EL 0 and the average LCC at each EL. The savings refer only to consumers who are affected by a standard at a given EL. Those who already purchase a product with efficiency at or above a given EL are not affected. Consumers for whom the LCC increases at a given EL experience a net cost.

Table 8.4.1 Gas-Fired Hot Water Boilers: LCC and PBP Results (AFUE Standard)

EL	AFUE	Average Costs *2014$*				Simple Payback Period *years*	Average Lifetime *years*
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	82%	$6,371	$1,224	$22,706	$29,077	NA	26.6
1	83%	$6,387	$1,211	$22,468	$28,854	1.2	26.6
2	84%	$6,402	$1,198	$22,235	$28,638	1.2	26.6
3	85%	$6,649	$1,186	$22,024	$28,672	7.5	26.6
4	90%	$7,255	$1,119	$20,761	$28,016	8.4	26.6
5	92%	$7,605	$1,098	$20,392	$27,998	9.9	26.6
6	96%	$8,295	$1,061	$19,700	$27,995	11.8	26.6

Table 8.4.2 Gas-Fired Hot Water Boilers: LCC Savings Relative to the No-New-Standards Case Efficiency Distribution (AFUE Standard)

EL	AFUE	Life-Cycle Cost Savings	
		% of Consumers that Experience Net Cost	Average Savings* *2014$*
0	82%	0.0%	NA
1	83%	0.3%	$210
2	84%	0.4%	$364
3	85%	13.0%	$182
4	90%	21.9%	$632
5	92%	29.2%	$513
6	96%	55.5%	$303

Figure 8.4.1 shows the range of LCC savings for the efficiency levels considered for gas-fired hot water boilers. For each efficiency level, the top and the bottom of the box indicate the 75th and 25th percentiles, respectively. The bar at the middle of the box indicates the median; 50 percent of the households have lifecycle cost savings above this value. The "whiskers" at the bottom and the top of the box indicate the 5th and 95th percentiles. The small box shows the average LCC savings for each efficiency level.

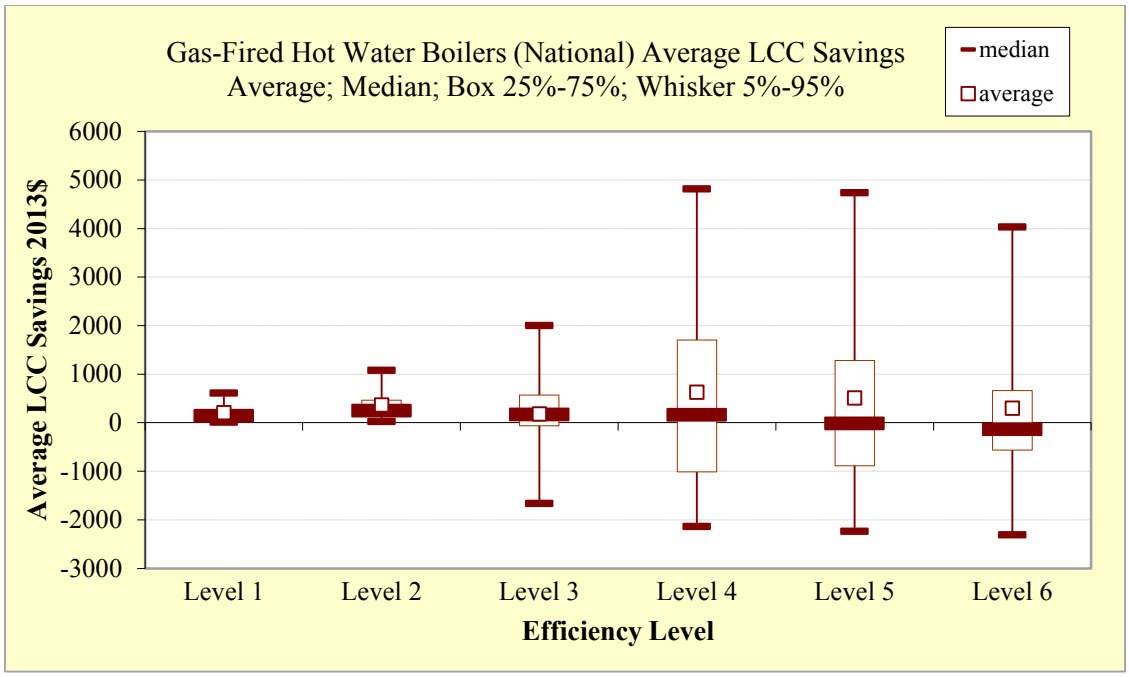

Figure 8.4.1 Distribution of LCC Savings for Gas-Fired Hot Water Boilers (AFUE Standard)

8.4.1.2 Gas-Fired Steam Boilers

Table 8.4.3 and Table 8.4.4 summarize the LCC and PBP results for gas-fired hot water boilers for AFUE standards. In Table 8.4.3, the simple payback is measured relative to the baseline equipment. In Table 8.4.4, the impacts are measured relative to the efficiency distribution in the no-new-standards case in the compliance year (see section 8.2.2.7). Because some consumers purchase products with higher efficiency in the no-new-standards case, the average savings are less than the difference between the average LCC of EL 0 and the average LCC at each EL. The savings refer only to consumers who are affected by a standard at a given EL. Those who already purchase a product with efficiency at or above a given EL are not affected. Consumers for whom the LCC increases at a given EL experience a net cost.

Table 8.4.3 Gas-Fired Steam Boilers: LCC and PBP Results (AFUE Standard)

EL	AFUE	Average Costs *2014$*				Simple Payback Period *years*	Average Lifetime *years*
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	80%	$6,313	$1,087	$18,248	$24,561	NA	23.6
1	82%	$6,376	$1,063	$17,857	$24,234	2.7	23.6
2	83%	$6,682	$1,052	$17,672	$24,355	10.7	23.6

Table 8.4.4 Gas-Fired Steam Boilers: LCC Savings Relative to the No-New-Standards Case Efficiency Distribution (AFUE Standard)

EL	AFUE	Life-Cycle Cost Savings	
		% of Consumers that Experience Net Cost	Average Savings* *2014$*
0	80%	0.0%	NA
1	82%	0.9%	$333
2	83%	30.8%	$207

Figure 8.4.2 shows the range of LCC savings for the efficiency levels considered for gas-fired steam boilers. For each efficiency level, the top and the bottom of the box indicate the 75th and 25th percentiles, respectively. The bar at the middle of the box indicates the median; 50 percent of the households have life-cycle cost savings above this value. The "whiskers" at the bottom and the top of the box indicate the 5th and 95th percentiles. The small box shows the average LCC savings for each efficiency level.

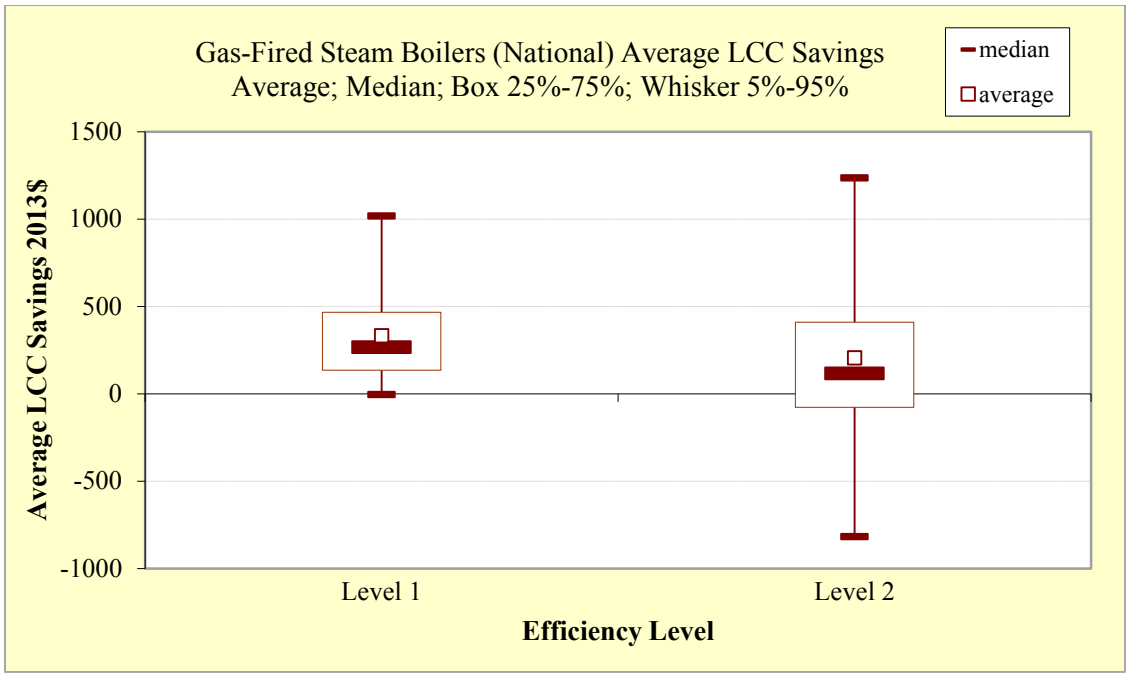

Figure 8.4.2 Distribution of LCC Savings for Gas-Fired Steam Boilers (AFUE Standard)

8.4.1.3 Oil-Fired Hot Water Boilers

Table 8.4.5 and Table 8.4.6 summarize the LCC and PBP results for gas-fired hot water boilers for AFUE standards. In Table 8.4.5, the simple payback is measured relative to the baseline equipment. In Table 8.4.6, the impacts are measured relative to the efficiency distribution in the no-new-standards case in the compliance year (see section 8.2.2.7). Because

some consumers purchase products with higher efficiency in the no-new-standards case, the average savings are less than the difference between the average LCC of EL 0 and the average LCC at each EL. The savings refer only to consumers who are affected by a standard at a given EL. Those who already purchase a product with efficiency at or above a given EL are not affected. Consumers for whom the LCC increases at a given EL experience a net cost.

Table 8.4.5 Oil-Fired Hot Water Boilers: LCC and PBP Results (AFUE Standard)

EL	AFUE	Average Costs *2014$*				Simple Payback Period *years*	Average Lifetime *years*
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	84%	$8,049	$2,021	$38,982	$47,031	NA	24.7
1	85%	$8,200	$1,999	$38,553	$46,753	6.9	24.7
2	86%	$8,351	$1,969	$37,962	$46,313	5.8	24.7
3	91%	$10,691	$1,861	$35,842	$46,534	16.5	24.7

Table 8.4.6 Oil-Fired Hot Water Boilers: LCC Savings Relative to the No-New-Standards Case Efficiency Distribution (AFUE Standard)

EL	AFUE	Life-Cycle Cost Savings	
		% of Consumers that Experience Net Cost	Average Savings* *2014$*
0	84%	0.0%	NA
1	85%	10.4%	$260
2	86%	8.8%	$626
3	91%	58.9%	$192

Figure 8.4.3 shows the range of LCC savings for the efficiency levels considered for oil-fired hot water boilers. For each efficiency level, the top and the bottom of the box indicate the 75th and 25th percentiles, respectively. The bar at the middle of the box indicates the median; 50 percent of the households have life-cycle cost savings above this value. The "whiskers" at the bottom and the top of the box indicate the 5th and 95th percentiles. The small box shows the average LCC savings for each efficiency level.

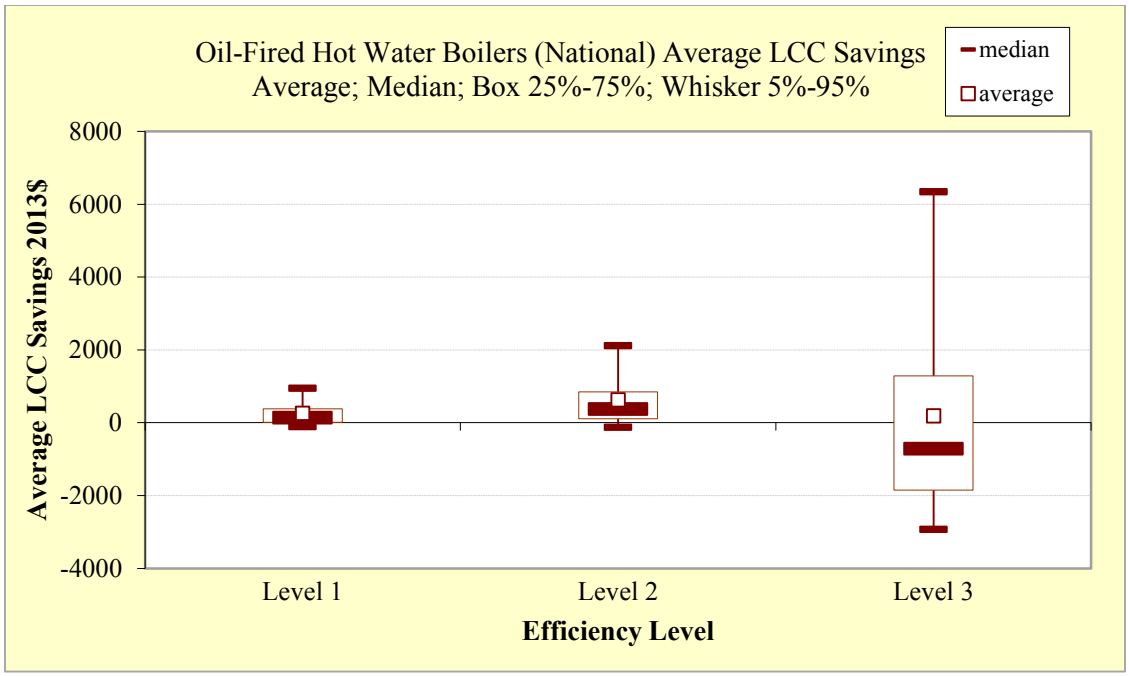

Figure 8.4.3 Distribution of LCC Savings for Oil-Fired Hot Water Boilers (AFUE Standard)

8.4.1.4 Oil-Fired Steam Boilers

Table 8.4.7 Table 8.4.7and Table 8.4.8 summarize the LCC and PBP results for gas-fired hot water boilers for AFUE standards. In Table 8.4.7, the simple payback is measured relative to the baseline equipment. In Table 8.4.8, the impacts are measured relative to the efficiency distribution in the no-new-standards case in the compliance year (see section 8.2.2.7). Because some consumers purchase products with higher efficiency in the no-new-standards case, the average savings are less than the difference between the average LCC of EL 0 and the average LCC at each EL. The savings refer only to consumers who are affected by a standard at a given EL. Those who already purchase a product with efficiency at or above a given EL are not affected. Consumers for whom the LCC increases at a given EL experience a net cost.

Table 8.4.7 Oil-Fired Steam Boilers: LCC and PBP Results (AFUE Standard)

EL	AFUE	Average Costs *2014$*				Simple Payback Period *years*	Average Lifetime *years*
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	82%	$7,886	$1,973	$30,263	$38,149	NA	19.3
1	84%	$8,189	$1,928	$29,558	$37,747	6.6	19.3
2	85%	$8,341	$1,906	$29,219	$37,560	6.7	19.3
3	86%	$8,644	$1,876	$28,760	$37,404	7.8	19.3

Table 8.4.8 Oil-Fired Steam Boilers: LCC Savings Relative to the No-New-Standards Case Efficiency Distribution (AFUE Standard)

EL	AFUE	Life-Cycle Cost Savings	
		% of Consumers that Experience Net Cost	Average Savings* *2014$*
0	82%	0.0%	NA
1	84%	11.9%	$400
2	85%	19.7%	$434
3	86%	34.2%	$505

Figure 8.4.4 show the range of LCC savings for the efficiency levels considered for oil-fired steam boilers. For each efficiency level, the top and the bottom of the box indicate the 75th and 25th percentiles, respectively. The bar at the middle of the box indicates the median; 50 percent of the households have life-cycle cost savings above this value. The "whiskers" at the bottom and the top of the box indicate the 5th and 95th percentiles. The small box shows the average LCC savings for each efficiency level.

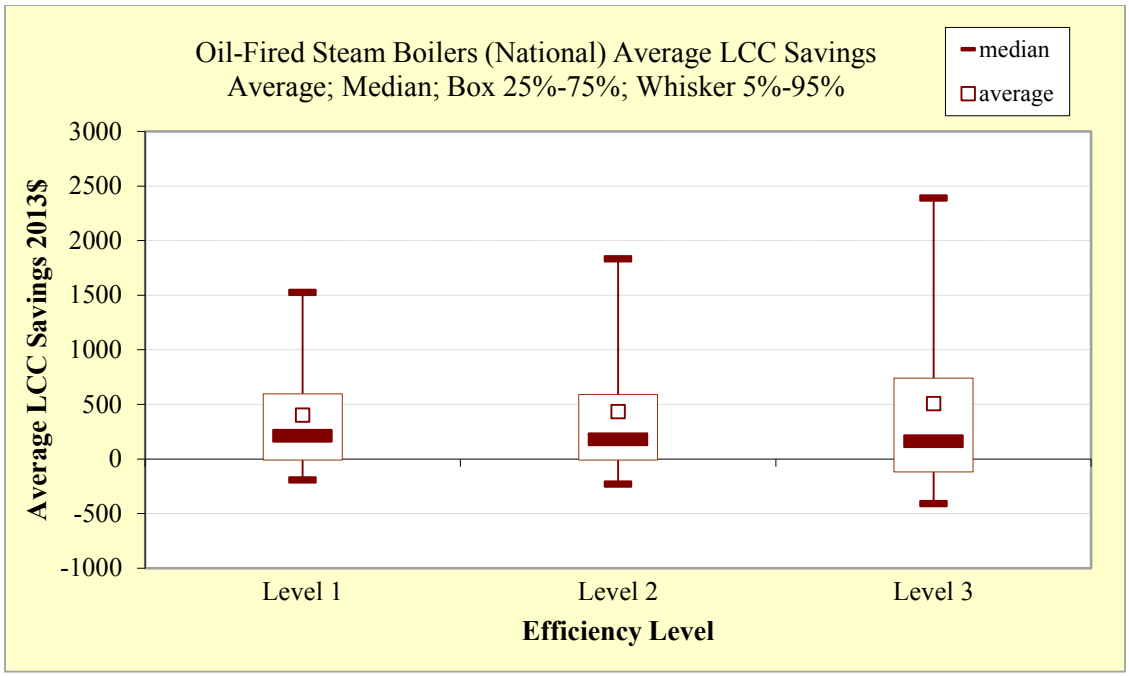

Figure 8.4.4 Distribution of LCC Savings for Oil-Fired Steam Boilers (AFUE Standard)

8.4.2 Standby Mode and Off Mode Results

8.4.2.1 Gas-Fired Hot Water Boilers

Table 8.4.9 and Table 8.4.10 summarize the LCC and PBP results for gas-fired hot water boilers for standby mode and off mode standards. In Table 8.4.9, the simple payback is measured relative to the baseline equipment. In Table 8.4.10, the impacts are measured relative to the efficiency distribution in the no-new-standards case in the compliance year (see section 8.2.2.7). Because some consumers purchase products with higher efficiency in the no-new-standards case, the average savings are less than the difference between the average LCC of EL 0 and the average LCC at each EL. The savings refer only to consumers who are affected by a standard at a given EL. Those who already purchase a product with efficiency at or above a given EL are not affected. Consumers for whom the LCC increases at a given EL experience a net cost.

Table 8.4.9 Gas-Fired Hot Water Boilers: LCC and PBP Results (Standby Mode and Off Mode)

EL	Average Costs *2014$*				Simple Payback Period *years*	Average Lifetime *years*
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	$28	$14	$260	$288	NA	26.6
1	$32	$12	$225	$257	2.0	26.6
2	$49	$12	$218	$267	8.9	26.6
3	$50	$11	$202	$251	6.7	26.6

Table 8.4.10 Gas-Fired Hot Water Boilers: LCC Savings Relative to the No-New-Standards Case Efficiency Distribution (Standby Mode and Off Mode)

EL	Life-Cycle Cost Savings	
	% of Consumers that Experience Net Cost	Average Savings* *2014$*
0	0.0%	NA
1	0.0%	$26
2	3.7%	$2
3	1.8%	$15

Figure 8.4.5 show the range of LCC savings for the standby mode and off mode efficiency levels considered for gas-fired hot water boilers. For each efficiency level, the top and the bottom of the box indicate the 75th and 25th percentiles, respectively. The bar at the middle of the box indicates the median; 50 percent of the households have life-cycle cost savings above this value. The "whiskers" at the bottom and the top of the box indicate the 5th and 95th percentiles. The small box shows the average LCC savings for each efficiency level.

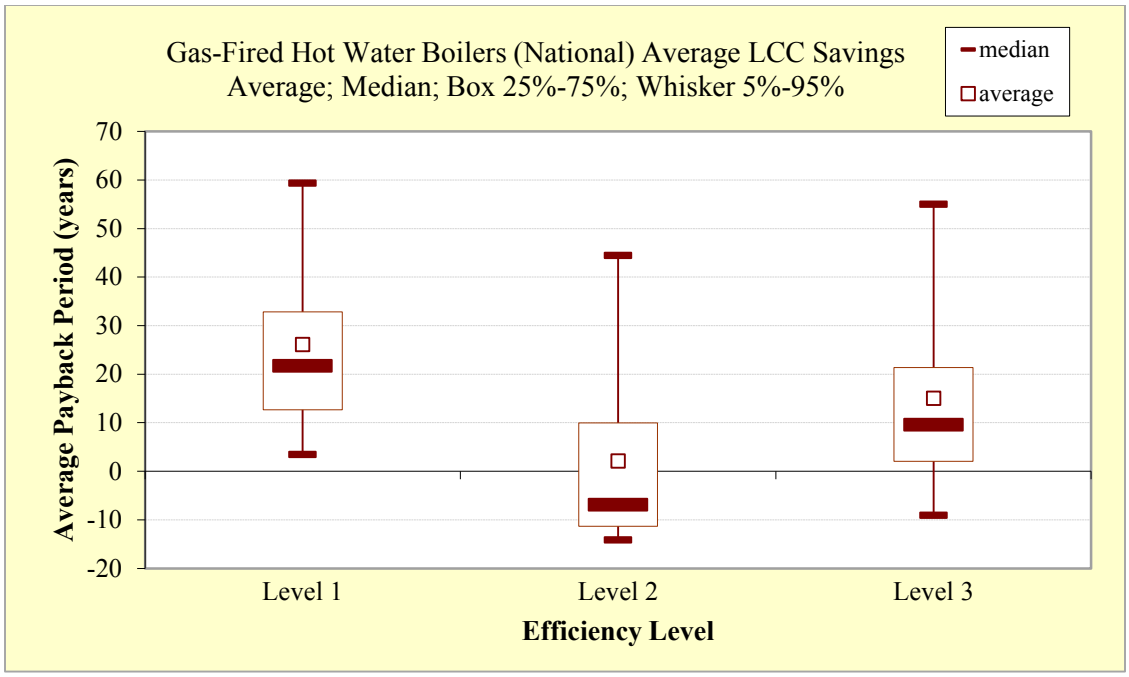

Figure 8.4.5 Distribution of LCC Savings for Gas-Fired Hot Water Boilers (Standby Mode and Off Mode)

8.4.2.2 Gas-Fired Steam Boilers

Table 8.4.11 and Table 8.4.12 summarize the LCC and PBP results for gas-fired hot water boilers for standby mode and off mode standards. In Table 8.4.11, the simple payback is measured relative to the baseline equipment. In Table 8.4.12, the impacts are measured relative to the efficiency distribution in the no-new-standards case in the compliance year (see section 8.2.2.7). Because some consumers purchase products with higher efficiency in the no-new-standards case, the average savings are less than the difference between the average LCC of EL 0 and the average LCC at each EL. The savings refer only to consumers who are affected by a standard at a given EL. Those who already purchase a product with efficiency at or above a given EL are not affected. Consumers for whom the LCC increases at a given EL experience a net cost.

Table 8.4.11 Gas-Fired Steam Boilers: LCC and PBP Results (Standby Mode and Off Mode)

EL	Average Costs *2014$*				Simple Payback Period *years*	Average Lifetime *years*
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	$28	$14	$227	$255	NA	23.6
1	$31	$12	$194	$226	1.9	23.6
2	$48	$11	$188	$236	8.5	23.6
3	$49	$10	$172	$221	6.4	23.6

Table 8.4.12 Gas-Fired Steam Boilers: LCC Savings Relative to the No-New-Standards Case Efficiency Distribution (Standby Mode and Off Mode)

EL	Life-Cycle Cost Savings	
	% of Consumers that Experience Net Cost	Average Savings* *2014$*
0	0.0%	NA
1	0.0%	$31
2	1.3%	$4
3	0.5%	$18

Figure 8.4.6 shows the range of LCC savings for the standby mode and off mode efficiency levels considered for gas-fired steam boilers. For each efficiency level, the top and the bottom of the box indicate the 75th and 25th percentiles, respectively. The bar at the middle of the box indicates the median; 50 percent of the households have life-cycle cost savings above this value. The "whiskers" at the bottom and the top of the box indicate the 5th and 95th percentiles. The small box shows the average LCC savings for each efficiency level.

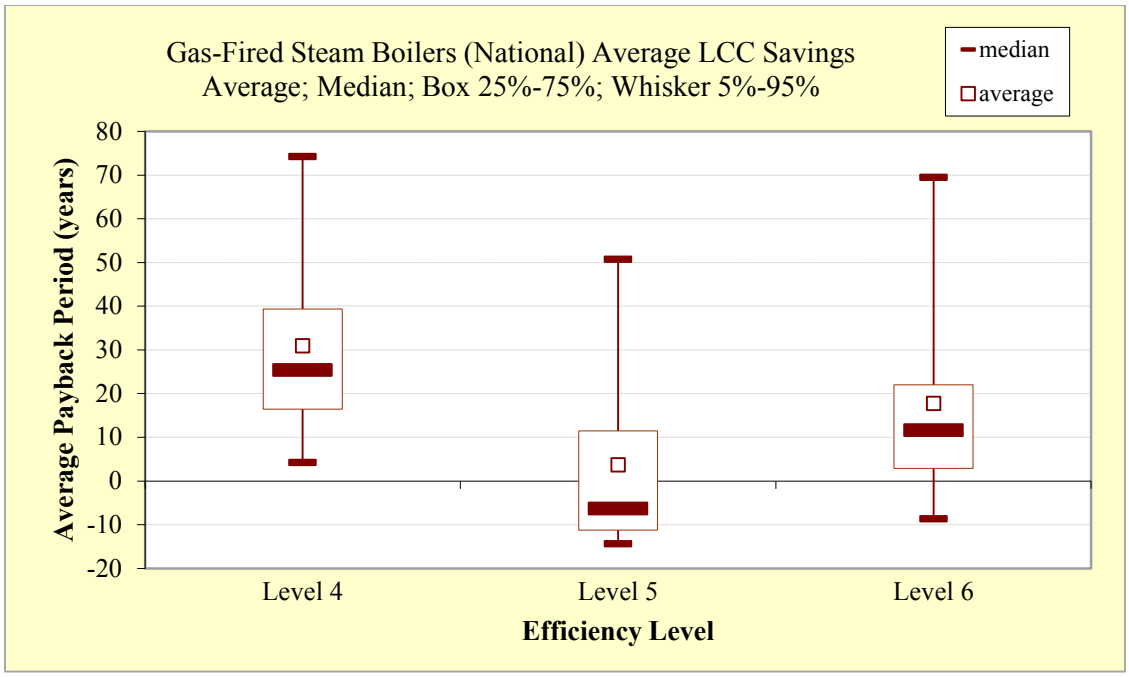

Figure 8.4.6 Distribution of LCC Savings for Gas-Fired Steam Boilers (Standby Mode and Off Mode)

8.4.2.3 Oil-Fired Hot Water Boilers

Table 8.4.13 and Table 8.4.14 summarize the LCC and PBP results for gas-fired hot water boilers for standby mode and off mode standards. In Table 8.4.13, the simple payback is measured relative to the baseline equipment. In Table 8.4.14, the impacts are measured relative to the efficiency distribution in the no-new-standards case in the compliance year (see section 8.2.2.7). Because some consumers purchase products with higher efficiency in the no-new-standards case, the average savings are less than the difference between the average LCC of EL 0 and the average LCC at each EL. The savings refer only to consumers who are affected by a standard at a given EL. Those who already purchase a product with efficiency at or above a given EL are not affected. Consumers for whom the LCC increases at a given EL experience a net cost.

Table 8.4.13 Oil-Fired Hot Water Boilers: Summary LCC and PBP Results (Standby Mode and Off Mode)

EL	Average Costs *2014$*				Simple Payback Period *years*	Average Lifetime *years*
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	$28	$18	$317	$344	NA	24.7
1	$31	$16	$281	$313	1.8	24.7
2	$48	$16	$274	$322	8.2	24.7
3	$49	$15	$258	$307	6.2	24.7

Table 8.4.14 Oil-Fired Hot Water Boilers: LCC and PBP Results (Standby Mode and Off Mode)

EL	Life-Cycle Cost Savings	
	% of Consumers that Experience Net Cost	Average Savings* *2014$*
0	0.0%	NA
1	0.0%	$32
2	3.5%	$6
3	1.4%	$20

Figure 8.4.7 shows the range of LCC savings for the standby mode and off mode efficiency levels considered for oil-fired hot water boilers. For each efficiency level, the top and the bottom of the box indicate the 75th and 25th percentiles, respectively. The bar at the middle of the box indicates the median; 50 percent of the households have life-cycle cost savings above this value. The "whiskers" at the bottom and the top of the box indicate the 5th and 95th percentiles. The small box shows the average LCC savings for each efficiency level.

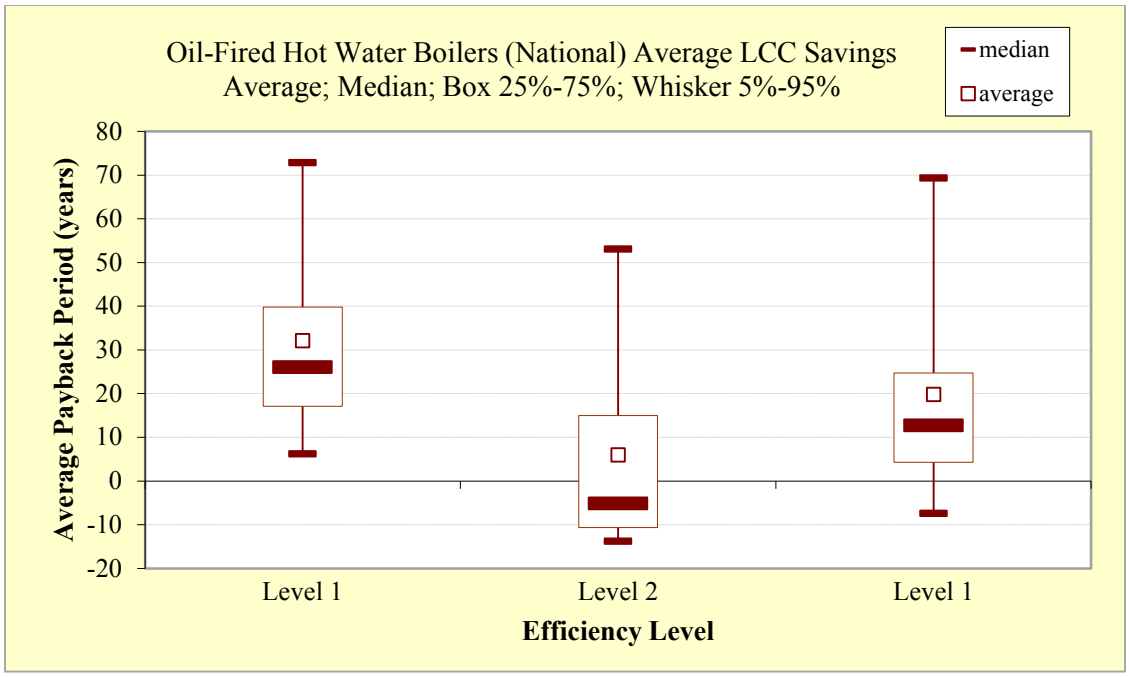

Figure 8.4.7 Distribution of LCC Savings for Oil-Fired Hot Water Boilers (Standby Mode and Off Mode)

8.4.2.4 Oil-Fired Steam Boilers

Table 8.4.15 and Table 8.4.16 summarize the LCC and PBP results for gas-fired hot water boilers for standby mode and off mode standards. In Table 8.4.15, the simple payback is measured relative to the baseline equipment. In Table 8.4.16, the impacts are measured relative to the efficiency distribution in the no-new-standards case in the compliance year (see section 8.2.2.7). Because some consumers purchase products with higher efficiency in the no-new-standards case, the average savings are less than the difference between the average LCC of EL 0 and the average LCC at each EL. The savings refer only to consumers who are affected by a standard at a given EL. Those who already purchase a product with efficiency at or above a given EL are not affected. Consumers for whom the LCC increases at a given EL experience a net cost.

Table 8.4.15 Oil-Fired Steam Boilers: LCC and PBP Results (Standby Mode and Off Mode)

EL	Average Costs *2014$*				Simple Payback Period *years*	Average Lifetime *years*
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	$28	$19	$266	$294	NA	19.3
1	$31	$17	$236	$268	1.8	19.3
2	$48	$16	$230	$278	8.0	19.3
3	$49	$15	$216	$265	6.1	19.3

Table 8.4.16 Oil-Fired Steam Boilers: Mode LCC Savings Relative to the No-New-Standards Case Efficiency Distribution (Standby Mode and Off Mode)

EL	Life-Cycle Cost Savings	
	% of Consumers that Experience Net Cost	Average Savings* *2014$*
0	0.0%	NA
1	0.0%	$26
2	1.3%	$0.4
3	0.6%	$13

Figure 8.4.8 show the range of LCC savings for the standby mode and off mode efficiency levels considered for oil-fired steam boilers. For each efficiency level, the top and the bottom of the box indicate the 75th and 25th percentiles, respectively. The bar at the middle of the box indicates the median; 50 percent of the households have life-cycle cost savings above this value. The "whiskers" at the bottom and the top of the box indicate the 5th and 95th percentiles. The small box shows the average LCC savings for each efficiency level.

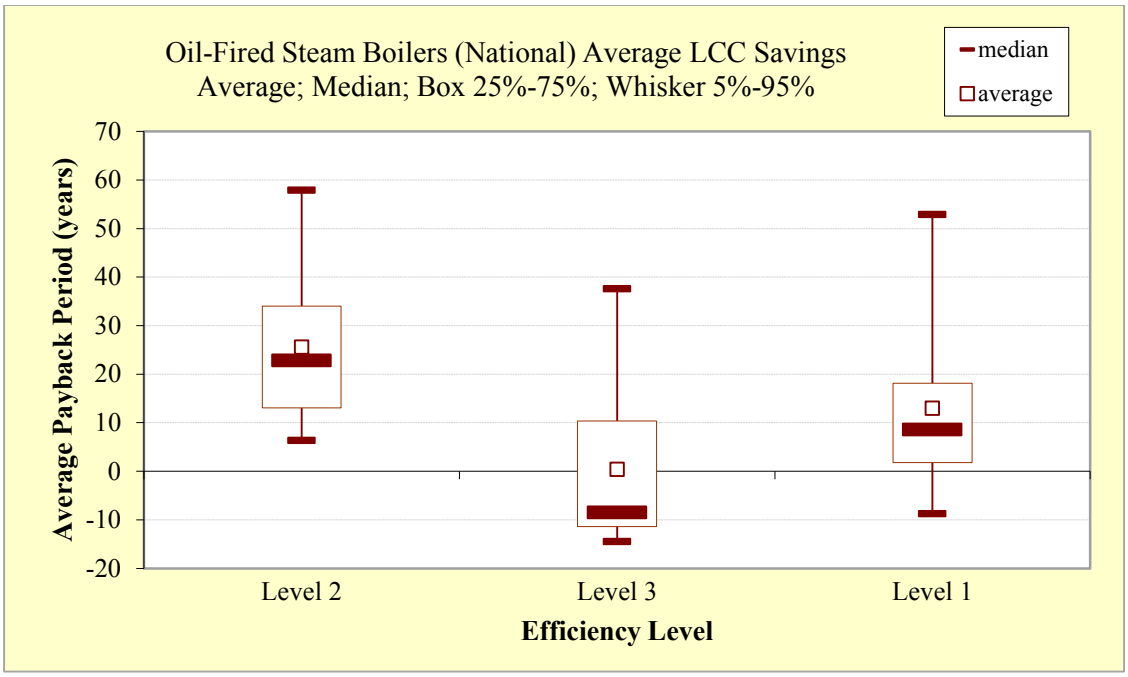

Figure 8.4.8 Distribution of LCC Savings for Oil-Fired Steam Boilers (Standby Mode and Off Mode)

8.4.2.5 Electric Hot Water Boilers

Table 8.4.17 and Table 8.4.18 summarize the LCC and PBP results for gas-fired hot water boilers for standby mode and off mode standards. In Table 8.4.17, the simple payback is measured relative to the baseline equipment. In Table 8.4.18, the impacts are measured relative to the efficiency distribution in the no-new-standards case in the compliance year (see section 8.2.2.7). Because some consumers purchase products with higher efficiency in the no-new-standards case, the average savings are less than the difference between the average LCC of EL 0 and the average LCC at each EL. The savings refer only to consumers who are affected by a standard at a given EL. Those who already purchase a product with efficiency at or above a given EL are not affected. Consumers for whom the LCC increases at a given EL experience a net cost.

Table 8.4.17 Electric Hot Water Boilers: LCC and PBP Results (Standby Mode and Off Mode)

EL	Average Costs *2014$*				Simple Payback Period *years*	Average Lifetime *years*
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	$27	$10	$170	$197	NA	26.6
1	$31	$8	$145	$176	2.6	26.6
2	$47	$8	$141	$188	11.7	26.6
3	$48	$7	$129	$177	8.9	26.6

Table 8.4.18 Electric Hot Water Boilers: LCC Savings Relative to the No-New-Standards Case Efficiency Distribution (Standby Mode and Off Mode)

EL	Life-Cycle Cost Savings	
	% of Consumers that Experience Net Cost	Average Savings* *2014$*
0	0.0%	NA
1	0.0%	$19
2	1.5%	-$3
3	1.0%	$8

Figure 8.4.9 show the range of LCC savings for the standby mode and off mode efficiency levels considered for electric hot water boilers. For each efficiency level, the top and the bottom of the box indicate the 75th and 25th percentiles, respectively. The bar at the middle of the box indicates the median; 50 percent of the households have life-cycle cost savings above this value. The "whiskers" at the bottom and the top of the box indicate the 5th and 95th percentiles. The small box shows the average LCC savings for each efficiency level.

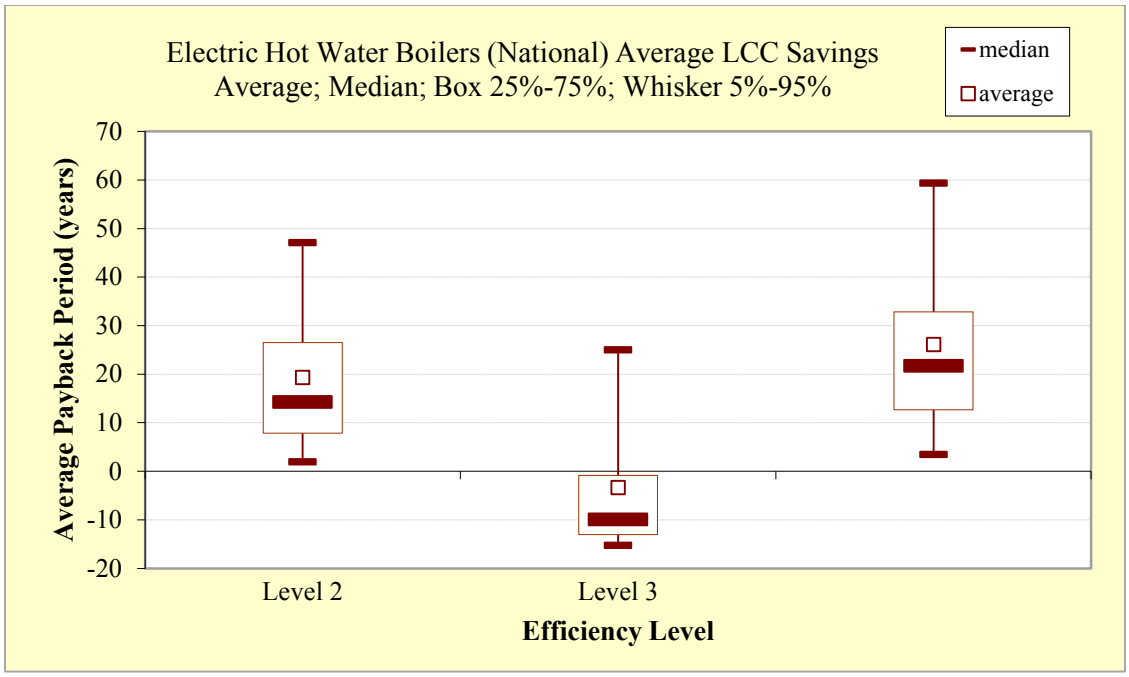

Figure 8.4.9 Distribution of LCC Savings for Electric Hot Water Boilers (Standby Mode and Off Mode)

8.4.2.6 Electric Steam Boilers

Table 8.4.19 and Table 8.4.20 summarize the LCC and PBP results for gas-fired hot water boilers for standby mode and off mode standards. In Table 8.4.19, the simple payback is measured relative to the baseline equipment. In Table 8.4.20, the impacts are measured relative to the efficiency distribution in the no-new-standards case in the compliance year (see section 8.2.2.7). Because some consumers purchase products with higher efficiency in the no-new-standards case, the average savings are less than the difference between the average LCC of EL 0 and the average LCC at each EL. The savings refer only to consumers who are affected by a standard at a given EL. Those who already purchase a product with efficiency at or above a given EL are not affected. Consumers for whom the LCC increases at a given EL experience a net cost.

Table 8.4.19 Electric Steam Boilers: LCC and PBP Results (Standby Mode and Off Mode)

EL	Average Costs *2014$*				Simple Payback Period *years*	Average Lifetime *years*
	Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
0	$27	$10	$155	$182	NA	23.6
1	$31	$9	$133	$164	2.6	23.6
2	$47	$8	$129	$176	11.7	23.6
3	$48	$8	$118	$166	8.8	23.6

Table 8.4.20 Electric Steam Boilers: LCC Savings Relative to the No-New-Standards Case Efficiency Distribution (Standby Mode and Off Mode)

EL	Life-Cycle Cost Savings	
	% of Consumers that Experience Net Cost	Average Savings* *2014$*
0	0.0%	NA
1	0.0%	$17
2	1.5%	-$5
3	1.0%	$6

Figure 8.4.10 show the range of LCC savings for the standby mode and off mode efficiency levels considered for electric steam boilers. For each efficiency level, the top and the bottom of the box indicate the 75th and 25th percentiles, respectively. The bar at the middle of the box indicates the median; 50 percent of the households have life-cycle cost savings above this value. The "whiskers" at the bottom and the top of the box indicate the 5th and 95th percentiles. The small box shows the average LCC savings for each efficiency level.

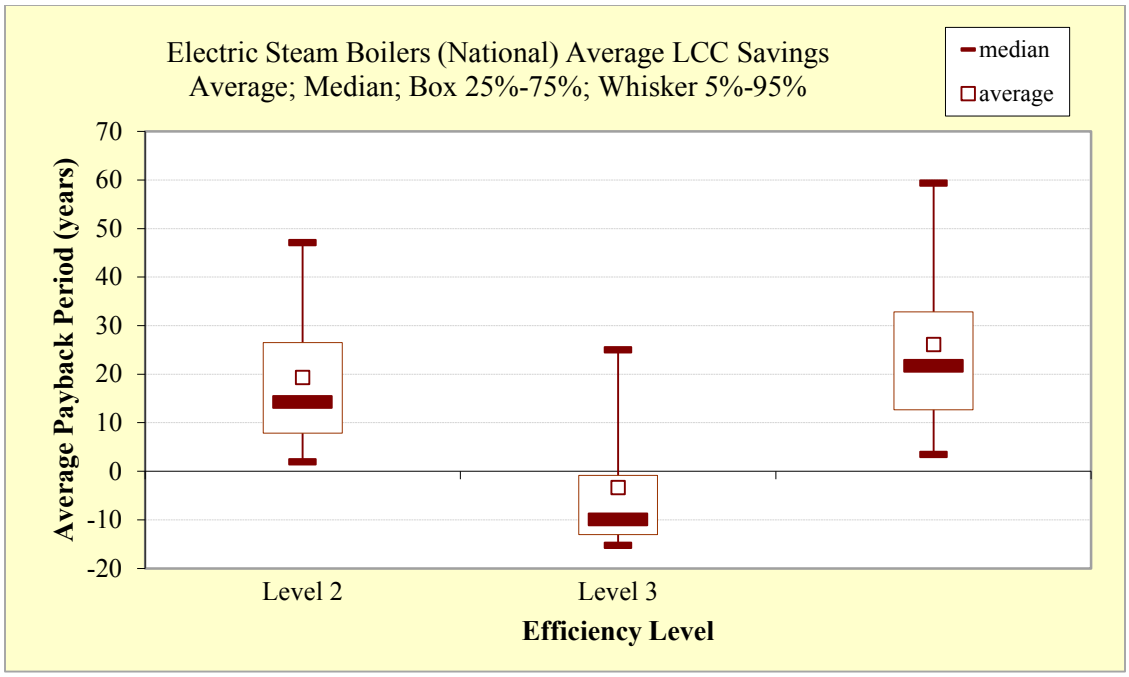

Figure 8.4.10 Distribution of LCC Savings for Electric Steam Boilers (Standby Mode and Off Mode)

8.5 REBUTTABLE PAYBACK PERIOD

DOE presents rebuttable PBPs to provide the legally established rebuttable presumption that an energy efficiency standard is economically justified if the additional product costs attributed to the standard are less than three times the value of the first-year energy cost savings. (42 U.S.C. §6295 (o)(2)(B)(iii))

The basic equation for rebuttable PBP is the same as that shown for the BP in section 8.1.1. Unlike the analyses described in section 8.2, however, the rebuttable PBP is not based on the use of household samples and probability distributions, and it is based not on distributions but on discrete single-point values. For example, whereas DOE uses a probability distribution of energy prices in the distributional PBP analysis, it uses only the national average energy price to determine the rebuttable PBP.

8.5.1 Inputs

Inputs for the rebuttable PBP differ from the distribution PBP in that the calculation uses discrete values, rather than distributions. Note that for the calculation of distribution PBP, because inputs for the determination of total installed cost were based on single-point values, only the variability and/or uncertainty in the inputs for determining operating cost contributed to variability in the distribution PBPs. The following summarizes the single-point values that DOE used in determining the rebuttable PBP:

- Manufacturing costs, markups, sales taxes, and installation costs were all based on the single-point values used in the distributional LCC and PBP analysis.
- Energy prices were based on national average values for the year that new standards will take effect.
- An average discount rate or lifetime is not required in the rebuttable PBP calculation.
- The effective date of the standard is assumed to be 2021.

8.5.2 Results

DOE calculated rebuttable PBPs for each efficiency level relative to the distribution of product energy efficiencies estimated for the no-new-standards case. Table 8.5.1 through Table 8.5.4 present the rebuttable PBPs for residential boilers for AFUE standards. Table 8.5.5 through Table 8.5.10 present the rebuttable PBPs for standby mode and off mode standards.

Table 8.5.1 Rebuttable Payback Period for Gas-Fired Hot Water Boilers (AFUE Standard)

EL	Technology Option	Rebuttable Payback Period *years*
1	83% AFUE - Increased HX Area	1.6
2	84% AFUE - Increased HX Area	1.7
3	85% AFUE - Increased HX Area	9.1
4	90% AFUE - Condensing Baseline	11.3
5	92% AFUE - Increased HX Area	13.1
6	96% AFUE - Max Tech	15.5

Table 8.5.2 Rebuttable Payback Period for Gas-Fired Steam Boilers (AFUE Standard)

EL	Technology Option	Rebuttable Payback Period *years*
1	82% AFUE - Increased HX Area	2.7
2	83% AFUE - Max Tech	11.5

Table 8.5.3 Rebuttable Payback Period for Oil-Fired Hot Water Boilers (AFUE Standard)

EL	Technology Option	Rebuttable Payback Period *years*
1	85% AFUE - Increased HX Area	7.9
2	86% AFUE - Increased HX Area	7.0
3	91% AFUE - Condensing (Max Tech)	16.7

Table 8.5.4 Rebuttable Payback Period for Oil-Fired Steam Boilers (AFUE Standard)

EL	Technology Option	Rebuttable Payback Period *years*
1	84% AFUE - Increased HX Area	6.0
2	85% AFUE - Increased HX Area	6.7
3	86% AFUE - Max Tech	8.3

Table 8.5.5 Rebuttable Payback Period for Gas-Fired Hot Water Boilers (Standby Mode and Off Mode)

Efficiency Level	Technology Option	Rebuttable Payback Period *years*
1	Linear PS, Toroidal Xfmr	3.5
2	Switch Mode PS	15.7
3	SMPS, Toroidal Xfmr	11.9

Table 8.5.6 Rebuttable Payback Period for Gas-Fired Steam Boilers (Standby Mode and Off Mode)

Efficiency Level	Technology Option	Rebuttable Payback Period *years*
1	Linear PS, Toroidal Xfmr	3.5
2	Switch Mode PS	15.7
3	SMPS, Toroidal Xfmr	11.9

Table 8.5.7 Rebuttable Payback Period for Oil-Fired Hot Water Boilers (Standby Mode and Off Mode)

Efficiency Level	Technology Option	Rebuttable Payback Period *years*
1	Linear PS, Toroidal Xfmr	3.4
2	Switch Mode PS	15.4
3	SMPS, Toroidal Xfmr	11.7

Table 8.5.8 Rebuttable Payback Period for Oil-Fired Steam Boilers (Standby Mode and Off Mode)

Efficiency Level	Technology Option	Rebuttable Payback Period *years*
1	Linear PS, Toroidal Xfmr	3.5
2	Switch Mode PS	15.5
3	SMPS, Toroidal Xfmr	11.7

Table 8.5.9 Rebuttable Payback Period for Electric Hot Water Boilers (Standby Mode and Off Mode)

Efficiency Level	Technology Option	Rebuttable Payback Period *years*
1	Linear PS, Toroidal Xfmr	3.0
2	Switch Mode PS	13.6
3	SMPS, Toroidal Xfmr	10.3

Table 8.5.10 Rebuttable Payback Period for Electric Steam Boilers (Standby Mode and Off Mode)

Efficiency Level	Technology Option	Rebuttable Payback Period *years*
1	Linear PS, Toroidal Xfmr	2.7
2	Switch Mode PS	13.5
3	SMPS, Toroidal Xfmr	10.2

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APPENDIX 8A. USER INSTRUCTIONS FOR THE LIFE-CYCLE COST ANALYSIS SPREADSHEET FOR RESIDENTIAL BOILERS

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APPENDIX 8A. USER INSTRUCTIONS FOR THE LIFE-CYCLE COST ANALYSIS SPREADSHEET FOR RESIDENTIAL BOILERS

8A.1 USER INSTRUCTIONS

The results obtained in this analysis can be examined and reproduced using the Microsoft Excel spreadsheets available on the Department of Energy's (DOE's) residential boiler rulemaking website: https://www1.eere.energy.gov/buildings/appliance_standards/rulemaking.aspx?ruleid=112. From that page, follow the links to the notice of proposed rulemaking phase and then to Analytical Tools.

8A.2 STARTUP

DOE's spreadsheets enables users to perform life-cycle cost (LCC) and payback period (PBP) analyses for each product class. Two spreadsheets exist for all six residential boiler product classes: a spreadsheet labeled LCC and another labeled analysis input. The analysis input contains the raw data used for the analysis as well the formulas that led to the processed data that are used in the LCC. The analysis input serves the purpose of delivering the raw input used in the analysis as well as of informing the public on how the processed data in the main LCC is derived, for complete transparency.

The two spreadsheets are independent. The main LCC spreadsheet can be downloaded and run separately. To change the input of the main LCC based on updated data from the analysis input, the user will need to manually copy/paste the data that was modified in the analysis input into the main LCC spreadsheet.

To examine the spreadsheets, DOE assumes that the user has access to a personal computer with a hardware configuration capable of running Windows XP or later. All LCC spreadsheets require Microsoft Excel 2003 or later installed under the Windows operating system. Because certain variables inside the spreadsheets are defined as distributions, a copy of Crystal Ball[a] (a commercially available add-on program) is required to view them.

8A.3 DESCRIPTION OF LIFE-CYCLE COST WORKSHEETS

8A.3.1 LCC Worksheet

For all of the residential boiler product classes, DOE created a single LCC spreadsheet containing a collection of worksheets. Each worksheet represents a conceptual component within the LCC calculation. To facilitate navigability and identify how worksheets are related, each worksheet contains an area on the extreme left showing variables imported to and exported from the current worksheet. The LCC spreadsheet contains the following worksheets:

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[a] See www.oracle.com/us/products/applications/crystalball/overview/index.html

Introduction	The *Introduction* worksheet contains an overview of each worksheet and a flow chart of the inputs and outputs of the spreadsheet,
Statistics	The *Statistics* worksheet contains the statistics of key parameters from the outcome of the Monte Carlo simulations for the sample of households
Summary	The *Summary* worksheet contains a user interface to manipulate energy price trends and start year inputs, and to run the Crystal Ball simulation. LCC and PBP simulation results for each efficiency level are also displayed here.
LCC&PB Calcs*	The *LCC&PB Calcs* worksheet shows LCC calculation results for different efficiency levels for a single Residential Energy Consumption Survey (RECS) 2009 household[1] or Commercial Building Energy Consumption Survey (CBECS) 2003 building.[2] During a Crystal Ball simulation, the spreadsheet records the LCC and PBP values for every sampled household.
LCC&PB by Category*	The *LCC&PB Calcs* worksheet shows LCC calculation results from LCC&PB Calcs disaggregated by different markets (residential replacement, residential new construction, commercial replacement, and commercial new construction).
Rebuttable PBP	The *Rebuttable PBP* worksheet contains the total and incremental manufacturer costs, retail prices, installation costs, repair and maintenance costs, energy use calculations, and the simple PBP calculations for each efficiency level. DOE's residential furnace and boiler test procedure is used to calculate parameters used in energy use calculations.
Product Price*	The *Product Price* worksheet calculates retail price values used as inputs in the LCC calculations in the *Summary* worksheet.
Markups*	The *Markups* worksheet calculates markup values used as inputs in the *Equip Price* worksheet. DOE applied baseline and incremental markups to calculate final retail prices. DOE calculated the markups differently for replacement units and new units.
Product Price Trend	The *Product Price Trend* worksheet calculates projected product price trend scenarios used to adjust the manufacturer's cost over the entire analysis period as inputs in the *Product Price* worksheet.
Installation Cost*	The *Installation Cost* worksheet provides the weighted average installation cost for each design option. These results are used to calculate the total installed prices of the design options.
Installation Cost Data	The *Installation Cost Data* worksheet provides the data inputs to the installation cost calculations.
Maintenance and Repair Cost*	The *Maintenance and Repair Cost* worksheet provides the maintenance and repair costs for each design option. These results are used to determine operating costs for the design options.

Labor Costs*	The *Labor Cost* worksheet provides the labor cost by region as used to determine the installation and repair/maintenance costs.
Building Sample*	The *Building Sample* worksheet contains the RECS 2009 and CBECS 2003 household data for each product class. During a Crystal Ball simulation, DOE uses these household characteristics to determine the analysis parameters.
Base Case AFUE*	The *Base Case Efficiency* worksheet includes the boiler efficiency distribution for 2020.
AFUE (Existing)*	The *Existing AFUE (existing)* worksheet includes the boiler efficiency for all years during the period 1978-2009.
Energy Use*	The *Energy Use* worksheet calculates annual energy use by fuel type, depending on product class. The annual energy use calculations for each design option are inputs to the *LCC&PB Calcs* worksheet to calculate the annual operating cost of the LCC.
Energy Use (Calcs)*	The *Energy Use (Calcs)* worksheet displays intermediate energy use calculations. The intermediate energy use calculations for each design option are inputs to the *Energy Use* worksheet to calculate the annual energy use by fuel type, depending on product class.
Energy Use (Sizing)	The *Energy Use (Sizing)* worksheet contains data used to determine the input capacity of existing boilers based on building characteristics.
Energy Price*	The *Energy Price* worksheet shows the estimated monthly natural gas, electricity, and oil prices.
Energy Price Trends*	The *Energy Price Trends* worksheet shows the future price trends of the different heating fuels. DOE used energy price data and forecasts from the Energy Information Administration's (EIA's) *Annual Energy Outlook 2015* (*AEO 2015*) until 2040 and extrapolated beyond 2040.[3]
Discount Rate*	The *Discount Rate* worksheet contains the distributions of discount rates for replacement and new units.
Lifetime*	The *Lifetime* worksheet contains the distribution of lifetimes for equipment of that product class.
Energy Use Adjustment Factors*	The *Energy Use Adjustment Factors* worksheet contains adjustment factors for normal heating degree days and cooling degree days, as well as building shell efficiency index.
Weather Data*	The *Weather Data* worksheet contains heating degree days, cooling degree days, heating and cooling outdoor design temperature, and annual mean temperature by weather station.
Labels	The *Labels* worksheet contains labels used in graphical user interface.

Forecast Cells The *Forecast Cells* worksheet contains the outcome of the Monte Carlo simulations for the sample of 10,000 households and commercial buildings for many parameters used in the analysis and the documentation.

LCC Outputs The *LCC Outputs* worksheet contains intermediate inputs used for DOE's National Impact Analysis. These inputs include fuel and electricity use, total installed price, operating cost, and base case distributions for each product class and efficiency level. The inputs are presented for replacement and new construction housing markets.

* Results displayed in these worksheets are for only one household, not the entire sample.

Figure 8A.3.1 depicts how these various inputs are used to generate the LCC and PBP outputs.

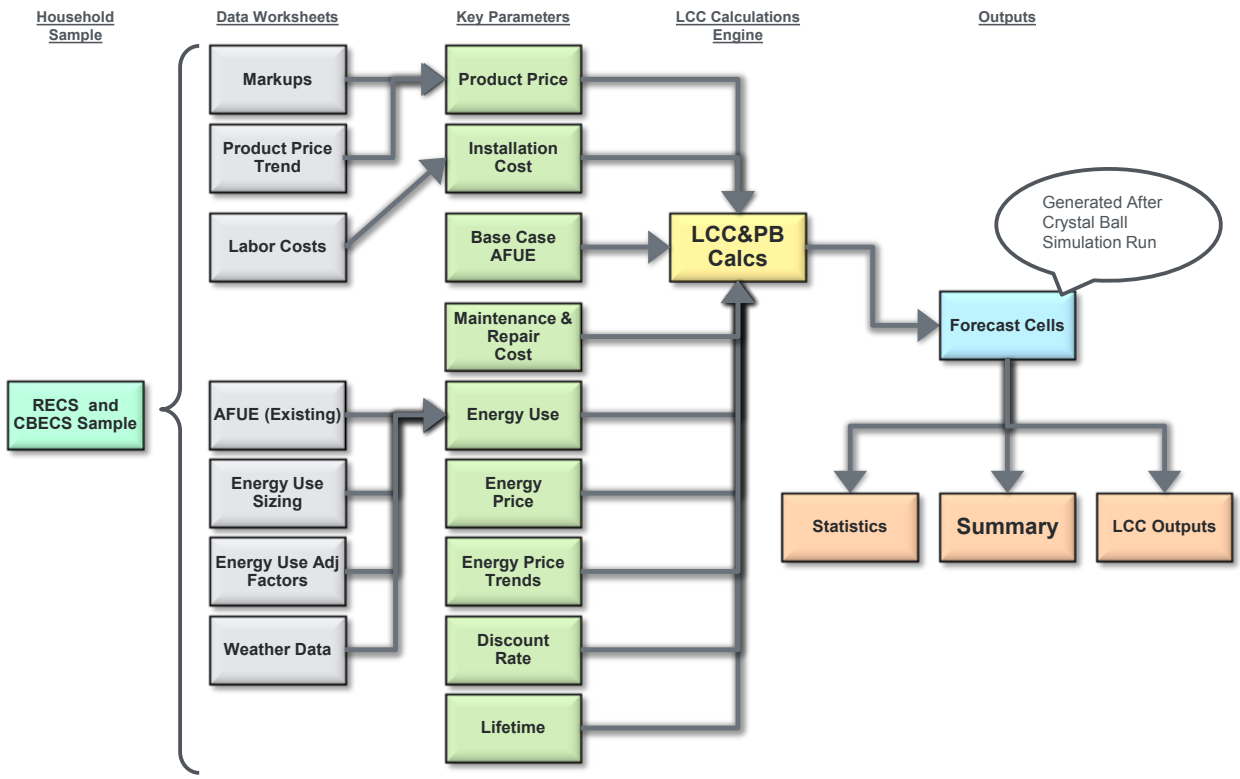

Figure 8A.3.1 LCC and Payback Calculation Process

8A.3.2 Analysis Input Worksheet

The analysis input spreadsheet contains the following worksheets:

Markup Input The *Markup Input* worksheet contains the data used to derive the markups by RECS and CBECS regions for the market participants.

Labor Cost Data The L*abor Cost Data* worksheet contains the labor cost factors by RECS and CBECS regions and RS Means labor cost data.

RECS Sample	The *RECS Sample* worksheet contains the calculations used to determine the residential households from the RECS sample used in the LCC analysis to represent the boilers households in US.
CBECS Sample	The *CBECS Sample* worksheet contains the calculations used to determine the commercial buildings from the CBECS sample that use residential-size boilers.
Sample Stats	The *Sample Stats* worksheet contains summary statistics from the RECS and CBECS samples used in the analysis.
RECS Codebook	The *RECS Codebook* worksheet provides details about the RECS variables used in the analysis.
Res Energy Price Input	The *Res Energy Price Input* worksheet contains the derivation of the residential energy prices by RECS regions used in the analysis.
Res Energy Price Proc	The *Res Energy Price Proc* worksheet is an intermediate sheet used in deriving residential energy prices.
Res Energy Price Data	The *Res Energy Price Data* worksheet contains historic data used to derive the residential energy prices.
Res Energy Price (Other)	The *Res Energy Price (Other)* worksheet contains data used to derive the residential energy prices.
Com Energy Price Input	The *Com Energy Price Input* worksheet contains the derivation of the commercial energy prices by CBECS regions used in the analysis.
Com Energy Price Proc	The *Com Energy Price Proc* worksheet is an intermediate sheet used in deriving commercial energy prices.
Com Energy Price Data	The *Com Energy Price Data* worksheet contains historic data used to derive the commercial energy prices.
Com Energy Price (Other)	The *Com Energy Price Other* worksheet contains data used to derive the commercial energy prices.
Energy Price Trends (to LCC)	The *Energy Price Trends (to LCC)* worksheet contains the derivation of the energy price trends used in the LCC analysis. It includes the data used for the derivation.
Energy Price Trends (to NIA)	The *Energy Price Trends (to NIA)* worksheet contains the derivation of the energy price trends used in the NIA analysis. It includes the data used for the derivation.
AFUE Existing	The *AFUE (Existing)* worksheet contains the derivations of the AFUE percentiles by year installed for all boiler product classes.
Base Case Eff	The *Base Case Eff* worksheet contains the derivation of the no-new-standards case efficiency distributions and the data used for the derivation.

Base Case Eff - FR	The *Base Case Eff - FR* worksheet contains the data and calculations to derive the fractions of boiler installed by type.
Models Directory	The *Models Directory* worksheet contains the models data used in the analysis.
Equip Specs	The *Equip Specs* worksheet contains summary statistics for the characteristics of the models used in the analysis.
Equip Specs Charts	The *Equip Spec Charts* worksheet contains charts showing the distribution of input capacity and AFUE for the models used in the analysis.
Average HDD_CDD	The *Average HDD_CDD* worksheet contains derivation for the residential and commercial HDD and CDD used in the analysis.
Energy Use Adj Factors	The *Energy Use Adj Factors* worksheet contains the Building Shell Efficiency Index and heating degree days from EIA used in the analysis.
Energy Use Trend (for NIA)	The *Energy Use Trend (for NIA)* worksheet contains derivations for the energy use trend by product class based on projections from EIA.
Shipments	The *Shipments* worksheet contains the shipments data used in the analysis.
Weather Data	The *Weather Data* worksheet contains NOAA's weather data for 297 US weather stations.
Lifetime (REF)	The *Lifetime (Ref)* worksheet contains a list of reference found in DOE's literature review regarding boiler lifetime.
Warranty (REF)	The *Warranty (Ref)* worksheet contains a list of references used to derive the boiler manufacturer warranties.
Energy Price Factor Trends	The *Energy Price Factor Trends* worksheet contains the derivations of the Energy Price Trends for the NIA (based on the *AEO 2015*).
Definitions	The *Definitions* worksheet contains the definitions of variables used in the analysis.

Each of those worksheets is designed to calculate the input that will be used in the corresponding worksheet in the main LCC or NIA spreadsheets.

8A.4 BASIC INSTRUCTIONS FOR OPERATING THE LIFE-CYCLE COST SPREADSHEETS

Basic instructions for operating the LCC spreadsheet are as follows:

1. Once the LCC spreadsheet has been downloaded, open the file using Excel. Click "Enable Macro" when prompted and then click on the tab for the *Summary* worksheet.

2. Use Excel's View/Zoom commands at the top menu bar to change the size of the display to fit your monitor.

3. The user can change the parameters listed under "Analysis User Variables" and "User Options" on the *Summary* worksheet. There are three drop-down boxes and one command button. The default parameters are:

    a. Start Year: Defaults to "2021." To change the value, input the desired year.[b]

    b. # of Trials: Defaults to "10,000." To change the value, input the desired number of trials.

    c. Energy Price Trend: Defaults to "AEO 2015 - Reference Case." To change the input, use the drop-down menu and select the desired trend (Reference, High, or Low).

    d. Equipment Price Trend: Defaults to "Constant (Default)." To change the value, use the drop-down menu and select the desired trend (Constant (Default), Increasing, or Decreasing).

4. To run the Crystal Ball simulation, click the "run" button (you must re-run after changing any parameters). The spreadsheet will then be minimized. You can monitor the progress of the simulation by watching the count of iterations at the left bottom corner. When the simulation is finished, the worksheet named *Summary* will reappear with the results.

[b] Note that if the start year is changed, the results will be an approximation because the relevant inputs are for 2021.

REFERENCES

1. U.S. Department of Energy–Energy Information Administration. *2009 RECS Survey Data*. (Last accessed October 13, 2015.) http://www.eia.gov/consumption/residential/data/2009/.

2. U.S. Department of Energy–Energy Information Administration. *2003 CBECS Survey Data*. (Last accessed October 13, 2015.) http://www.eia.gov/consumption/commercial/data/2003/index.cfm?view=microdata.

3. U.S. Energy Information Administration. *Annual Energy Outlook 2015 with Projections to 2040*. 2015. Washington, D.C. Report No. DOE/EIA-0383(2015). (Last accessed October 13, 2015.) http://www.eia.gov/forecasts/aeo/pdf/0383(2015).pdf.

APPENDIX 8B. UNCERTAINTY AND VARIABILITY IN THE LCC ANALYSIS FOR RESIDENTIAL BOILERS
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APPENDIX 8B. UNCERTAINTY AND VARIABILITY IN THE LCC ANALYSIS FOR RESIDENTIAL BOILERS

8B.1 INTRODUCTION

Analysis of energy conservation standards involves calculations of impacts, for example, the impact of a standard on consumer life-cycle cost (LCC). In order to perform the calculation, the analyst must: 1) specify the equation or model that will be used; 2) define the quantities in the equation; and 3) provide numerical values for each quantity. In the simplest case, the equation is unambiguous (contains all relevant quantities and no others), each quantity has a single numerical value, and the calculation results in a single value. However, unambiguity and precision are rarely the case. In almost all cases, the model and/or the numerical values for each quantity in the model are not completely known (*i.e.*, there is uncertainty) or the model and/or the numerical values for each quantity in the model depend upon other conditions (*i.e.*, there is variability).

Thorough analysis involves accounting for uncertainty and variability. While the simplest analysis involves a single numerical value for each quantity in a calculation, arguments can arise about what the appropriate value is for each quantity. Explicit analysis of uncertainty and variability is intended to provide more complete information to the decision-making process.

8B.2 UNCERTAINTY

When making observations of past events or speculating about the future, imperfect knowledge is the rule rather than the exception. For example, the energy actually consumed by a particular appliance type (such as the average U.S. water heater, direct heating equipment, or pool heater) is not directly recorded, but rather estimated based upon available information. Even direct laboratory measurements have some margin of error. When estimating numerical values expected for quantities at some future date, the exact outcome is rarely known in advance.

8B.3 VARIABILITY

Variability results when different applications or situations produce different numerical values when calculating a quantity. Specifying an exact value for a quantity may be difficult because the value depends on something else. For example, water heater energy consumption depends upon the specific circumstances and behaviors of the occupants (*e.g.*, number of persons, length and temperature of showers, etc.). Variability makes specifying an appropriate population value more difficult inasmuch as any one value may not be representative of the entire population. Surveys can be helpful here, and analysis of surveys can relate the variable of interest (*e.g.*, hours of use) to other variables that are better known or easier to forecast (*e.g.*, persons per household).

8B.4 APPROACHES TO UNCERTAINTY AND VARIABILITY

This section describes two approaches to uncertainty and variability:

- scenario analysis, and
- probability analysis.

Scenario analysis uses a single numerical value for each quantity in a calculation, then changes one (or more) of the numerical values and repeats the calculation. A number of calculations are done, which provide some indication of the extent to which the result depends upon the assumptions. For example, the life-cycle cost of an appliance could be calculated for energy rates of 2, 8, and 14¢ per kWh.

The advantages of scenario analysis are that each calculation is simple; a range of estimates is used and crossover points can be identified. (An example of a crossover point is the energy rate above which the life-cycle cost is reduced, holding all other inputs constant. That is, the crossover point is the energy rate at which the consumer achieves savings in operating expense that more than compensate for the increased purchase expense.) The disadvantage of scenario analysis is that there is no information about the likelihood of each scenario.

Probability analysis considers the probabilities within a range of values. For quantities with variability (*e.g.*, electricity rates in different households), surveys can be used to generate a frequency distribution of numerical values (*e.g.*, the number of households with electricity rates at particular levels) to estimate the probability of each value. For quantities with uncertainty, statistical or subjective measures can be used to provide probabilities (*e.g.*, manufacturing cost to improve energy efficiency to some level may be estimated to be $10 ± $3).

The major disadvantage of the probability approach is that it requires more information, namely information about the shapes and magnitudes of the variability and uncertainty of each quantity. The advantage of the probability approach is that it provides greater information about the outcome of the calculations; that is, it provides the probability that the outcome will be in a particular range.

Scenario and probability analysis provide some indication of the robustness of the policy given the uncertainties and variability. A policy is robust when the impacts are acceptable over a wide range of possible conditions.

8B.5 PROBABILITY ANALYSIS AND THE USE OF CRYSTAL BALL

To quantify the uncertainty and variability that exist in inputs to the engineering, LCC, and payback period (PBP) analyses, DOE used Microsoft Excel spreadsheets combined with Crystal Ball, a commercially available add-in, to conduct probability analyses. The probability analyses used Monte Carlo simulation and probability distributions.

Simulation refers to any analytical method meant to imitate a real-life system, especially when other analyses are too mathematically complex or too difficult to reproduce. Without the aid of simulation, a spreadsheet model will only reveal a single outcome, generally the most

likely or average scenario. Spreadsheet risk analysis uses both a spreadsheet model and simulation to automatically analyze the effect of varying inputs on outputs of the modeled system. One type of spreadsheet simulation is Monte Carlo simulation, which randomly generates values for uncertain variables again and again to simulate a model. Monte Carlo simulation was named for Monte Carlo, Monaco, where the primary attractions are casinos containing games of chance. Games of chance, such as roulette wheels, dice, and slot machines, exhibit random behavior. The random behavior in games of chance is similar to how Monte Carlo simulation selects variable values at random to simulate a model. When you roll a die, you know that a 1, 2, 3, 4, 5, or 6 will come up, but you do not know which for any particular roll. The same applies to the variables that have a known range of values but an uncertain value for any particular time or event (*e.g.*, equipment lifetime, discount rate, and installation cost).

For each uncertain variable (one that has a range of possible values), possible values are defined with a probability distribution. The type of distribution selected is based on the conditions surrounding that variable. Probability distribution types include:

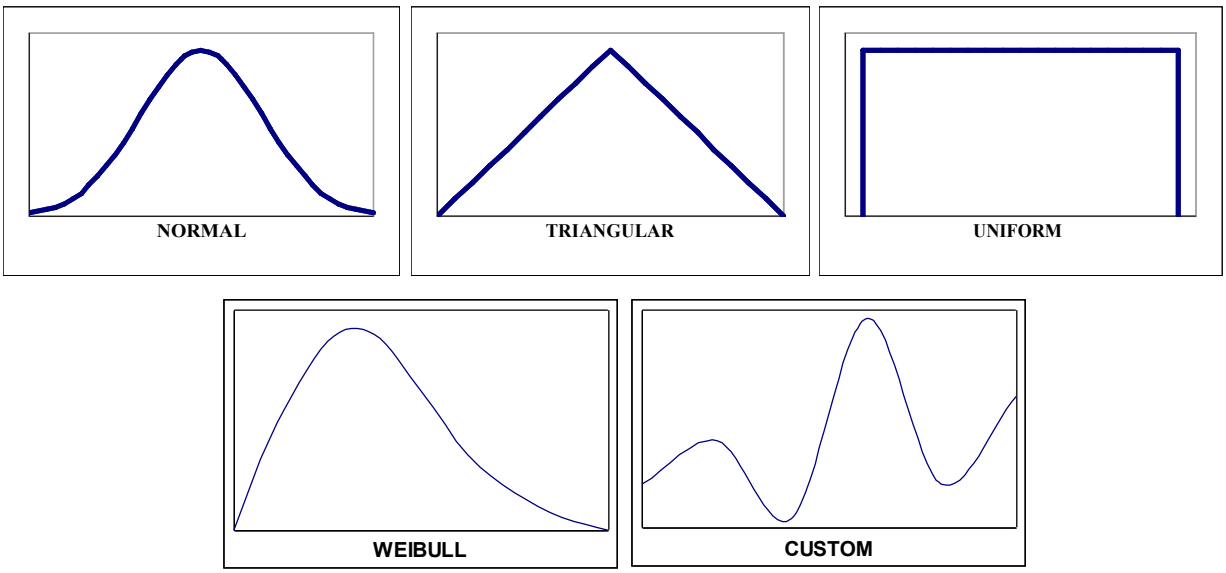

Figure 8B.5.1 Normal, Triangular, Uniform, Weibull, and Custom Probability Distributions

During a simulation, multiple scenarios of a model are calculated by repeatedly sampling values from the probability distributions for the uncertain variables and using those values for the cell. Crystal Ball simulations can consist of as many trials (or scenarios) as desired—hundreds or even thousands. During a single trial, Crystal Ball randomly selects a value from the defined possibilities (the range and shape of the probability distribution) for each uncertain variable and then recalculates the spreadsheet.

APPENDIX 8C. INSTALLATION COST DETERMINATION FOR RESIDENTIAL BOILERS

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APPENDIX 8C. INSTALLATION COST DETERMINATION FOR RESIDENTIAL BOILERS

8C.1 INTRODUCTION

The installation cost is the price to the consumer of labor and materials (other than the cost of the actual product) needed to install a residential boiler product. This appendix provides further details about the derivation of installation costs for boilers for AFUE standards. For standby and off mode standards, DOE assumed no additional installation costs.

The Department of Energy (DOE) estimated installation costs for boilers based on RS Means, a well-known and respected construction cost estimation method, as well as manufacturer literature and information from expert consultants. Table 8C.1.1 offers an example of the installation cost calculation. All labor costs are derived using the latest residential 2015 RS Means labor costs by crew type.[1] Replacement installation cost tables include a trip charge, which is often charged by contractors and calculated to be equal to one half hour of labor per crew member. Labor hours (or person-hours) are based on RS Means data, expert data, or engineering judgment. Bare costs are the costs without any markups. Material costs are based on RS Means data, expert data, or internet sources. The total includes overhead and profit (O&P), which is calculated using labor and material markups from RS Means. Values reported in this appendix are based on national average labor costs. The labor costs shown in the tables in this appendix are the national average values. In its analysis, DOE used regional labor costs to more accurately estimate installation costs by region. Section 8C.3 describes the derivation of regional labor costs. DOE then applied the appropriate regional labor cost to each RECS 2009 household or CBECS 2003 building. The total costs include O&P. (Note that the unit "L.F." in the tables means "linear foot.")

Table 8C.1.1 Example Installation Cost Table

Description	Crew	Labor Hours	Unit	Bare Costs *(2014$)*			Quantity	Total incl. O&P
				Material	Labor	Total		
Trip Charge	CREW1	0.5	-	0.00	23.00	23.00	1	35.00
Description of Installation Item	CREW1	0.5	Ea.	15.00	23.00	48.00	1	51.50
Total		1.0		15.00	46.00	71.00		**86.50**

The installation cost calculations for boilers encompass a broad array of product classes, installation sizes, and venting configurations, including:

- gas-fired hot water boilers, gas-fired steam boilers, oil-fired hot water boilers, and oil-fired hot water boilers;[a]
- new construction, new owner, and replacement markets;

[a] DOE did not calculate any installation costs for electric hot water boilers and electric steam boilers, which are only analyzed for standby and off mode standards.

- single-family, multi-family, and commercial buildings;
- venting systems that are Category I (non-condensing), Category III (stainless steel), or Category IV (condensing);[b]
- various vents, such as masonry chimneys, metal vents, stainless steel vents, or plastic vents;
- single-wall or double-wall vent connectors;
- gas or oil water heaters that are either vented in common with a boiler or isolated; and
- special situations, such as the need to reline a chimney or vent an orphaned water heater.

Applying the RS Means methodology to a boiler installation requires knowledge of its details, including the vent length, venting material, vent type, diameter, number of elbows, *etc*. DOE reviewed relevant literature, data, and installation manuals to estimate these quantities as a distribution of values derived from available data. A Crystal Ball Monte Carlo simulation[c] was used to model the resultant costs for each individual household.

8C.2 INSTALLATION COST METHODOLOGY

8C.2.1 Introduction

DOE developed installation cost data for boilers using RS Means cost data, DOE technical support documents, and consultant reports prepared for this analysis.[1,2,3,4,5] The installation cost was divided into the following four components:

- basic installation,
- venting, and
- condensate removal

The following information about market shares, technologies, and installation location helped to shape the installation cost calculations.

8C.2.2 Installation Inputs

New Construction, New Owner, and Replacement Market Shares. As determined in the shipment analysis portion of the national impact analysis (NIA) (see chapter 9), DOE estimated that the new construction market accounts for 10 percent of gas-fired hot water boilers, zero percent of gas-fired steam boilers, two percent of oil-fired hot water boilers, and zero percent of oil-fired steam boilers in 2021. For gas-fired hot water boilers, DOE estimated that the new owner market accounts for 18 percent of boiler installations in 2021.

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[b]

[c] See chapter 8 for a description of the Monte Carlo simulation methodology.

Residential and Commercial Market Shares. As determined in the shipments analysis (see chapter 9), approximately 93 percent of residential boilers are shipped to the residential sector and 7 percent are shipped to the commercial sector in 2021.

Boiler Technologies. There are two main boiler designs: non-condensing and condensing. Non-condensing boilers have an AFUE of less than 90 percent. Condensing boilers have an AFUE of 90 percent or greater. Non-condensing boilers usually use Category I or Category III venting systems, while condensing boilers are vented using Category IV venting systems. A Category I venting system relies on negative pressure and uses either a masonry chimney or a metal vent. A Category III venting system relies on positive pressure and uses stainless steel. A Category IV venting system uses positive pressure and a plastic vent.

Installation Locations. Table 8C.2.1 shows the fraction of installations by installation location. The installation fractions are derived using RECS 2009 household characteristics together with the following assumptions:[6]

1) If a household has a *basement*,[d] then the boiler is installed in the basement.
2) If the household has a *garage*, then the boiler is installed in the garage.
3) If the household has neither a basement nor garage, then it is assumed that the boiler is installed in a location classified as "other."[e]

Table 8C.2.1 Boiler Installation Locations

Boiler Location	Gas Boilers	Oil Boilers
Basement (Conditioned)	35%	40%
Basement (Unconditioned)	27%	49%
Garage	8%	4%
Other Locations	30%	7%

DOE assumed that residential boilers installed in commercial buildings are located in "other locations" indoors.

8C.2.3 Basic Installation Cost

DOE estimated basic installation cost that is applicable to both replacement and new construction installations. This cost includes putting in place and setting up the boiler, permit, and removal or disposal fees. Table 8C.2.2 presents the national average basic installation cost applied to all efficiency levels for all product classes.

[d] DOE distinguished between conditioned and unconditioned basements when deriving the annual energy use of a particular household.
[e] "Other" locations include indoor closets, utility rooms, and exterior closets.

Table 8C.2.2 National Average Basic Installation Cost

Product Class	Basic Installation Cost *2014$*
Gas-Fired Hot Water Boilers	$2,741
Gas-Fired Steam Boilers	$2,917
Oil-Fired Hot Water Boilers	$2,818
Oil-Fired Steam Boilers	$2,894

8C.2.4 Venting

Estimating venting costs is complex because there are a large variety of installation scenarios that are possible. DOE calculated venting costs for each household in the RECS 2009 or CBECS 2003 residential boiler sample. To determine venting costs for both new construction and replacement installations, DOE used a number of parameters that have an impact on the venting installation cost, including vent location, installation type (replacement or new construction), vent material (masonry, metal, or plastic), vent connectors, vent length, and chimney type (exterior or interior and lined or unlined). The methodologies for determining these costs and the vent length are discussed in the following sections.

Non-condensing boilers exhaust high-temperature flue gas, which heats the inside of the vent above the dew point to ensure that water vapor in the flue gas does not condense. If the flue gas does condense and does not re-evaporate quickly during the boiler firing cycle, the condensate could corrode the vent, the boiler heat exchanger, or both, thus reducing the lifetime of the vent system or the boiler itself. Typically, a small amount of condensate at cold startup is acceptable as long as it dries out quickly. More-efficient low-temperature condensing boilers condense the water vapor in the primary or a secondary heat exchanger, thus increasing boiler efficiency by reducing latent heat loss. The condensate is disposed of through a drain. Because the flue gas temperature is relatively low, condensing boilers can be vented through plastic piping.

Non-condensing boiler installations could require chimney relining or vent resizing for replacements and a new metal vent for new construction and new owners. Condensing boilers require new plastic venting or could have orphaned water heater venting issues in replacement, new owner, and new construction installations.

8C.2.4.1 Venting Types

Masonry chimneys, metal vents, and plastic piping are the most common venting assemblies. Details of these types of installation follow.

Masonry Chimney. Some non-condensing boilers are vented using masonry chimneys, either lined or unlined. Figure 8C.2.1 shows a lined masonry chimney venting a non-condensing boiler and a water heater. For unlined chimneys, the flexible liner shown is not present, and a clay tile liner is used instead. Since the 1970s, chimney construction techniques have changed. For newer

chimneys, the chimney and clay tile liner is usually replaced by a masonry facade on the exterior that covers a wooden chase with a flexible metal liner on the interior. (These are faster to build compared to brick by brick.) If the water heater is isolated,[f] the common water heater vent shown in Figure 8C.2.1 would not be present.

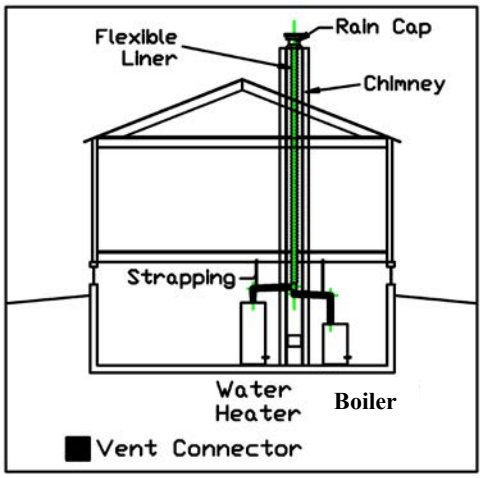

Figure 8C.2.1 Masonry Chimney Venting Installation (Non-Condensing Boiler)

Metal Vents. Some non-condensing boilers are vented using metal vents, either single wall or Type B double wall. Figure 8C.2.2 shows a Type B double-wall metal vent. The combination of wall thimbles, storm collar, and flashing replace the chimney. Most metal vents go straight through the roof. If the water heater is isolated, the common water heater vent shown would not be present.

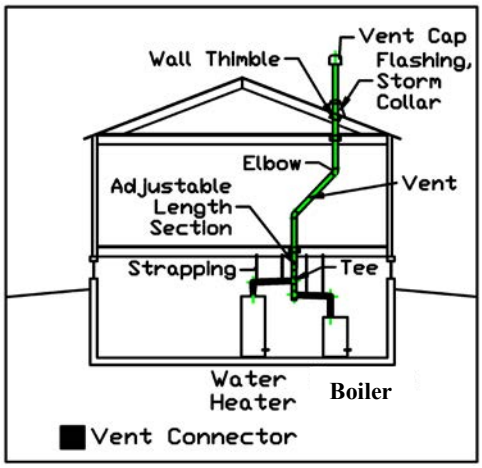

Figure 8C.2.2 Metal Venting Installation (Non-Condensing Boiler)

[f] There are a number of water heater types that would not be vented in common with a boiler. These include electric, gas direct side-vented, and gas power-vented water heaters. In this appendix, the term "isolated" water heater is defined to include all of these possibilities, but only the most prevalent (more than 90 percent) option – electric water heaters – is modeled.

Plastic Venting. All condensing boilers are vented using plastic vents, either horizontal or vertical. Figure 8C.2.3 shows a horizontal side-wall plastic vent. The boiler installation shown below utilizes a two-plastic-pipe venting system. One of the vents exhausts the flue gases while the other brings combustion air from the outside to the boiler. Flue gas piping is sloped downward toward the boiler so that condensate drips back into the boiler condensate drain. This installation includes a gas water heater (analogous to the common vented scenario above), which requires a separate flue gas exhaust vent. If the water heater is isolated, this exhaust vent will not be present.

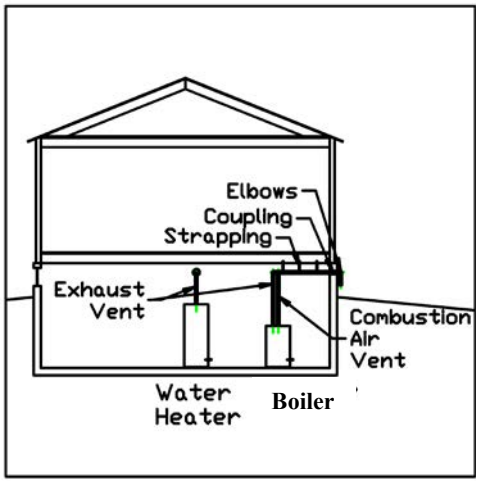

Figure 8C.2.3 Plastic Vent Installation (Condensing Boiler)

Vent Sizing. DOE included a capacity-dependent methodology for determining vent sizes for the boiler population. The vent sizes included a range from 2" to 6" for various materials. For example, a representative 100 kBtu/h non-condensing gas boiler uses a 5" Type B vent, while a representative 140 kBtu/h non-condensing gas boiler uses a 6" Type B vent. Condensing boilers were assigned either 2" or 3" polyvinyl chloride (PVC), polypropylene (PP), or chlorinated polyvinyl chloride (CPVC) vents.[g]

Table 8C.2.3 provides the fraction of existing masonry chimneys and metal vent installations by region used in the analysis, based on a 1994 GRI Furnace Survey.[7] DOE assumed that the fractions from this survey are applicable to boilers.

Table 8C.2.3 Fractions of Existing Chimney Installations

Venting Type	Northeast	Midwest	South	West
Masonry	73%	53%	10%	27%
Metal Vent	27%	47%	90%	73%

[g] DOE assumed that 75 percent of installations would install a 2" PVC, PP, or CPVC ventDOE also assumed that 75 percent of installations would install a PVC or PP vent compared to 25 percent installing a CPVC vent.

Table 8C.2.4 provides the fraction of existing non-condensing installations that are commonly vented with gas water heaters, based on a 1991 GTI water heater survey.[8] DOE assumed that the fractions from this survey are applicable to boilers with a separate same fuel water heater.

Table 8C.2.4 Fraction of Commonly Vented Furnace or Boiler and Water Heater Installations

Common Venting	Northeast	Midwest	South	West
Common	78%	68%	22%	65%
Isolated	22%	32%	78%	35%

8C.2.4.2 Vent Pipe Length

Figure 8C.2.4 shows the vent pipe length determination methodology. DOE separately determined the vent length for vertical (through the roof) or horizontal (through the wall) vent applications.

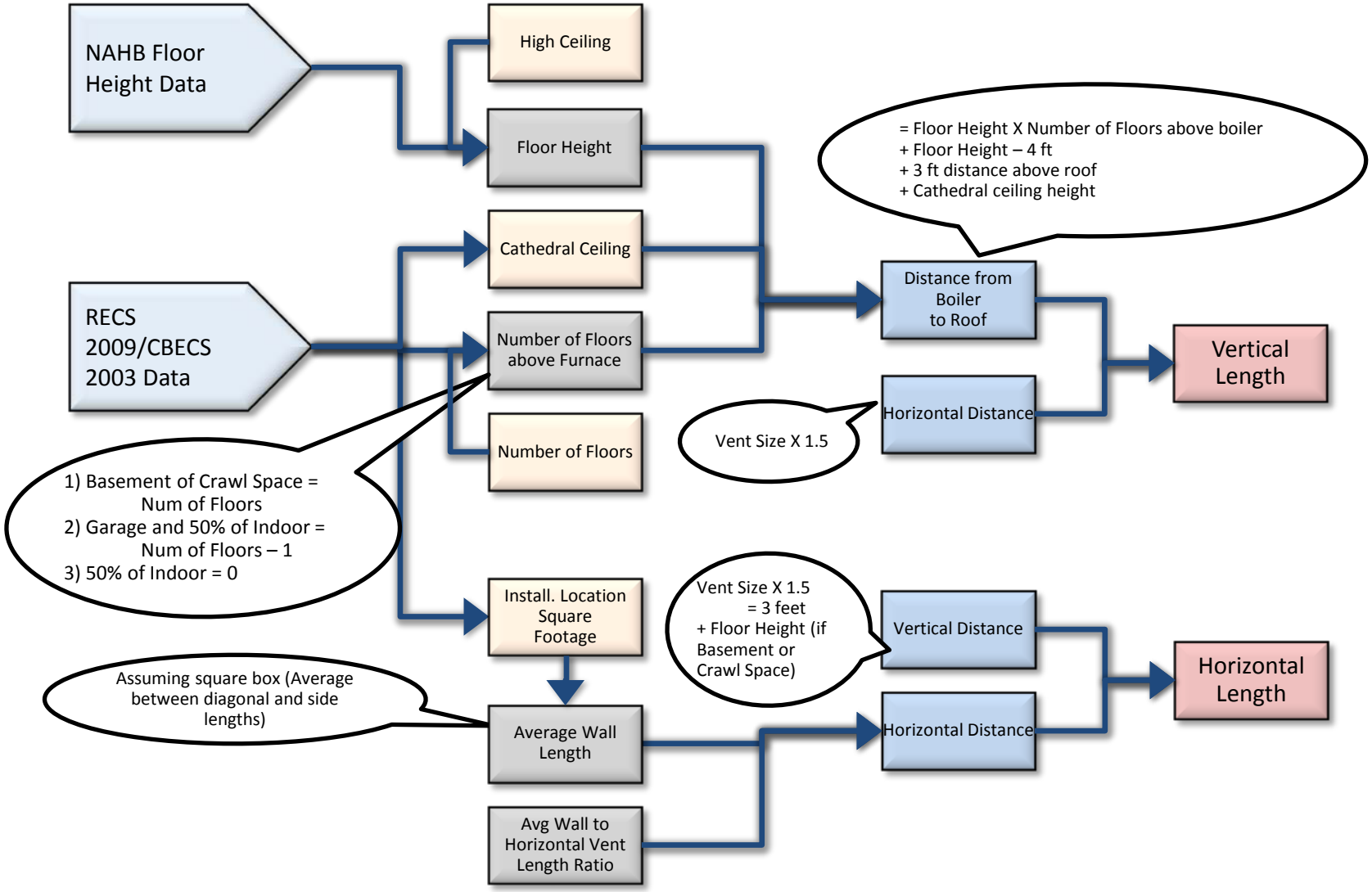

Figure 8C.2.4 Vent Pipe Length Determination

Vent pipe length is determined by taking into account:

- boiler location in the house,
- ceiling height,
- number of floors above boiler, and
- square footage of boiler installation location.

DOE assumed that all non-condensing boiler vent types (*i.e.*, masonry chimneys and metal vents) are vented vertically. DOE assumed that the shortest run between horizontal and vertical venting determined the vent length and orientation of condensing boiler PVC venting.

To determine the vertical pipe length, DOE used data from RECS 2009 or CBECS 2003 on the number of floors, installation location, and presence of a cathedral ceiling or high ceiling (peach-colored items) as well as data from National Association of Home Builders (NAHB) on floor height (see Figure 8C.2.5).[9] These data were used to determine the number of floors above the boiler and the resulting distance from the boiler to the roof. A horizontal distance is also applied to take into account the horizontal vent pipe length for the vent connector in a common vent installation.

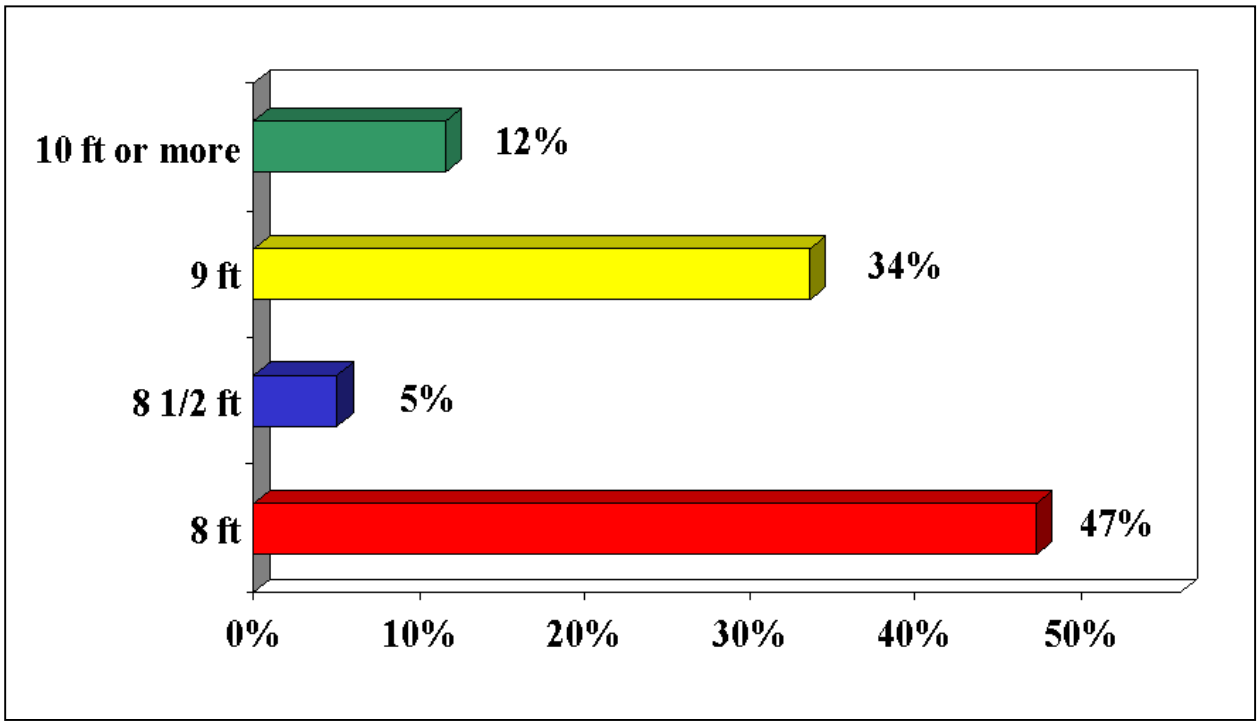

Figure 8C.2.5 First Floor Height Fractions from 2001 NAHB Survey

To determine the horizontal pipe length, DOE used the square footage of the house reported in RECS 2009 or CBECS 2003 to determine the average wall length. DOE used a triangular probability distribution to represent the average ratio between the wall length and horizontal vent length (see Figure 8C.2.6). The average wall length and ratio of wall length to

horizontal vent length were used to determine the pipe horizontal length. DOE also considered the vertical vent length that is required based on the floor height and whether the boiler is in a basement. The vertical vent height is assumed to be high enough to be above the snow level in the winter months.

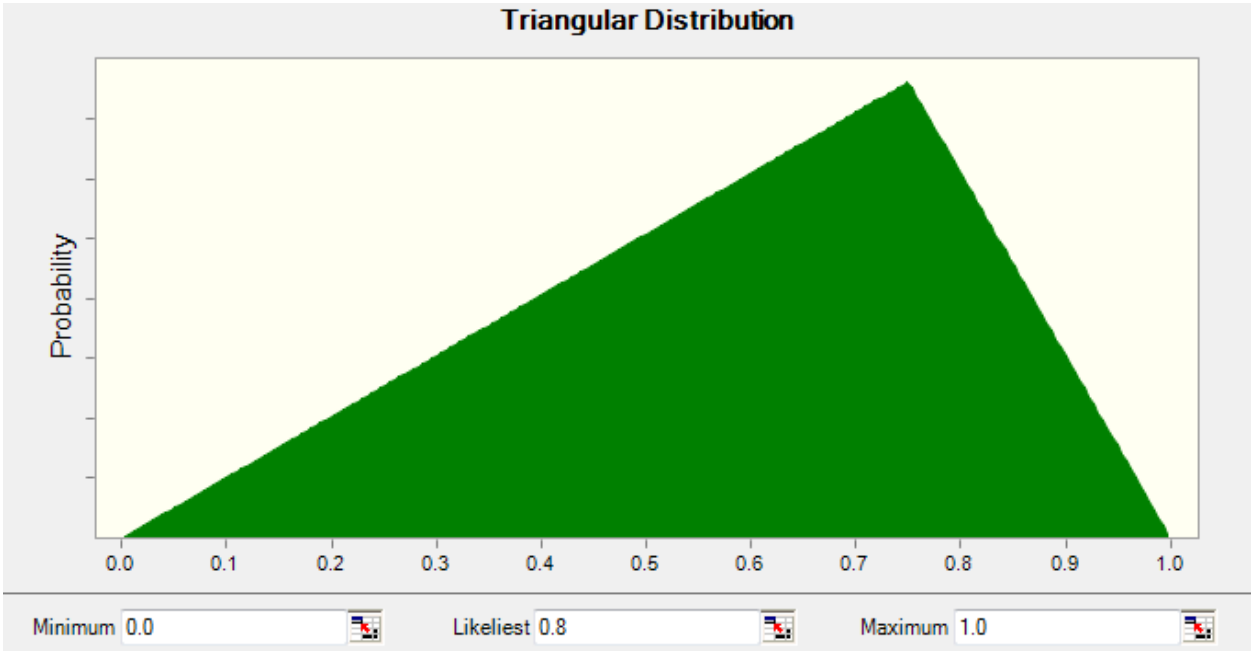

Figure 8C.2.6 Average Wall to Horizontal Vent Length Ratio

In addition to the vent pipe length, DOE account for various vent pipe components, including number of elbows and different cost vent wall penetration depending on wall type.

8C.2.4.3 Replacement Installations

For replacements, DOE evaluated two cases. One involves switching from a non-condensing natural draft boiler (less than 75 percent AFUE) to a non-condensing fan-assisted boiler (82 percent AFUE); the other involves switching from a non-condensing (natural draft and fan-assisted) to a condensing boiler (90 percent or greater AFUE).

8C.2.4.3.1 Non-Condensing to Non-Condensing Boiler Installations

Many non-condensing to non-condensing boiler replacement installations require venting modifications to meet current safety requirements. There are two main issues that can arise when replacing a non-condensing boiler with a more efficient non-condensing boiler: relining an unlined chimney and resizing an existing venting system.

Chimney Relining

There are two types of masonry chimney—interior and exterior. Exterior chimneys are usually exposed on three sides; they are less insulated by the structure, lowering the internal temperature and making it more likely that exhaust gases will condense inside. Interior chimneys are surrounded by the heated building; the temperature in the chimney tends to be higher, so flue gases are less likely to condense. Because of these different insulating properties, the National Fuel Gas Code (NFGC)[10] has different lining requirements for interior and exterior chimneys. These requirements are important, because the cost of chimney relining is a major component of a boiler installation cost.

Exterior Chimneys. Prior to 1995, building codes did not require lining of chimneys. In Table 13.11 of the NFGC,[10] the minimum allowable input rating for appliances that are vented in exterior unlined masonry chimneys is 150 kBtu/hour. This rating is close to the representative input capacity for residential boilers assumed in this analysis. Therefore, DOE assumed that all exterior chimneys will require re-lining upon replacement if the building was built before 1995 or if the existing boiler was installed before 1995.

Interior Chimneys. Prior to 1995, building codes did not require lining of chimneys. The NFGC mandates that all interior chimneys be relined when the boiler is isolated from the water heater (NFGC Tables 13.3 and 13.4).[10] When a boiler is vented in common with a water heater, the vertical vent upsizing / 7X rule applies. This rule specifies that the flow area of the vertical vent shall not exceed seven times (7X) the flow area of the smallest vent connector—the vent connector for the water heater, for example. Water heater vents are typically 3 inches in diameter, so an interior masonry chimney cannot exceed 49 square inches, corresponding to an 8 x 8 nominal chimney liner size. DOE assumed that all interior chimneys would need to be relined if the home was built before 1995 and if the existing boiler is a natural draft boiler.

DOE determined which boiler installations of the entire boiler sample would require chimney relining, based on RECS 2009 equipment age data and the fraction of chimney installations (see Table 8C.2.3). For each bin DOE assigned an equipment installation year using a uniform distribution with the ranges shown in the table. Using the fraction of chimney installations shown in Table 8C.2.3, DOE determined if the household had a chimney installation. To determine if a household had an unlined chimney, DOE used the following two criteria:

1) Boiler exhaust gases are vented through a chimney, and
2) The existing boiler was installed before 1995 when building codes requiring the relining of chimneys were not yet in place.

Based on these criteria, DOE calculated that 6 percent of hot water gas-fired boilers, 7 percent of steam gas-fired boilers, 7 percent of hot water oil-fired boilers, and 2 percent of steam oil-fired boilers installations in the replacement market would need to be relined in 2021.

DOE used chimney liner prices for different liner types (aluminum or stainless steel) and sizes (3 inches to 6 inches) from an online vent vendor. DOE assumed that oil-fired boilers require stainless steel chimney liners. Table 8C.2.5 lists the liner cost data.

Table 8C.2.5 Chimney Liner Costs[h]

Nominal Size	Aluminum Liner Costs				Orig. DOE Estimate ($/ft)
	Mfg.	PN	Kit Cost	Avg $/ft	
3"	Metalbest	AF25 - 03	153.30 (25ft)	6.13	8.91
4"	Metalbest	AF25 - 04	161.74 (25ft)	6.47	12.64
5"	Metalbest	AF25 - 05	193.88 (25ft)	7.76	25.28
6"	Metalbest	AF35 - 06	278.50 (35ft)	7.96	37.92
Stainless Steel Liner Cost					
6"	Metalbest	6RF25IK	966.48 (25ft)	38.66	37.92

Vent Resizing

Vent resizing occurs when the existing vent diameter is too large for the new gas boiler or for the commonly vented boiler and gas water heater. Two solutions are possible: 1) vent connector resizing (most common) or 2) vent resizing (less common). There are three main types of Category I vents: Type B double wall, single-wall galvanized steel, and single-wall aluminum. A Type B double-wall vent uses a galvanized steel outer tube to surround an aluminum inner tube and is sold in multiple section lengths. The air gap in between the tubes provides insulation, which reduces the likelihood of condensation in the vent connector. A single-wall galvanized steel vent is simply a zinc-coated steel tube vent. Aluminum single-wall vents are similar to galvanized steel single-wall vents and are found in some regions. Condensing boilers do not require metal vents.

The vent connector portion of the vent is the horizontal part of the masonry and metal vent systems shown in Figure 8C.2.1 and Figure 8C.2.2, respectively. In each figure there are two vent connectors shown: one for the water heater, and one for the boiler. As water heater capacity is typically less than boiler capacity, in many cases the water heater vent connector diameter will be less than the boiler vent connector diameter. DOE assumed that the existing boiler vent connector diameter is 5 inches on average, while an existing water heater vent connector is 3 inches on average.

[h] Burnham Holdings, Public Comment, Document ID: EERE-2012-BT-STD-0047-0060, p. 26.

DOE assumed that vent resizing or a vent connector upgrade occurs only when a non-condensing fan-assisted boiler (an AFUE less than 90 percent) replaces a natural draft non-condensing boiler (an AFUE of less than 75 percent). DOE assumed that in such cases, vent resizing is required in 10 percent of these installations and new vent connector is required in 75 percent of these installations. Although fan-assisted boilers have been installed non-condensing designs since the early 1990s, a fraction of the existing stock still includes natural draft non-condensing boilers, based on RECS 2009 equipment age. Based on these assumptions, DOE determined that 2 percent of hot water gas-fired boilers, 3 percent of steam gas-fired boilers, 2 percent of hot water gas-fired boilers, and 2 percent of steam gas-fired boilers replacement installations require either installing new vent connectors or resizing the vent system.

Stainless Steel Venting

Category III stainless steel venting resists corrosion from acidic condensate that may form in the venting when using near-condensing boilers. DOE considered the additional venting cost associated with stainless steel venting for a fraction of installations between 82 percent AFUE and 86 percent AFUE based on the fraction of models with inducer or forced draft fans. Based on manufacturer installation manuals, some of these boilers are installed using stainless steel venting. DOE assumed that 50 percent of models with inducer or forced draft fans will be installed using stainless steel venting. Table 8C.2.6 shows the fractions used in the analysis.

Table 8C.2.6 Stainless Steel Venting Installation Fractions for Non-Condensing Efficiency Levels

Efficiency, AFUE	Gas-fired Hot Water Boiler	Gas-fired Steam Boiler	Oil-fired Hot Water Boiler	Oil-fired Steam Boiler
80%	NA	0%	NA	NA
82%	11%	3%	NA	9%
83%	18%	6%	NA	NA
84%	18%	NA	15%	9%
85%	32%	NA	26%	11%
86%	NA	NA	32%	11%

Table 8C.2.7 presents the average cost of installing stainless steel venting in replacement installations. Stainless steel venting costs include both horizontal and vertical vent installations depending on the shortest vent length.

Table 8C.2.7 Stainless Steel Venting Installation Cost for Non-Condensing Efficiency Levels

Product Class	EL	Stainless Steel Vent Cost *2014$*
Gas-Fired Hot Water Boilers	82% AFUE - Baseline	$533
	83% AFUE - Increased HX Area	$529
	84% AFUE - Increased HX Area	$529
	85% AFUE - Increased HX Area	$529
Gas-Fired Steam Boilers	80% AFUE - Baseline	---
	82% AFUE - Increased HX Area	$554
	83% AFUE - Max Tech	$552
Oil-Fired Hot Water Boilers	84% AFUE - Baseline	$626
	85% AFUE - Increased HX Area	$624
	86% AFUE - Increased HX Area	$621
Oil-Fired Steam Boilers	82% AFUE - Baseline	$631
	84% AFUE - Increased HX Area	$631
	85% AFUE - Increased HX Area	$632
	86% AFUE - Max Tech	$632

Table 8C.2.8 presents the average venting component costs for non-condensing boilers. These costs are only included when applicable.

Table 8C.2.8 Non-Condensing to Non-Condensing Replacement Installation: Average Venting Cost Components (2014$)

Product Class	EL	Vent Resizing	Vent Connector	Chimney Relining	New Stainless Steel Vent
Gas-Fired Hot Water Boilers	82% AFUE - Baseline	$1,495	$277	$1,596	$533
	83% AFUE - Increased HX Area	$1,505	$278	$1,601	$529
	84% AFUE - Increased HX Area	$1,505	$278	$1,601	$529
	85% AFUE - Increased HX Area	$1,433	$279	$1,586	$529
Gas-Fired Steam Boilers	80% AFUE - Baseline	$1,565	$283	$1,606	---
	82% AFUE - Increased HX Area	$1,565	$283	$1,607	$554
	83% AFUE - Max Tech	$1,565	$283	$1,605	$552
Oil-Fired Hot Water Boilers	84% AFUE - Baseline	$2,229	$339	$2,146	$626
	85% AFUE - Increased HX Area	$2,203	$341	$2,145	$624
	86% AFUE - Increased HX Area	$2,294	$340	$2,144	$621
Oil-Fired Steam Boilers	82% AFUE - Baseline	$2,037	$333	$2,134	$631
	84% AFUE - Increased HX Area	$2,037	$333	$2,134	$631
	85% AFUE - Increased HX Area	$2,030	$334	$2,133	$632
	86% AFUE - Max Tech	$2,030	$334	$2,133	$632

8C.2.4.3.2 Non-Condensing to Condensing Boiler Installations

The condensing efficiency levels that DOE considered in the analysis represent condensing boiler designs at 90 percent AFUE or greater. DOE assumed that the venting requirements would be the same when replacing an existing non-condensing or condensing boiler with a condensing boiler.

DOE estimated that nationally in 2021, a growing number of replacement installations would be from non-condensing to condensing boilers. The next four sections explain the changes to the venting systems that would be required when installing condensing boilers and provide information about the fractions of impacted installations. The sections address the following four installation issues:

- condensing flue vent (plastic vent);
- combustion air vent;
- concealing vents in indoor installations; and
- installation with orphaned water heaters.

Condensing Flue Vent (Plastic Vent)

When replacing an existing non-condensing boiler with a condensing boiler, the existing metal vent is replaced with a plastic flue vent (either 2" or 3" polyvinyl chloride (PVC), Polypropylene (PP), or chlorinated polyvinyl chloride (CPVC)). See section 8C.2.4.1 for a description of plastic venting.The installation cost of the replacement condensing boiler flue vent takes into account the following to determine the vent length (see also section 8C.2.4.2):

- boiler installation location;
- house ceiling height and number of floors (determined for each boiler household in the sample); and
- boiler distance from wall or roof, and whether to install a vertical vent (through the roof) or a horizontal vent (through the wall). DOE assumed that the household would install the vent direction with the shortest vent length.

In addition, DOE used the wall type to determine the cost of penetrating the wall for horizontal vent installations.

Combustion Air Vent (Plastic Vent)

A fraction of the condensing boiler installations are direct-vent installations, which use combustion air supplied from the outdoor air. For each household or building in the sample, DOE considered the following factors when calculating the installation cost of the combustion air vent for condensing boilers in the replacement market:

- vent length, which is the same as flue pipe length; and
- vent installation fraction, which depends on the installation location.

Table 8C.2.9 shows the fraction of direct vent installations by installation location, based on a consultant report.

Table 8C.2.9 Fraction of Direct Vent Condensing Boiler Installations

ID	Installation Location	Fraction of Direct Vent Installations
1	Basement (Conditioned)	50%
2	Basement (Unconditioned)	50%
4	Garage	90%
5	Indoor (Closet, Alcove, Utility Room)	67%

Concealing Vent Pipes

For a fraction of indoor installations, DOE added an installation cost to conceal the plastic vent pipes—putting in place structures to mask vents that pass through the living space.

DOE assumed that half of the indoor horizontally vented condensing boiler installations would require such modifications.

Orphaned Water Heaters–Chimney Relining and Vent Resizing

When a condensing boiler replaces an existing non-condensing gas boiler that is commonly vented with a gas water heater, the water heater after the installation becomes "orphaned". Many of these "orphaned water heaters" require venting modifications to meet safety requirements. Such modifications include upgrading the vent connector, resizing metal vents, or relining a masonry chimney. DOE assumed that 100 percent of venting systems with an existing natural draft boiler would need to have the vent connectors replaced for the orphaned water heater, while an additional 40 percent would need to have the entire venting system of the orphaned water heater resized or upgraded. DOE assumed that all orphaned water heater chimneys would need to be relined if built before 1990 and if the existing boiler is a natural draft boiler. DOE also assumed that 20 percent of venting systems with an existing fan-assisted non-condensing boiler would need to have the entire vent of the orphaned water heater resized or upgraded.

Table 8C.2.10 summarizes the four different scenarios that might be encountered in such replacement installations.

Table 8C.2.10 Non-Condensing to Condensing Venting Issues

Existing Non-Condensing Boiler	Replacement	Installation Requirement	Frequency of Applying Requirements
Natural Draft	Condensing	Convert water heater from single wall to Type B vent connector	100%
Natural Draft	Condensing	Resizing orphaned water heater chimney or upgrading metal vent	50%
Natural Draft	Condensing	Reline all unlined chimneys for orphaned water heater	100%
Fan-Assisted	Condensing	Resizing orphaned water heater chimney or upgrading metal vent	10%

Table 8C.2.11 presents the average venting cost components for such replacement installations. These costs are only included when applicable. The table provides the fraction of installations impacted and the average cost. The weighted-average installation cost in the last row is the sum product of the fraction and corresponding average cost.

Table 8C.2.11 Non-Condensing to Condensing Fractions and Average Boiler Installation Venting Costs

Installation Cost Components	Gas-Fired Hot Water Boilers		Oil-Fired Hot Water Boilers	
	Fraction of Installations	Average Cost (2014$)	Fraction of Installations	Average Cost (2014$)
Flue Vent (Plastic)	100%	$431	100%	$437
Combustion Vent	58%	$322	54%	$357
Concealing Vent	15%	$424	9%	$434
Chimney Relining for Orphaned Water Heater	2.4%	$840	1.0%	$883
Vent Resizing for Orphaned Water Heater	0.6%	$784	0.2%	$918
Vent Connector for Orphaned Water Heater	3.5%	$132	1.8%	$139
Weighted Average Installation Cost		$776		$729

8C.2.4.4 New Construction Installations

For boiler installations in new construction (including new owners for hot water gas-fired boilers), DOE accounted for the installation cost of a new venting system for both non-condensing boilers and condensing boilers.

DOE also accounted for the installation costs of commonly vented boilers (together with a water heater) in the new construction cases. When a commonly vented non-condensing boiler and water heater are installed, the venting cost is equally divided between the two appliances. In the condensing boiler installations with isolated water heater, DOE added half of the water heater venting system installation cost to the venting installation cost of the condensing boiler.

Table 8C.2.12 presents the average venting cost components for non-condensing new construction installations. For systems that require stainless steel, the total venting cost is the sum of the two columns. Table 8C.2.13 presents the average venting cost components for condensing boiler in new construction and new owner installations. These costs are only included when applicable.

Table 8C.2.12 New Construction and New Owner Non-Condensing Venting Cost Components (2014$)

Product Class	EL	Metal Vent System Cost	Stainless Steel Cost
Gas-Fired Hot Water Boilers	82% AFUE - Baseline	$1,731	$544
	83% AFUE - Increased HX Area	$1,732	$541
	84% AFUE - Increased HX Area	$1,732	$541
	85% AFUE - Increased HX Area	$1,735	$541
Oil-Fired Hot Water Boilers	84% AFUE - Baseline	$2,259	$805
	85% AFUE - Increased HX Area	$2,152	$784
	86% AFUE - Increased HX Area	$2,161	$776

Table 8C.2.13 New Construction and New Owner Condensing Venting Cost Components (2014$)

Installation Cost Components	Gas-Fired Hot Water Boilers	Oil-Fired Hot Water Boilers
Flue Vent	$394	$374
Combustion Vent	$290	$300
Concealing Vent	$378	$393

8C.2.5 Condensate Removal for Condensing Boilers

Condensate removal is required for all condensing boiler installations in both replacement and new construction cases. DOE considered the following when assessing the cost of condensate removal:

- *Condensate Pipe:* For condensing boilers, excess condensate must be deposited in a drain. Therefore, for all installations DOE applied the cost of adding condensate pipe (on average 15 feet).
- *Condensate Pump:* If a drain is not near, then the condensate must be pumped to a remote drain. If a central air-conditioner is present, then DOE assumes that already there is either a drain nearby or a pump already exists to remove the condensate from the air conditioner during the cooling season. DOE assumes that a condensate pump is required for half of the installations without a central air conditioner.
- *Condensate Neutralizer:* DOE assumed that 12.5 percent of all installations would require a condensate neutralizer.
- *Additional Electrical Outlet:* DOE assumed that half of all installations would require an additional electricity outlet. DOE included this additional cost.

Table 8C.2.14 summarizes the condensate removal adders associated with condensing boilers.

Table 8C.2.14 Installation Fractions for Condensate Removal

Installation Cost Description	Criteria	Frequency of applying criteria
Condensate Pipe	All installations	100%
Condensate Pump	Installations without AC	25%
Condensate Neutralizer	All installations	12.5%
Electrical Outlet (additional)	Installations requiring a Pump	50%

In addition to the installation costs, the electricity use of the pump is taken into account (60 watts for the condensate pump) in the energy use calculations (see chapter 7).

Table 8C.2.15 presents the average costs for condensate removal components for replacement and new owner installations. Table 8C.2.16 presents the average costs for condensate removal components for new construction installations. These costs are only included when applicable.

Table 8C.2.15 Installation Cost Components for Condensate Removal, Replacement (2014$)

Installation Cost Components	Gas-Fired Hot Water Boilers	Oil-Fired Hot Water Boilers
Electrical Connection	$181	$178
Condensate Pump	$268	$266
Condensate Pipe	$19	$18
Condensate Neutralizer	$117	$116

Table 8C.2.16 Installation Cost Components for Condensate Removal, New Construction and New Owners (2014$)

Installation Cost Components	Gas-Fired Hot Water Boilers	Oil-Fired Hot Water Boilers
Condensate Pipe	$18	$17
Condensate Neutralizer	$115	$104

8C.2.6 Summary of Installation Costs

Table 8C.2.17 presents the average installation costs for all residential boiler product classes disaggregated by the three main installation components (*i.e.*, basic costs, venting costs, and condensate withdrawal costs).

Table 8C.2.17 Summary of Installation Costs

EL	Design Option	Basic Costs (2014$)	Venting Costs (2014$)	Condensate Withdrawal Costs (2014$)	Total (2014$)
Gas-fired Hot Water Boiler					
0	82% AFUE – Baseline	$2,741	$560	$0	$3,301
1	83% AFUE – Increased HX Area	$2,741	$561	$0	$3,302
2	84% AFUE – Increased HX Area	$2,741	$561	$0	$3,302
3	85% AFUE – Increased HX Area	$2,741	$554	$0	$3,295
4	90% AFUE – Condensing Baseline	$2,741	$746	$112	$3,599
5	92% AFUE – Increased HX Area	$2,741	$746	$112	$3,599
6	96% AFUE – Max Tech	$2,741	$746	$112	$3,599
Gas-fired Steam Boiler					
0	80% AFUE – Baseline	$2,917	$120	$0	$3,037
1	82% AFUE – Increased HX Area	$2,917	$133	$0	$3,050
2	83% AFUE – Max Tech	$2,917	$144	$0	$3,061
Oil-fired Hot Water Boiler					
0	84% AFUE – Baseline	$2,818	$251	$0	$3,069
1	85% AFUE – Increased HX Area	$2,818	$303	$0	$3,121
2	86% AFUE – Increased HX Area	$2,818	$329	$0	$3,147
3	91% AFUE – Max Tech	$2,818	$726	$118	$3,662
Oil-fired Steam Boiler					
0	82% AFUE – Baseline	$2,894	$180	$0	$3,074
1	84% AFUE – Increased HX Area	$2,894	$180	$0	$3,074
2	85% AFUE – Increased HX Area	$2,894	$187	$0	$3,081
3	86% AFUE – Max Tech	$2,894	$187	$0	$3,081

8C.3 RS MEANS 2015 REGIONAL LABOR COSTS

DOE used regional material and labor costs to more accurately estimate installation, maintenance, and repair costs by region. RS Means provides average national labor costs for different trade groups as shown in Table 8C.3.1. Bare costs are given in RS Means, while labor costs including overhead and profit (O&P) are the bare costs multiplied by the RS Means markups by trade shown in Table 8C.3.2.

Table 8C.3.1 RS Means 2015 National Average Labor Costs by Crew (2014$)

Crew Type	Crew Description	Laborers per Crew	Cost per Labor-Hour	
			Bare Costs	Incl. O&P*
Residential Labors Costs				
Q1	1 Plumber, 1 Plumber Apprentice	2	$34.85	$57.50
Q9	1 sheet metal worker, 1 sheet metal worker apprentice	2	$35.47	$58.53
Q10	2 sheet metal worker, 1 sheet metal worker apprentice	3	$33.19	$55.43
1 Plum	1 Plumbers	1	$34.45	$57.48
1 Plum Apprentice	1 Plumber Apprentice	1	$38.72	$63.89
1 Elec	1 Electrician	1	$30.97	$51.10
1 Sheet	1 Sheet metal worker	1	$36.62	$60.00
1 Sheet Apprentice	1 Sheet metal worker apprentice	1	$39.42	$65.04
1 Carp	1 Carpenter	1	$31.52	$52.00
Commercial Labors Costs (Standard Union)				
Q1	1 Plumber, 1 Plumber Apprentice	2	$29.52	$49.26
Q9	1 sheet metal worker, 1 sheet metal worker apprentice	2	$32.82	$55.10
Q10	2 sheet metal worker, 1 sheet metal worker apprentice	3		
1 Plum	1 Plumbers	1	$52.78	$79.71
1 Plum Apprentice	1 Plumber Apprentice	1	$56.84	$85.82
1 Elec	1 Electrician	1	$50.31	$76.88
1 Sheet	1 Sheet metal worker	1	$52.17	$79.73
1 Sheet Apprentice	1 Sheet metal worker apprentice	1	$58.65	$88.57
1 Carp	1 Carpenter	1	$46.91	$70.84

* O&P includes markups in Table 8C.3.2

Table 8C.3.2 RS Means Labor Costs Markups by Trade (Residential)

Trade	Workers Comp.	Aver Fixed Overhead	Overhead	Profit	Total
Plumber	7.0%	18.0%	16.0%	10.0%	51.0%
Electrician	5.8%	18.0%	16.0%	10.0%	49.8%
Sheet Metal	8.8%	18.0%	16.0%	10.0%	52.8%
Carpenter	14.9%	18.0%	11.0%	10.0%	53.9%

RS Means also provides material and labor cost factors for 295 cities and towns in the U.S. To derive average labor cost values by state, DOE weighted the price factors by 2008-2012 boiler shipments by state. DOE used the material and labor cost factors for cost associated with fire suppression, plumbing, and HVAC. Table 8C.3.3 shows the final regional material and labor price factors used in the analysis by geographical area and Table 8C.3.4 by census division.

Table 8C.3.3 Material and Labor Cost Factors by Geographical Area (for RECS 2009 Sample)

Geographical Area	Plumbing, HVAC		Electrical		Weighted Average	
	Material	Labor	Material	Labor	Material	Labor
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	0.99	0.90	1.01	0.90	1.00	0.95
Massachusetts	1.00	1.19	1.02	1.16	1.01	1.27
New York	1.00	1.61	1.02	1.68	1.03	1.60
New Jersey	1.00	1.25	1.02	1.37	1.00	1.24
Pennsylvania	0.98	1.14	0.96	1.25	0.98	1.16
Illinois	0.99	1.28	0.95	1.27	0.99	1.32
Indiana, Ohio	0.99	0.89	0.98	0.90	0.98	0.90
Michigan	1.00	1.01	0.97	0.99	0.96	1.01
Wisconsin	0.99	0.95	1.02	0.95	1.00	1.01
Iowa, Minnesota, North Dakota, South Dakota	0.99	0.97	1.01	0.94	1.00	1.00
Kansas, Nebraska	0.99	0.74	0.99	0.77	0.99	0.74
Missouri	0.99	0.96	1.01	0.95	0.99	0.98
Virginia	0.99	0.66	0.97	0.71	1.01	0.69
Delaware, District of Columbia, Maryland	0.98	0.84	0.98	0.95	0.99	0.84
Georgia	0.99	0.66	0.99	0.69	0.97	0.67
North Carolina, South Carolina	1.00	0.36	0.97	0.44	0.99	0.48
Florida	1.00	0.69	0.99	0.68	1.00	0.73
Alabama, Kentucky, Mississippi	0.99	0.75	0.99	0.78	0.97	0.80
Tennessee	1.00	0.71	1.00	0.63	0.98	0.68
Arkansas, Louisiana, Oklahoma	1.00	0.59	1.02	0.65	0.99	0.62
Texas	0.99	0.56	0.95	0.61	0.98	0.61
Colorado	0.99	0.79	1.01	0.84	1.01	0.82
Idaho, Montana, Utah, Wyoming	1.00	0.70	0.98	0.70	1.01	0.71
Arizona	1.00	0.80	0.98	0.66	0.97	0.74
Nevada, New Mexico	1.00	0.76	0.91	0.80	0.99	0.80
California	0.99	1.21	1.00	1.21	1.01	1.19
Oregon, Washington	1.00	1.04	1.02	0.97	1.02	0.98
Alaska	1.00	1.05	1.34	1.17	1.24	1.14
Hawaii	1.00	1.10	1.06	1.27	1.12	1.21
West Virginia	0.98	0.85	0.96	0.90	0.99	0.88

Table 8C.3.4 Material and Labor Cost Factors by Census Division (for CBECS 2003 Sample)

Census Division	Plumbing, HVAC		Electrical		Weighted Average	
	Material	Labor	Material	Labor	Material	Labor
New England	0.99	1.02	1.01	1.01	1.00	1.08
Middle Atlantic	0.99	1.43	1.01	1.51	1.01	1.42
East North Central	0.99	1.06	0.98	1.05	0.98	1.09
West North Central	0.99	0.96	1.01	0.93	1.00	0.99
South Atlantic	0.98	0.79	0.97	0.88	0.99	0.80
East South Central	1.00	0.73	0.99	0.70	0.97	0.74
West South Central	1.00	0.58	0.99	0.63	0.99	0.62
Mountain	1.00	0.76	0.99	0.79	1.01	0.79

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APPENDIX 8D. ENERGY PRICE CALCULATIONS FOR RESIDENTIAL BOILERS

8D.1 INTRODUCTION

Figure 8D.1.1 depicts the energy price calculation process, which also encompasses average energy price, seasonal marginal price factor, and monthly price factor calculations.

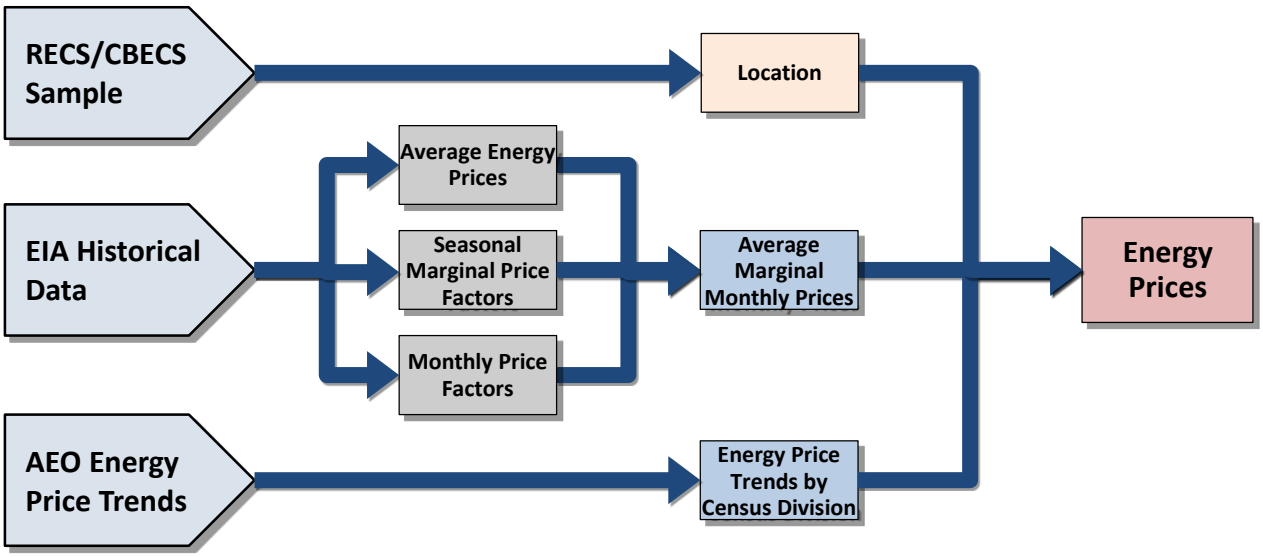

Figure 8D.1.1 Energy Price Calculation Process

8D.2 RECS/CBECS SAMPLE MAPPING PROCESS

To match the state data from the Energy Information Administration (EIA) to the Residential Energy Consumption Survey (RECS) 2009[1] household and Commercial Building Energy Consumption Survey (CBECS) 2003[2] building samples, DOE used the average 2008-2012 fraction of boiler shipments by state.[3] RECS 2009 utilizes 27 regions (also called reportable domains) and CBECS 2003 provides nine census divisions. The 27th RECS region includes Oregon, Washington, Alaska, and Hawaii. DOE subdivided Alaska and Hawaii into separate regions (28 and 29, respectively), based on cooling and heating degree days. In addition, West Virginia, which is in RECS region 14, was disaggregated into region 30 based on cooling and heating degree days.

8D.3 AVERAGE MARGINAL MONTHLY PRICES

8D.3.1 Average Annual Prices Determination

8D.3.1.1 Annual Electrical Prices

DOE derived 2013 annual electricity prices from EIA Form 826 data.[4] The EIA Form

826 data include energy prices by State. Table 8D.3.1 shows the monthly residential electricity prices for each state. Table 8D.3.2 shows the monthly commercial electricity prices for each state. DOE calculated both commercial and residential annual electricity prices for each State by averaging monthly energy prices by State. Note that all energy prices were converted from 2013$ to 2014$ in the LCC spreadsheet using the consumer price index (CPI). [a]

Table 8D.3.1 2013 Monthly Residential Electricity Prices by State (2013¢/kWh)

State	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg. 2013
United States	11.45	11.63	11.61	11.92	12.41	12.54	12.65	12.52	12.51	12.36	12.09	11.72	12.12
Alabama	10.81	10.91	10.96	11.39	11.42	11.65	11.56	11.60	11.73	11.79	10.74	10.50	11.26
Alaska	17.12	17.50	17.88	18.45	18.45	18.44	19.20	18.62	18.40	17.86	18.27	18.04	18.19
Arizona	10.25	10.69	10.87	11.73	12.16	12.15	12.47	12.28	12.17	12.01	11.02	10.97	11.56
Arkansas	8.80	9.08	9.14	9.45	9.95	10.14	10.03	10.06	10.08	9.63	9.75	8.98	9.59
California	16.06	15.37	15.15	15.19	16.03	17.16	16.91	16.23	16.90	16.09	16.44	16.12	16.14
Colorado	11.11	11.32	11.42	11.64	11.65	12.49	12.87	12.63	12.65	11.84	11.66	11.46	11.90
Connecticut	17.01	16.93	17.20	17.38	18.07	17.73	17.28	17.54	17.89	18.57	18.18	17.59	17.61
Delaware	12.80	12.64	12.96	13.32	14.21	13.12	12.23	12.61	12.78	13.98	13.36	12.64	13.05
District of Columbia	12.06	11.97	12.14	12.36	12.52	12.65	12.89	12.98	12.79	13.07	12.88	12.50	12.57
Florida	11.20	11.28	11.09	11.05	11.22	11.20	11.27	11.26	11.58	11.25	11.47	11.31	11.27
Georgia	10.43	10.60	10.84	11.02	11.74	12.39	12.55	12.59	12.20	11.24	10.66	10.41	11.39
Hawaii	37.86	36.58	37.43	36.96	37.11	37.03	36.61	36.79	36.28	37.27	37.24	36.58	36.98
Idaho	8.65	8.61	8.53	8.73	8.88	10.15	10.47	10.23	9.47	9.89	9.51	9.26	9.37
Illinois	10.42	10.85	10.46	10.92	11.89	10.57	10.44	10.73	10.09	11.22	10.61	9.84	10.67
Indiana	10.13	10.34	10.63	11.53	11.66	11.32	11.23	11.23	11.28	11.69	11.18	10.49	11.06
Iowa	10.03	10.07	10.38	10.68	10.99	11.93	12.11	12.31	11.76	11.59	10.78	10.33	11.08
Kansas	10.70	11.31	11.25	11.64	12.12	12.19	12.16	12.15	11.84	11.72	11.49	10.92	11.62
Kentucky	9.33	9.50	9.41	9.96	10.24	10.13	10.14	9.96	10.04	9.92	9.68	9.52	9.82
Louisiana	8.88	9.17	9.19	9.17	9.70	9.70	9.78	9.76	9.72	9.68	9.19	8.76	9.39
Maine	14.46	14.60	14.20	14.21	14.37	14.17	14.27	14.39	14.46	14.45	14.39	14.31	14.36
Maryland	12.50	12.51	12.56	12.78	12.89	13.98	13.73	13.92	13.94	13.69	13.16	13.43	13.26
Massachusetts	14.35	14.93	14.84	15.06	15.82	15.92	15.20	16.03	15.94	15.74	16.14	20.00	15.83
Michigan	13.65	13.84	14.08	14.37	15.11	15.47	15.06	14.98	14.98	14.99	14.59	14.20	14.61
Minnesota	11.01	11.16	11.20	11.45	12.02	12.71	12.67	12.63	12.47	12.07	11.52	11.20	11.84
Mississippi	9.93	10.34	10.49	11.27	11.45	11.10	10.84	10.77	10.79	10.93	11.28	10.54	10.81
Missouri	9.02	9.45	9.64	9.85	11.75	12.41	12.55	12.37	10.94	10.23	9.88	9.18	10.61
Montana	9.77	9.82	10.00	10.11	10.40	11.00	10.98	10.88	11.02	10.65	10.23	9.94	10.40
Nebraska	8.73	9.28	9.43	9.67	10.13	11.69	12.00	11.93	11.85	10.48	9.93	9.18	10.36
Nevada	11.24	11.59	11.90	12.28	11.96	11.56	11.60	11.76	11.95	12.99	13.06	12.30	12.02
New Hampshire	16.02	16.32	16.58	16.60	16.90	16.68	16.06	15.88	16.08	16.75	16.38	16.13	16.37
New Jersey	15.30	15.26	15.33	15.45	15.56	16.04	16.43	16.24	16.07	15.56	15.34	15.28	15.66
New Mexico	10.88	11.20	11.31	11.34	11.40	12.47	12.76	12.63	12.02	11.65	11.04	10.84	11.63
New York	17.93	19.10	18.16	17.67	18.35	19.32	20.03	19.14	19.56	18.88	18.49	18.18	18.73
North Carolina	10.24	10.51	10.35	11.10	11.27	11.11	11.24	11.41	11.56	11.86	10.99	10.56	11.02
North Dakota	7.72	8.26	8.41	8.63	9.64	10.89	10.28	10.88	10.66	9.72	8.90	8.56	9.38
Ohio	11.11	11.12	11.39	11.79	12.49	13.06	12.98	12.83	12.33	12.09	11.97	11.30	12.04
Oklahoma	8.05	9.19	9.41	10.36	10.48	10.25	9.85	9.96	10.63	10.64	9.66	8.20	9.72
Oregon	9.62	9.70	9.65	9.69	9.91	10.11	10.18	10.15	10.09	10.10	9.97	9.92	9.92

[a] www.bls.gov/cpi/

State	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg. 2013
Pennsylvania	12.32	12.25	12.24	12.56	12.89	13.06	13.11	13.25	13.31	13.11	12.95	12.75	12.82
Rhode Island	14.48	16.15	15.91	14.09	14.55	13.68	13.05	15.42	15.52	14.26	15.65	20.17	15.24
South Carolina	11.72	11.60	11.11	12.04	12.71	12.21	12.30	12.21	12.11	12.44	12.01	11.68	12.01
South Dakota	9.29	9.48	9.60	9.76	10.65	11.28	11.19	11.35	11.16	10.89	10.07	9.66	10.37
Tennessee	9.98	9.61	9.73	9.82	10.32	10.40	10.35	10.17	9.83	9.87	9.95	9.79	9.99
Texas	10.84	11.05	11.03	11.43	11.57	11.44	11.41	11.45	11.36	11.68	11.67	11.27	11.35
Utah	9.64	9.68	9.74	9.83	10.44	10.77	11.33	11.17	10.92	10.09	10.04	9.98	10.30
Vermont	16.49	16.34	16.55	17.60	17.76	17.76	17.21	17.07	17.27	17.64	17.52	17.03	17.19
Virginia	9.92	10.24	10.42	10.54	11.21	11.42	11.49	11.49	11.50	11.12	10.92	10.36	10.89
Washington	8.50	8.53	8.51	8.59	8.69	8.85	8.90	8.96	9.00	8.84	8.73	8.66	8.73
West Virginia	9.38	9.44	9.48	9.67	10.04	9.74	9.61	9.73	9.64	9.60	9.36	9.08	9.56
Wisconsin	12.96	13.11	13.18	13.44	13.73	14.09	14.00	14.27	14.07	13.76	13.47	12.79	13.57
Wyoming	9.50	9.55	9.81	9.92	10.20	10.75	10.83	10.68	10.72	10.56	10.23	10.11	10.24

Table 8D.3.2 2013 Monthly Commercial Electricity Prices by State (2013¢/kWh)

State	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg. 2013
United States	9.77	10.06	10.02	9.96	10.25	10.69	10.75	10.72	10.56	10.31	10.08	9.96	10.26
Alabama	10.34	10.41	10.41	10.31	10.45	10.87	10.58	10.68	10.57	10.66	10.45	10.29	10.50
Alaska	14.40	14.75	14.93	15.80	15.71	15.71	15.79	15.41	15.48	15.95	16.40	16.70	15.59
Arizona	9.05	9.34	9.38	9.58	10.15	10.38	10.50	10.39	10.23	9.93	9.22	9.17	9.78
Arkansas	7.88	7.94	7.87	7.98	8.12	8.28	8.25	8.21	8.15	7.90	7.85	7.96	8.03
California	11.58	12.48	12.28	12.54	13.85	16.57	16.36	16.45	15.90	14.70	14.01	12.25	14.08
Colorado	9.11	9.45	9.52	9.48	9.77	10.50	10.29	10.40	10.26	10.06	9.76	9.50	9.84
Connecticut	14.55	15.28	14.90	14.58	14.55	14.68	14.36	14.28	14.48	14.63	14.73	14.73	14.65
Delaware	10.00	10.20	10.23	10.37	10.50	10.16	9.88	10.24	10.01	10.11	10.32	10.44	10.21
District of Columbia	11.97	11.88	11.86	11.82	11.87	11.77	12.02	11.94	11.96	12.15	12.14	11.93	11.94
Florida	9.42	9.61	9.58	9.31	9.34	9.25	9.26	9.23	9.39	9.37	9.61	9.44	9.40
Georgia	9.58	9.79	10.00	9.83	9.97	10.41	10.18	10.16	10.03	9.80	10.02	9.92	9.97
Hawaii	35.79	34.18	34.69	34.72	33.84	33.60	33.06	33.58	32.95	34.30	34.60	33.68	34.08
Idaho	6.71	6.81	6.90	7.07	7.10	7.94	7.95	7.74	7.55	7.66	7.51	7.37	7.36
Illinois	7.83	8.12	8.08	8.21	8.68	8.03	8.25	8.42	8.01	8.26	8.04	7.80	8.14
Indiana	9.39	9.39	9.68	9.80	9.63	9.57	9.53	9.61	9.64	9.78	9.71	9.51	9.60
Iowa	7.86	7.95	7.98	8.06	8.19	8.95	9.31	9.44	8.76	8.50	8.02	8.02	8.42
Kansas	9.14	9.62	9.60	9.58	9.93	10.05	10.02	9.97	9.74	9.61	9.35	9.32	9.66
Kentucky	8.77	8.76	8.97	8.99	9.13	8.08	8.00	7.96	8.42	8.82	8.81	8.86	8.63
Louisiana	8.85	9.09	9.14	8.83	9.04	8.98	9.08	9.07	8.91	8.96	8.79	8.81	8.96
Maine	12.07	12.71	11.97	11.54	11.25	11.04	11.57	11.34	11.42	11.41	11.71	12.98	11.75
Maryland	10.29	10.38	10.25	10.22	10.35	10.90	10.85	11.18	11.06	11.03	10.74	10.82	10.67
Massachusetts	13.68	14.86	14.81	13.50	13.41	14.20	14.19	14.16	13.93	13.65	13.93	16.42	14.23
Michigan	10.45	10.84	10.95	10.84	11.41	11.56	11.45	11.45	10.97	11.09	10.88	10.72	11.05
Minnesota	8.72	9.02	8.95	9.03	9.63	10.31	10.03	10.01	9.89	9.27	9.11	8.92	9.41
Mississippi	9.48	9.70	9.96	10.32	10.17	10.23	10.23	10.04	10.08	10.17	10.23	10.54	10.10
Missouri	7.62	7.97	8.06	8.07	9.47	10.34	10.38	10.41	8.96	8.04	7.91	7.66	8.74
Montana	9.24	9.29	9.48	9.55	9.67	9.79	9.72	9.47	9.58	9.60	9.62	9.46	9.54
Nebraska	7.92	8.24	8.34	8.22	8.55	9.06	9.37	9.12	9.17	8.55	8.27	8.18	8.58
Nevada	8.43	8.62	8.62	8.94	8.76	8.51	9.02	9.16	9.31	9.79	9.66	9.43	9.02
New Hampshire	13.67	14.04	13.80	13.45	13.39	13.51	13.30	13.03	13.10	13.32	13.45	14.30	13.53
New Jersey	12.09	11.94	12.06	12.17	12.68	13.74	13.76	13.82	13.46	12.47	12.26	12.23	12.72
New Mexico	9.04	9.35	9.48	9.01	9.55	10.27	10.62	10.81	9.95	9.56	9.30	9.34	9.69

State	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg. 2013
New York	14.83	15.70	14.88	14.12	14.54	16.05	16.75	16.38	16.62	15.36	13.76	14.45	15.29
North Carolina	8.43	8.69	8.55	8.58	8.44	8.76	9.08	9.01	8.90	9.02	8.63	8.86	8.75
North Dakota	7.51	8.02	8.05	8.01	8.55	9.13	8.59	9.13	9.00	8.63	8.15	8.26	8.42
Ohio	9.20	9.18	9.37	9.49	9.42	9.55	9.39	9.45	9.40	9.33	9.32	9.06	9.35
Oklahoma	6.81	7.08	7.46	7.61	7.73	8.36	8.42	8.20	8.45	7.98	7.10	7.35	7.71
Oregon	8.49	8.69	8.68	8.72	8.72	8.73	8.64	8.55	8.65	8.95	8.80	8.57	8.68
Pennsylvania	9.32	9.18	9.33	9.38	9.42	9.16	9.25	9.28	9.23	9.12	9.16	9.19	9.25
Rhode Island	12.42	14.92	13.95	11.73	12.06	12.20	11.31	12.51	12.80	11.77	13.21	16.83	12.98
South Carolina	9.55	9.84	9.82	9.48	9.64	10.30	10.08	9.89	10.14	9.58	10.09	9.97	9.87
South Dakota	7.97	8.17	8.19	8.18	8.61	8.84	8.98	8.98	8.86	8.64	8.44	8.25	8.51
Tennessee	10.22	9.73	10.11	9.85	9.95	10.34	10.25	10.22	9.97	9.64	9.72	9.82	9.99
Texas	8.02	8.03	8.07	8.06	8.19	8.09	8.06	7.98	7.84	8.00	7.90	8.00	8.02
Utah	7.53	7.80	7.93	7.97	8.81	9.16	8.49	8.56	8.99	8.67	7.98	7.65	8.30
Vermont	14.33	13.95	14.20	15.18	15.21	14.84	14.46	14.48	14.65	15.02	14.84	14.85	14.67
Virginia	7.82	7.92	7.84	7.88	7.94	8.06	8.10	8.08	8.16	8.14	8.16	7.86	8.00
Washington	7.75	7.84	7.84	7.74	7.69	7.65	7.74	7.67	7.72	7.82	7.97	7.91	7.78
West Virginia	8.20	8.48	8.20	8.60	8.58	8.01	7.87	8.18	8.05	7.99	8.21	7.75	8.18
Wisconsin	10.32	10.68	10.46	10.62	10.75	11.01	11.16	11.34	11.04	10.79	10.62	10.05	10.74
Wyoming	8.05	8.36	8.40	8.57	8.77	8.75	8.56	8.60	8.72	9.12	8.73	8.37	8.58

Table 8D.3.3 shows the shipment-weighted average residential electricity prices for each RECS geographic area. Table 8D.3.4 shows the shipment-weighted average commercial electricity prices for each CBECS geographic area. For the 30 RECS 2009 regions or nine CBECS census divisions with more than one State, DOE weighted each State's average price by the average 2008-2012 fraction of boiler shipments by state.[3]

Table 8D.3.3 Average Residential Electricity Prices by RECS 2009 Region in 2013

ID	Geographic Area	2014$/kWh
1	Connecticut, Maine, New Hampshire, Rhode Island, Vermont	$0.168
2	Massachusetts	$0.161
3	New York	$0.190
4	New Jersey	$0.159
5	Pennsylvania	$0.130
6	Illinois	$0.108
7	Indiana, Ohio	$0.120
8	Michigan	$0.148
9	Wisconsin	$0.138
10	Iowa, Minnesota, North Dakota, South Dakota	$0.116
11	Kansas, Nebraska	$0.111
12	Missouri	$0.108
13	Virginia	$0.111
14	Delaware, District of Columbia, Maryland	$0.135
15	Georgia	$0.116
16	North Carolina, South Carolina	$0.113
17	Florida	$0.114
18	Alabama, Kentucky, Mississippi	$0.102
19	Tennessee	$0.101
20	Arkansas, Louisiana, Oklahoma	$0.096
21	Texas	$0.115
22	Colorado	$0.121
23	Idaho, Montana, Utah, Wyoming	$0.105
24	Arizona	$0.118
25	Nevada, New Mexico	$0.119
26	California	$0.164
27	Oregon, Washington	$0.090
28	Alaska	$0.185
29	Hawaii	$0.376
30	West Virginia	$0.097
	U.S. Average	$0.123

Table 8D.3.4 Average Commercial Electricity Prices by CBECS 2003 Region in 2013

ID	Geographic Area	2014$/ kWh
1	New England	$0.142
2	Middle Atlantic	$0.136
3	East North Central	$0.098
4	West North Central	$0.091
5	South Atlantic	$0.101
6	East South Central	$0.096
7	West South Central	$0.086
8	Mountain	$0.097
9	Pacific	$0.099
	U.S. Average	$0.104

8D.3.1.2 Annual Natural Gas Prices

DOE obtained the data for natural gas prices from EIA's Natural Gas Navigator,[5] which includes monthly natural gas prices by State for residential, commercial, and industrial customers. Table 8D.3.5 shows the monthly residential natural gas prices for each state. Table 8D.3.6 shows the monthly commercial natural gas prices for each state (in 2013$/thousand cubic feet).

Table 8D.3.5 2013 Monthly Residential Natural Gas Prices by State (2013$/tcf)

State	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg. 2013
United States	9.15	9.24	9.36	10.43	12.61	15.02	16.30	16.43	15.69	12.38	10.05	9.15	12.15
Alabama	14.28	14.13	14.49	15.22	18.19	20.60	21.81	21.41	21.32	20.61	15.94	14.05	17.67
Alaska	9.07	9.18	8.41	8.36	9.00	9.52	9.84	9.27	9.03	8.79	8.19	9.13	8.98
Arizona	11.09	11.86	12.38	16.55	17.75	20.06	21.92	21.91	21.26	17.94	15.24	12.54	16.71
Arkansas	9.33	9.71	9.06	10.07	12.37	15.89	18.17	18.74	18.39	17.14	11.08	9.04	13.25
California	9.50	8.91	9.19	9.83	10.94	11.38	11.06	10.92	10.52	10.42	9.92	10.08	10.22
Colorado	6.76	7.02	7.19	7.58	8.85	11.50	13.63	13.98	12.31	8.71	7.75	6.91	9.35
Connecticut	13.23	12.93	12.27	11.40	13.81	15.70	18.29	19.13	18.18	16.60	13.31	12.48	14.78
Delaware	12.32	12.19	12.38	13.12	16.23	19.65	22.32	24.13	23.50	20.78	14.66	12.46	16.98
District of Columbia	11.44	11.56	11.23	12.69	14.63	15.86	17.18	17.67	17.76	17.27	13.35	11.49	14.34
Florida	15.42	16.30	15.96	16.67	19.76	21.44	22.75	23.38	22.95	22.52	20.20	17.67	19.59
Georgia	12.59	12.27	11.87	14.20	17.34	22.85	24.38	24.49	24.99	20.08	13.39	12.83	17.61
Hawaii	51.66	54.03	54.47	51.53	48.72	46.54	48.35	47.10	45.86	46.92	45.81	47.89	49.07
Idaho	7.78	7.81	8.16	8.10	8.52	8.72	9.09	9.47	8.60	8.41	8.08	8.19	8.41
Illinois	7.00	6.93	7.31	8.93	12.52	14.57	15.62	15.52	14.29	9.65	7.64	7.02	10.58
Indiana	7.57	7.79	7.58	10.38	13.29	16.46	15.30	15.33	15.11	8.46	7.32	7.09	10.97
Iowa	8.04	8.21	8.29	8.79	10.22	13.12	14.92	16.08	16.23	12.23	8.94	7.78	11.07
Kansas	8.69	8.76	8.87	9.98	11.62	17.76	20.29	20.57	20.17	16.10	10.80	8.81	13.54
Kentucky	8.03	8.10	7.87	9.72	13.87	17.58	20.71	21.08	21.08	14.24	10.04	9.11	13.45
Louisiana	9.05	9.71	9.23	10.88	12.71	14.92	15.72	15.97	15.56	15.29	11.98	8.91	12.49
Maine	15.33	15.14	15.67	15.75	15.45	15.59	17.76	18.15	17.29	15.31	13.43	14.17	15.75
Maryland	10.63	10.26	9.95	11.91	15.29	17.29	18.98	18.55	18.83	14.59	11.39	11.25	14.08

State	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg. 2013
Massachusetts	13.22	13.13	13.20	13.38	14.59	14.81	16.22	16.74	15.24	13.38	13.54	13.50	14.25
Michigan	8.68	8.76	8.58	9.28	11.66	12.71	13.71	13.97	12.12	9.52	8.28	8.23	10.46
Minnesota	7.37	7.51	7.58	8.25	10.42	12.29	13.11	13.11	11.65	8.75	8.04	7.75	9.65
Mississippi	8.13	8.26	7.89	8.71	10.22	12.59	13.63	13.70	13.66	12.17	9.59	7.93	10.54
Missouri	8.78	9.08	9.14	10.76	12.87	21.45	24.06	25.14	24.34	19.40	11.79	9.08	15.49
Montana	7.56	7.79	7.73	8.02	9.04	10.30	11.62	11.81	11.17	8.50	7.88	7.72	9.10
Nebraska	7.32	7.28	7.35	7.81	9.10	13.50	15.54	16.61	15.47	12.40	8.74	7.44	10.71
Nevada	7.63	7.87	8.48	10.03	11.09	12.16	13.22	14.39	13.44	11.83	10.57	9.10	10.82
New Hampshire	11.99	11.87	13.06	13.21	14.47	16.46	20.05	21.18	20.84	17.49	14.25	15.17	15.84
New Jersey	10.83	11.03	11.14	10.65	11.83	12.55	13.58	13.90	13.40	12.51	10.45	8.88	11.73
New Mexico	7.56	7.59	7.80	8.94	10.74	13.97	15.33	15.28	14.97	11.88	9.46	8.02	10.96
New York	11.27	10.80	11.41	12.65	15.73	18.16	19.25	18.99	18.42	16.12	12.27	10.50	14.63
North Carolina	10.89	10.03	10.60	12.39	17.15	22.72	21.61	22.05	21.37	16.72	11.03	11.22	15.65
North Dakota	6.49	6.60	6.62	7.10	9.22	12.68	15.60	15.38	12.36	8.36	7.14	6.84	9.53
Ohio	7.61	7.70	7.89	9.12	13.23	17.89	22.78	23.46	21.80	15.40	9.26	7.77	13.66
Oklahoma	7.66	8.38	8.02	9.29	11.83	19.30	23.27	24.11	23.76	19.96	11.05	6.99	14.47
Oregon	9.86	10.67	11.07	11.44	12.40	13.74	14.73	15.53	13.30	11.06	10.41	9.79	12.00
Pennsylvania	10.46	10.35	10.52	11.21	13.77	16.83	19.80	20.21	18.47	15.50	11.59	10.64	14.11
Rhode Island	12.66	13.93	14.68	17.56	18.85	19.41	21.01	21.01	18.92	15.03	12.61	13.32	16.58
South Carolina	11.05	10.08	10.23	13.54	19.27	24.80	25.62	25.15	25.41	19.94	11.53	12.17	17.40
South Dakota	7.46	7.64	7.91	8.01	9.09	11.48	13.18	13.88	13.83	9.83	8.30	7.17	9.82
Tennessee	7.92	8.54	8.41	10.23	11.69	15.79	16.60	16.71	17.32	15.00	9.72	8.24	12.18
Texas	7.70	8.45	8.66	10.58	12.07	17.10	19.74	20.58	20.06	18.51	13.01	8.55	13.75
Utah	8.10	8.07	8.32	8.46	8.12	9.82	10.81	10.83	10.85	8.90	8.70	8.71	9.14
Vermont	14.73	14.78	15.10	15.61	17.74	20.00	22.97	23.69	22.61	19.87	15.10	13.81	18.00
Virginia	11.10	10.35	9.79	11.62	14.97	16.97	20.71	19.91	19.72	16.25	11.40	10.58	14.45
Washington	10.51	10.71	10.93	11.24	13.06	13.39	14.61	15.02	14.67	11.69	11.14	10.74	12.31
West Virginia	9.16	9.18	9.17	9.90	12.37	15.80	18.77	18.05	14.48	11.24	9.76	9.43	12.28
Wisconsin	8.30	7.98	8.16	9.02	9.87	11.70	12.69	12.79	11.93	8.28	8.35	8.24	9.78
Wyoming	7.00	7.27	7.36	7.44	8.21	11.54	15.76	16.89	15.58	10.27	8.40	7.92	10.30

Table 8D.3.6 2013 Monthly Commercial Natural Gas Prices by State (2013$/tcf)

State	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg. 2013
United States	7.75	7.79	7.78	8.15	8.71	9.07	9.03	9.04	8.80	8.28	7.94	7.86	8.35
Alabama	11.91	12.02	11.80	12.34	13.24	13.58	13.58	13.41	13.33	12.72	12.24	11.78	12.66
Alaska	8.76	8.29	8.09	8.00	8.24	8.44	8.29	8.03	8.40	8.27	7.91	8.86	8.30
Arizona	8.39	8.46	8.43	8.99	8.97	9.03	9.35	9.37	9.32	8.97	8.78	8.55	8.88
Arkansas	7.37	7.52	7.13	7.62	8.33	8.86	8.89	8.78	8.70	8.38	7.65	7.24	8.04
California	7.52	7.09	7.52	7.63	7.97	8.58	8.15	8.17	7.60	7.60	8.07	8.48	7.87
Colorado	6.59	6.82	6.82	7.08	7.62	8.60	9.74	9.85	8.86	8.39	7.27	6.77	7.87
Connecticut	9.66	9.60	9.37	8.57	9.74	9.69	9.25	9.17	8.93	9.81	8.67	8.54	9.25
Delaware	11.13	11.11	11.21	11.60	12.70	13.67	14.07	14.64	14.49	13.90	12.17	11.02	12.64
District of Columbia	11.18	11.40	10.98	12.27	12.78	12.14	12.47	11.78	12.07	12.20	12.49	11.02	11.90
Florida	10.46	10.73	10.85	11.02	11.02	11.22	11.09	10.92	10.87	10.92	10.77	10.82	10.89
Georgia	8.86	8.84	8.39	9.57	10.33	10.97	11.02	11.13	10.91	10.34	8.94	8.21	9.79

State	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg. 2013
Hawaii	44.55	47.71	47.66	44.78	42.04	39.71	40.96	40.07	38.12	39.04	38.62	40.81	42.01
Idaho	7.07	6.96	7.19	7.27	7.41	7.24	7.15	7.15	7.07	7.71	7.54	7.61	7.28
Illinois	6.82	6.68	6.98	8.20	11.04	12.18	12.59	12.21	10.49	7.83	6.93	6.57	9.04
Indiana	7.07	7.44	7.32	9.58	11.88	11.05	9.93	9.81	8.82	6.89	6.66	6.57	8.59
Iowa	6.66	6.76	6.82	6.64	7.28	8.26	8.91	8.57	8.44	6.70	6.68	6.98	7.39
Kansas	8.22	8.13	8.23	9.06	10.23	13.30	13.96	13.51	13.61	11.96	9.15	8.32	10.64
Kentucky	7.30	7.32	7.15	7.95	9.75	11.35	11.79	11.36	11.64	9.94	8.79	8.30	9.39
Louisiana	8.45	8.51	8.20	8.89	9.21	9.30	8.60	8.57	8.50	8.48	8.61	8.24	8.63
Maine	14.39	14.63	14.19	14.45	13.55	11.05	11.42	11.54	10.49	8.91	10.17	10.84	12.14
Maryland	9.38	9.21	9.03	10.46	12.03	12.89	12.33	11.48	11.69	10.71	10.10	10.14	10.79
Massachusetts	11.36	11.09	11.34	11.37	11.46	10.88	11.36	11.15	10.67	10.18	11.48	11.68	11.17
Michigan	7.67	7.68	7.53	7.86	8.80	9.71	10.33	10.05	9.29	7.90	7.31	7.42	8.46
Minnesota	6.45	6.56	6.54	6.92	7.62	8.32	8.32	8.15	7.31	6.73	6.85	6.95	7.23
Mississippi	7.83	7.67	7.41	7.56	8.03	7.64	7.62	7.14	7.14	7.90	7.65	7.46	7.59
Missouri	8.17	8.32	8.29	8.83	9.53	11.38	12.41	11.80	11.89	11.19	9.72	8.44	10.00
Montana	7.54	7.80	7.77	8.01	9.08	9.74	9.98	9.71	9.94	8.27	7.99	7.66	8.62
Nebraska	6.35	6.22	6.29	6.31	6.49	7.21	7.59	6.93	7.29	6.75	6.43	6.62	6.71
Nevada	5.96	5.95	6.04	6.38	6.56	6.78	7.09	7.39	7.23	7.42	7.44	7.16	6.78
New Hampshire	10.92	11.05	11.98	11.87	12.41	13.32	15.41	15.64	16.34	13.03	12.26	13.15	13.12
New Jersey	9.57	9.56	9.81	8.90	9.29	9.87	9.91	9.53	9.35	9.39	9.90	9.51	9.55
New Mexico	6.22	6.26	6.30	6.51	7.15	7.94	8.24	8.08	8.00	7.66	7.29	6.70	7.20
New York	8.35	8.41	8.34	8.31	8.32	7.86	7.08	7.16	7.45	7.85	7.60	7.60	7.86
North Carolina	8.78	7.77	8.19	8.47	9.38	9.64	9.88	9.43	9.33	9.24	8.81	9.47	9.03
North Dakota	5.99	5.99	6.00	6.16	7.30	8.07	8.53	7.91	6.72	6.41	6.24	6.29	6.80
Ohio	6.18	5.91	5.63	6.24	6.71	6.28	7.12	7.17	7.07	6.62	6.30	6.22	6.45
Oklahoma	6.72	7.15	6.93	7.95	9.56	13.50	15.36	16.69	14.95	13.70	9.42	6.15	10.67
Oregon	8.03	8.43	8.79	8.73	8.78	8.97	9.05	9.45	9.05	8.48	8.33	8.89	8.75
Pennsylvania	9.61	9.58	9.95	10.34	11.54	12.47	12.98	12.68	12.52	10.61	9.67	9.63	10.97
Rhode Island	11.21	11.82	12.42	13.23	15.53	17.36	16.56	16.56	14.83	12.63	11.49	11.37	13.75
South Carolina	9.46	8.40	8.15	8.88	9.36	9.45	9.14	8.97	9.41	9.23	9.19	10.12	9.15
South Dakota	6.37	6.43	6.63	6.37	6.75	7.54	8.04	7.60	7.67	6.63	6.58	6.34	6.91
Tennessee	7.61	7.98	7.72	8.59	9.05	10.04	9.78	9.74	9.65	9.25	8.61	8.17	8.85
Texas	6.38	6.60	6.58	7.26	7.60	8.37	8.61	8.19	8.14	8.24	7.62	6.94	7.54
Utah	6.95	6.90	7.07	7.08	6.60	7.34	8.11	8.06	8.04	7.24	7.17	7.44	7.33
Vermont	9.00	9.69	9.06	8.90	7.38	6.90	6.07	5.53	5.45	5.37	6.08	7.19	7.22
Virginia	8.60	8.53	8.07	9.03	9.66	10.07	10.49	10.21	9.84	9.25	8.65	8.44	9.24
Washington	8.69	8.79	8.96	8.33	10.65	9.61	9.43	12.10	9.66	9.01	9.14	8.84	9.43
West Virginia	8.20	8.12	8.18	8.59	9.92	10.43	10.72	11.10	10.28	8.85	8.49	8.42	9.28
Wisconsin	7.21	7.00	7.05	7.39	7.19	7.58	7.26	6.99	6.66	5.97	6.98	7.19	7.04
Wyoming	6.34	6.40	6.32	6.14	6.54	7.40	8.45	8.05	8.60	7.64	7.34	7.11	7.19

All prices in 2013$ were converted to 2014$ to be consistent with the rest of the prices used in the analysis. This conversion was performed using Consumer Price Index.[b] DOE also

[b] www.bls.gov/cpi/

used a conversion factor (1.023) to convert from cubic feet of natural gas to MMBtu.[c] Table 8D.3.7 displays the 2013 shipment-weighted average residential natural gas prices by geographic region. Table 8D.3.8 displays the 2013 shipment-weighted average commercial natural gas prices by geographic region. For the 30 RECS 2009 regions or nine CBECS census divisions with more than one State, DOE weighted each State's average price by the average 2008-2012 fraction of boiler shipments by state.[3]

Table 8D.3.7 Average Residential Natural Gas Prices by RECS 2009 Region in 2013

ID	Geographic Area	2014$/MMBtu
1	Connecticut, Maine, New Hampshire, Rhode Island, Vermont	$16.20
2	Massachusetts	$14.81
3	New York	$15.21
4	New Jersey	$12.19
5	Pennsylvania	$14.67
6	Illinois	$11.00
7	Indiana, Ohio	$13.45
8	Michigan	$10.87
9	Wisconsin	$10.16
10	Iowa, Minnesota, North Dakota, South Dakota	$10.51
11	Kansas, Nebraska	$12.34
12	Missouri	$16.10
13	Virginia	$15.02
14	Delaware, District of Columbia, Maryland	$14.74
15	Georgia	$18.30
16	North Carolina, South Carolina	$16.48
17	Florida	$20.36
18	Alabama, Kentucky, Mississippi	$14.01
19	Tennessee	$12.66
20	Arkansas, Louisiana, Oklahoma	$13.30
21	Texas	$14.30
22	Colorado	$9.72
23	Idaho, Montana, Utah, Wyoming	$9.48
24	Arizona	$17.37
25	Nevada, New Mexico	$11.36
26	California	$10.63
27	Oregon, Washington	$12.76
28	Alaska	$9.34
29	Hawaii	$51.02
30	West Virginia	$12.76
	U.S. Average	$12.35

[c] www.eia.gov/tools/faqs/faq.cfm?id=45&t=7

Table 8D.3.8 Average Commercial Natural Gas Prices by CBECS 2003 Region in 2013

ID	Geographic Area	2014$/MMBtu
1	New England	$11.39
2	Middle Atlantic	$8.86
3	East North Central	$7.94
4	West North Central	$7.43
5	South Atlantic	$10.35
6	East South Central	$9.08
7	West South Central	$8.24
8	Mountain	$7.76
9	Pacific	$8.93
	U.S. Average	$8.29

8D.3.1.3 Annual LPG Prices

DOE collected 2013 average LPG prices from EIA's 2013 State Energy Consumption, Price, and Expenditures Estimates (SEDS).[6] SEDS includes annual LPG prices for residential, commercial, industrial, and transportation consumers by state. Table 8D.3.9 shows the annual residential LPG prices for each state. Table 8D.3.10 shows the annual commercial LPG prices for each state.

Table 8D.3.9 2013 Residential Average LPG Prices by State (2013$/MMBtu)

State	*Avg. 2013*
United States	17.61
Alabama	22.38
Alaska	26.07
Arizona	29.48
Arkansas	24.57
California	27.77
Colorado	24.81
Connecticut	30.05
Delaware	29.84
District of Columbia	28.24
Florida	26.66
Georgia	24.89
Hawaii	32.58
Idaho	24.15
Illinois	22.47
Indiana	24.74
Iowa	22.09
Kansas	21.45
Kentucky	23.24
Louisiana	13.95
Maine	28.98
Maryland	32.92

Massachusetts	32.47
Michigan	24.33
Minnesota	23.40
Mississippi	24.32
Missouri	22.98
Montana	22.86
Nebraska	23.42
Nevada	30.15
New Hampshire	29.60
New Jersey	32.24
New Mexico	17.60
New York	31.60
North Carolina	26.20
North Dakota	22.63
Ohio	27.26
Oklahoma	23.68
Oregon	25.04
Pennsylvania	29.50
Rhode Island	34.31
South Carolina	26.01
South Dakota	23.32
Tennessee	28.43
Texas	14.30
Utah	23.90
Vermont	29.84
Virginia	23.49
Washington	26.04
West Virginia	30.91
Wisconsin	22.39
Wyoming	23.20

Table 8D.3.10 2013 Commercial Average LPG Prices by State (2013$/MMBtu)

State	*Avg. 2013*
United States	21.23
Alabama	21.59
Alaska	20.38
Arizona	21.61
Arkansas	22.01
California	21.91
Colorado	20.18
Connecticut	24.68
Delaware	22.88
District of Columbia	24.24
Florida	17.42
Georgia	17.09
Hawaii	21.20
Idaho	20.79

Illinois	20.74
Indiana	20.89
Iowa	20.70
Kansas	20.74
Kentucky	20.70
Louisiana	21.59
Maine	24.37
Maryland	24.25
Massachusetts	24.66
Michigan	20.70
Minnesota	20.87
Mississippi	22.21
Missouri	20.35
Montana	19.61
Nebraska	20.60
Nevada	21.78
New Hampshire	23.21
New Jersey	24.48
New Mexico	21.83
New York	23.79
North Carolina	17.21
North Dakota	20.50
Ohio	20.60
Oklahoma	20.40
Oregon	20.38
Pennsylvania	24.25
Rhode Island	24.83
South Carolina	17.42
South Dakota	20.31
Tennessee	20.89
Texas	22.06
Utah	20.78
Vermont	24.60
Virginia	17.25
Washington	21.71
West Virginia	17.42
Wisconsin	20.50
Wyoming	20.40

All prices in 2013$ were converted to 2014$ to be consistent with the rest of the prices used in the analysis. This conversion was performed using Consumer Price Index.[d] Table 8D.3.11 shows the shipment-weighted average residential LPG prices for each geographic area. Table 8D.3.12 shows the shipment-weighted average commercial LPG prices for each geographic area. For the 30 RECS 2009 regions or nine CBECS census divisions with more than

[d] www.bls.gov/cpi/

one State, DOE weighted each State's average price by the average 2008-2012 fraction of boiler shipments by state.[3]

Table 8D.3.11 Average Residential LPG Prices by RECS 2009 Region in 2013

ID	Geographic Area	2014$/MMBtu
1	Connecticut, Maine, New Hampshire, Rhode Island, Vermont	$30.51
2	Massachusetts	$33.00
3	New York	$32.11
4	New Jersey	$32.76
5	Pennsylvania	$29.98
6	Illinois	$22.83
7	Indiana, Ohio	$27.01
8	Michigan	$24.72
9	Wisconsin	$22.75
10	Iowa, Minnesota, North Dakota, South Dakota	$23.30
11	Kansas, Nebraska	$22.98
12	Missouri	$23.35
13	Virginia	$23.87
14	Delaware, District of Columbia, Maryland	$33.32
15	Georgia	$25.29
16	North Carolina, South Carolina	$26.60
17	Florida	$27.09
18	Alabama, Kentucky, Mississippi	$23.67
19	Tennessee	$28.89
20	Arkansas, Louisiana, Oklahoma	$16.16
21	Texas	$14.53
22	Colorado	$25.21
23	Idaho, Montana, Utah, Wyoming	$23.76
24	Arizona	$29.96
25	Nevada, New Mexico	$20.84
26	California	$28.22
27	Oregon, Washington	$26.33
28	Alaska	$26.49
29	Hawaii	$33.11
30	West Virginia	$31.41
	U.S. Average	$17.90

Table 8D.3.12 Average Commercial LPG Prices by CBECS 2003 Region in 2013

ID	Geographic Area	2014$/MMBtu
1	New England	$24.63
2	Middle Atlantic	$24.44
3	East North Central	$20.99
4	West North Central	$21.08
5	South Atlantic	$22.67
6	East South Central	$21.26
7	West South Central	$22.07
8	Mountain	$20.77
9	Pacific	$21.84
	U.S. Average	$21.57

8D.3.1.4 Annual Fuel Oil Prices

DOE collected 2013 average fuel oil prices from EIA's SEDS.[6] SEDS includes annual fuel oil prices for residential, commercial, industrial, and transportation consumers by state. Table 8D.3.13 shows the annual residential fuel oil prices for each state. Table 8D.3.14 shows the annual commercial fuel oil prices for each state.

Table 8D.3.13 2013 Residential Average Fuel Oil Prices by State (2013$/MMBtu)

State	*Avg. 2013*
United States	28.23
Alabama	25.73
Alaska	27.46
Arizona	29.10
Arkansas	26.23
California	29.51
Colorado	25.09
Connecticut	28.15
Delaware	27.14
District of Columbia	28.75
Florida	28.23
Georgia	27.70
Hawaii	28.55
Idaho	25.85
Illinois	28.30
Indiana	28.50
Iowa	28.23
Kansas	28.29
Kentucky	28.23
Louisiana	25.73
Maine	27.79
Maryland	28.77
Massachusetts	28.12
Michigan	28.23

Minnesota	28.47
Mississippi	26.48
Missouri	27.76
Montana	24.39
Nebraska	28.10
Nevada	29.33
New Hampshire	26.47
New Jersey	29.04
New Mexico	26.01
New York	28.22
North Carolina	27.90
North Dakota	27.97
Ohio	28.10
Oklahoma	27.83
Oregon	27.45
Pennsylvania	28.77
Rhode Island	28.32
South Carolina	28.23
South Dakota	27.70
Tennessee	28.50
Texas	26.29
Utah	25.84
Vermont	28.06
Virginia	27.97
Washington	29.24
West Virginia	28.23
Wisconsin	27.97
Wyoming	25.36

Table 8D.3.14 2013 Commercial Average Fuel Oil Prices by State (2013$/MMBtu)

State	*Avg. 2013*
United States	28.23
Alabama	25.73
Alaska	27.46
Arizona	29.10
Arkansas	26.23
California	29.51
Colorado	25.09
Connecticut	28.15
Delaware	27.14
District of Columbia	28.75
Florida	28.23
Georgia	27.70
Hawaii	28.55
Idaho	25.85
Illinois	28.30
Indiana	28.50

Iowa	28.23
Kansas	28.29
Kentucky	28.23
Louisiana	25.73
Maine	27.79
Maryland	28.77
Massachusetts	28.12
Michigan	28.23
Minnesota	28.47
Mississippi	26.48
Missouri	27.76
Montana	24.39
Nebraska	28.10
Nevada	29.33
New Hampshire	26.47
New Jersey	29.04
New Mexico	26.01
New York	28.22
North Carolina	27.90
North Dakota	27.97
Ohio	28.10
Oklahoma	27.83
Oregon	27.45
Pennsylvania	28.77
Rhode Island	28.32
South Carolina	28.23
South Dakota	27.70
Tennessee	28.50
Texas	26.29
Utah	25.84
Vermont	28.06
Virginia	27.97
Washington	29.24
West Virginia	28.23
Wisconsin	27.97
Wyoming	25.36

All prices in 2013$ were converted to 2014$ to be consistent with the rest of the prices used in the analysis. This conversion was performed using Consumer Price Index.[e] Table 8D.3.15 shows the shipment-weighted average residential fuel oil prices for each geographic area. Table 8D.3.16 shows the shipment-weighted average commercial fuel oil prices for each geographic area. For the 30 RECS 2009 regions or nine CBECS census divisions with more than one State, DOE weighted each State's average price by the average 2008-2012 fraction of boiler shipments by state.[3]

[e] www.bls.gov/cpi/

Table 8D.3.15 Average Residential Fuel Oil Prices by Region in 2013

ID	Geographic Area	2014$/MMBtu
1	Connecticut, Maine, New Hampshire, Rhode Island, Vermont	$27.74
2	Massachusetts	$28.58
3	New York	$28.68
4	New Jersey	$29.51
5	Pennsylvania	$29.24
6	Illinois	$28.76
7	Indiana, Ohio	$28.67
8	Michigan	$28.69
9	Wisconsin	$28.42
10	Iowa, Minnesota, North Dakota, South Dakota	$28.80
11	Kansas, Nebraska	$28.64
12	Missouri	$28.21
13	Virginia	$28.42
14	Delaware, District of Columbia, Maryland	$29.18
15	Georgia	$28.15
16	North Carolina, South Carolina	$28.39
17	Florida	$28.69
18	Alabama, Kentucky, Mississippi	$28.27
19	Tennessee	$28.96
20	Arkansas, Louisiana, Oklahoma	$26.45
21	Texas	$26.72
22	Colorado	$25.50
23	Idaho, Montana, Utah, Wyoming	$25.52
24	Arizona	$29.57
25	Nevada, New Mexico	$27.21
26	California	$29.99
27	Oregon, Washington	$29.48
28	Alaska	$27.91
29	Hawaii	$29.01
30	West Virginia	$28.69
	U.S. Average	$28.69

Table 8D.3.16 Average Commercial Fuel Oil Prices by Region in 2013

ID	Geographic Area	2014$/MMBtu
1	New England	$28.09
2	Middle Atlantic	$28.99
3	East North Central	$28.64
4	West North Central	$28.75
5	South Atlantic	$28.97
6	East South Central	$28.63
7	West South Central	$26.56
8	Mountain	$25.84
9	Pacific	$29.42
	U.S. Average	$28.69

8D.3.2 Monthly Energy Price Factors Determination

For residential boilers, the Department of Energy (DOE) developed monthly energy price factors and used monthly energy consumption data for the life-cycle cost and payback period calculation. DOE developed monthly energy price factors to capture robust seasonal trends in monthly energy prices. To convert available annual energy prices into monthly energy prices, DOE determined monthly energy price factors.

8D.3.2.1 Monthly Residential Electricity Price Factor Calculations

DOE collected historical electricity prices from 1994 to 2013 from EIA's Form 826.[7] These data are published annually and include annual electricity sales, revenues from electricity sales, and average price for the residential, commercial, industrial, and transportation sectors by state. DOE aggregated the data into the RECS 2009 and CBECS 2003 regions as described in section 8D.1.

As an example, to illustrate the methodology for producing monthly price factors, the following tables and charts show the calculation of monthly average electricity price factors, based on New York historic electricity price data. Table 8D.3.17 shows the average residential electricity prices for New York.

Table 8D.3.17 1994-2013 Average Residential Electricity Prices for New York (nominal cents/kWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
1994	12.92	12.74	13.01	13.19	13.61	14.11	14.19	14.30	14.37	13.43	13.50	13.15	13.54
1995	13.16	13.11	13.34	13.54	14.06	14.63	14.69	14.58	14.51	13.76	13.81	13.50	13.89
1996	13.39	13.46	13.71	13.80	14.00	14.54	14.67	14.78	14.59	13.97	13.83	13.75	14.04
1997	13.75	13.67	13.83	13.69	13.84	14.70	14.80	14.68	14.56	14.01	13.93	13.84	14.11
1998	13.87	13.73	13.77	13.84	14.05	13.78	13.78	13.65	13.66	13.29	13.04	12.92	13.62
1999	12.85	12.75	12.95	13.34	12.85	13.44	13.44	13.54	13.74	13.64	13.44	13.24	13.27
2000	12.90	13.18	13.33	13.52	13.54	14.22	15.40	14.77	14.52	14.12	13.94	13.98	13.95
2001	13.89	13.93	13.58	13.44	14.01	14.41	14.99	14.61	14.23	14.22	13.53	13.25	14.01
2002	12.95	13.00	12.81	12.69	13.30	14.01	14.19	14.16	14.42	13.87	13.37	13.19	13.50
2003	12.77	13.30	13.91	14.55	14.77	14.98	15.14	14.94	14.92	14.75	14.23	13.63	14.32
2004	13.32	14.02	13.98	14.03	14.20	14.99	15.36	15.32	15.10	14.93	14.88	14.29	14.53
2005	14.05	14.53	14.40	14.64	15.36	15.58	15.63	16.16	16.69	17.36	17.57	16.53	15.71
2006	16.61	16.66	15.89	16.36	16.56	17.33	17.56	17.74	17.92	17.22	16.33	15.88	16.84
2007	16.09	15.89	16.83	17.14	17.50	18.17	17.27	17.96	17.15	17.48	16.94	16.66	17.09
2008	16.86	17.31	16.92	18.08	18.79	19.42	19.66	20.93	19.49	17.57	16.95	16.61	18.22
2009	16.83	16.72	16.40	16.57	16.86	18.22	18.79	18.21	18.75	18.12	16.72	17.47	17.47
2010	17.29	18.04	17.55	18.92	19.21	19.41	20.11	19.35	20.09	18.36	18.25	17.72	18.69
2011	17.25	17.45	17.58	17.63	18.30	19.07	19.22	19.25	18.84	18.78	17.93	17.26	18.21
2012	16.79	16.51	16.64	16.70	17.33	18.31	18.38	18.12	18.52	18.44	17.44	17.47	17.55
2013	17.93	19.10	18.16	17.67	18.35	19.32	20.03	19.14	19.56	18.88	18.49	18.18	18.73

DOE then calculated monthly energy price factors by dividing the monthly prices by the annual average for each year. Table 8D.3.18 and Figure 8D.3.1 show the calculated results for New York.

Table 8D.3.18 Monthly Electricity Price Factors for 1994-2013 for New York

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	0.95	0.94	0.96	0.97	1.00	1.04	1.05	1.06	1.06	0.99	1.00	0.97
1995	0.95	0.94	0.96	0.97	1.01	1.05	1.06	1.05	1.04	0.99	0.99	0.97
1996	0.95	0.96	0.98	0.98	1.00	1.04	1.04	1.05	1.04	0.99	0.98	0.98
1997	0.97	0.97	0.98	0.97	0.98	1.04	1.05	1.04	1.03	0.99	0.99	0.98
1998	1.02	1.01	1.01	1.02	1.03	1.01	1.01	1.00	1.00	0.98	0.96	0.95
1999	0.97	0.96	0.98	1.01	0.97	1.01	1.01	1.02	1.04	1.03	1.01	1.00
2000	0.92	0.94	0.96	0.97	0.97	1.02	1.10	1.06	1.04	1.01	1.00	1.00
2001	0.99	0.99	0.97	0.96	1.00	1.03	1.07	1.04	1.02	1.02	0.97	0.95
2002	0.96	0.96	0.95	0.94	0.99	1.04	1.05	1.05	1.07	1.03	0.99	0.98
2003	0.89	0.93	0.97	1.02	1.03	1.05	1.06	1.04	1.04	1.03	0.99	0.95
2004	0.92	0.96	0.96	0.97	0.98	1.03	1.06	1.05	1.04	1.03	1.02	0.98
2005	0.89	0.93	0.92	0.93	0.98	0.99	0.99	1.03	1.06	1.11	1.12	1.05
2006	0.99	0.99	0.94	0.97	0.98	1.03	1.04	1.05	1.06	1.02	0.97	0.94
2007	0.94	0.93	0.98	1.00	1.02	1.06	1.01	1.05	1.00	1.02	0.99	0.97
2008	0.93	0.95	0.93	0.99	1.03	1.07	1.08	1.15	1.07	0.96	0.93	0.91
2009	0.96	0.96	0.94	0.95	0.97	1.04	1.08	1.04	1.07	1.04	0.96	1.00
2010	0.93	0.97	0.94	1.01	1.03	1.04	1.08	1.04	1.07	0.98	0.98	0.95
2011	0.95	0.96	0.97	0.97	1.00	1.05	1.06	1.06	1.03	1.03	0.98	0.95
2012	0.96	0.94	0.95	0.95	0.99	1.04	1.05	1.03	1.06	1.05	0.99	1.00
2013	0.96	1.02	0.97	0.94	0.98	1.03	1.07	1.02	1.04	1.01	0.99	0.97

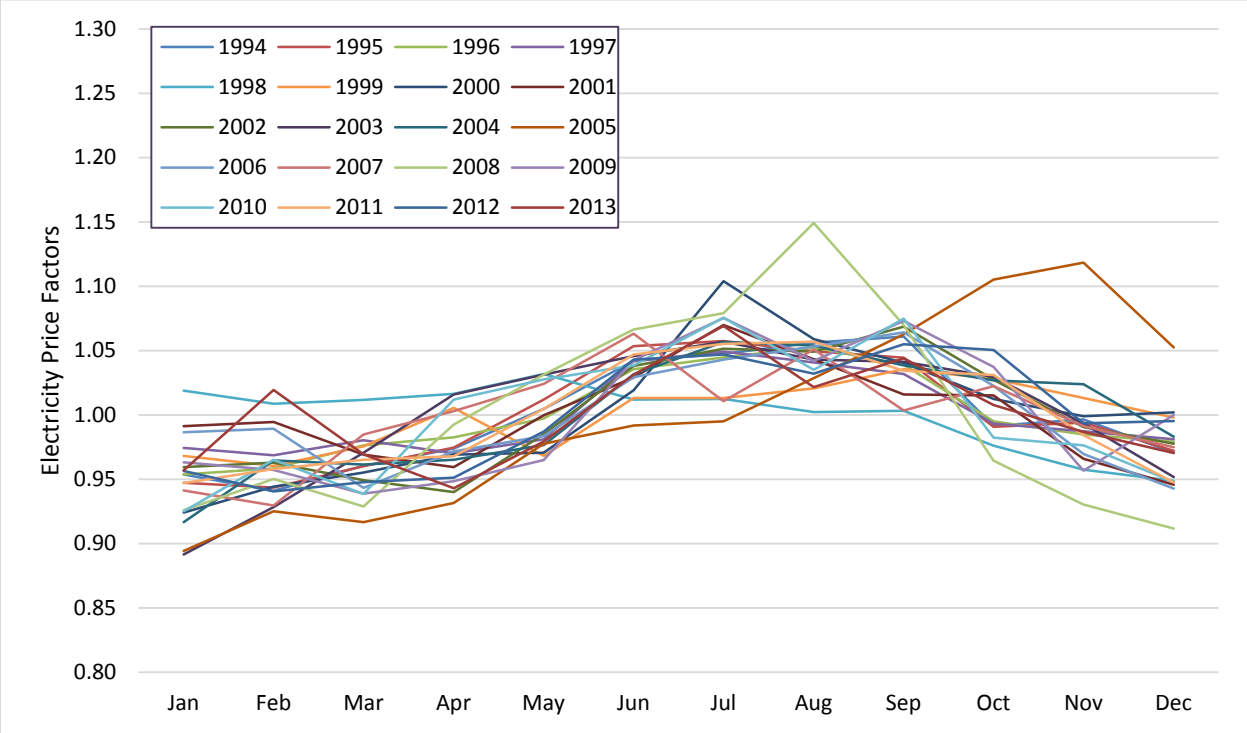

Figure 8D.3.1 Monthly Electricity Price Factors for 1994-2013 for New York

DOE then averaged the monthly energy price factors for 1994 to 2013 to develop an average energy price factor for each month. DOE performed the same calculations for each geographic region to develop the shipment-weighted average monthly energy price factors shown in Table 8D.3.19, which includes the results for New York, for RECS 2009 regions and Table 8D.3.20 for CBECS 2003 regions. For the 30 RECS 2009 regions or nine CBECS census divisions with more than one State, DOE weighted each State's average price by the average 2008-2012 fraction of boiler shipments by state.[3]

Table 8D.3.19 Monthly Residential Electricity Price Factors by RECS 2009 Regions

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	0.93	0.93	0.94	0.96	0.96	0.96	0.96	0.96	0.96	0.97	0.95	0.95
Massachusetts	0.93	0.94	0.94	0.94	0.95	0.98	0.95	0.96	0.97	0.96	0.94	0.97
New York	0.90	0.91	0.91	0.93	0.95	0.99	1.00	1.00	1.00	0.97	0.94	0.93
New Jersey	0.90	0.91	0.91	0.91	0.94	1.01	1.03	1.03	1.01	0.93	0.93	0.93
Pennsylvania	0.88	0.89	0.91	0.93	0.97	1.01	1.01	1.00	0.99	0.97	0.94	0.91
Illinois	0.85	0.89	0.92	0.97	1.00	1.01	1.00	0.99	1.00	0.99	0.93	0.87
Indiana, Ohio	0.85	0.88	0.91	0.96	1.00	1.01	0.99	0.99	1.00	0.99	0.95	0.89
Michigan	0.92	0.93	0.92	0.93	0.95	0.98	1.00	1.00	0.98	0.95	0.94	0.94
Wisconsin	0.91	0.94	0.93	0.95	0.97	0.98	0.96	0.96	0.97	0.97	0.95	0.93
Iowa, Minnesota, North Dakota, South Dakota	0.87	0.89	0.90	0.94	0.98	1.02	1.03	1.02	0.99	0.97	0.93	0.90
Kansas, Nebraska	0.82	0.86	0.88	0.92	0.96	1.06	1.07	1.07	1.06	0.95	0.91	0.86
Missouri	0.80	0.82	0.86	0.91	1.03	1.12	1.11	1.11	1.01	0.93	0.89	0.83
Virginia	0.87	0.89	0.91	0.95	0.99	1.01	1.01	1.02	0.99	0.97	0.93	0.89
Delaware, District of Columbia, Maryland	0.86	0.86	0.88	0.90	0.98	1.06	1.05	1.05	1.03	0.95	0.91	0.89
Georgia	0.86	0.89	0.92	0.93	0.97	1.03	1.05	1.06	1.01	0.95	0.91	0.86
North Carolina, South Carolina	0.89	0.91	0.93	0.96	0.97	0.95	0.97	0.97	0.99	1.01	0.96	0.92
Florida	0.93	0.95	0.95	0.96	0.95	0.94	0.95	0.96	0.96	0.96	0.97	0.95
Alabama, Kentucky, Mississippi	0.88	0.90	0.92	0.97	0.99	0.98	0.97	0.97	0.97	0.99	0.96	0.92
Tennessee	0.91	0.92	0.93	0.96	0.97	0.96	0.95	0.94	0.95	0.99	0.98	0.96
Arkansas, Louisiana, Oklahoma	0.88	0.91	0.93	0.94	0.96	0.98	0.99	0.99	1.00	1.00	0.94	0.90
Texas	0.88	0.89	0.92	0.95	0.96	1.00	1.00	1.00	0.99	0.98	0.94	0.92
Colorado	0.90	0.92	0.93	0.95	0.97	0.98	0.97	0.98	0.98	0.97	0.95	0.93
Idaho, Montana, Utah, Wyoming	0.91	0.92	0.92	0.92	0.95	0.98	0.99	0.99	0.98	0.99	0.94	0.93
Arizona	0.84	0.87	0.89	0.93	1.03	1.03	1.02	1.01	1.01	1.00	0.89	0.91
Nevada, New Mexico	0.91	0.92	0.93	0.95	0.96	0.97	0.97	0.98	0.97	0.98	0.94	0.93
California	0.95	0.93	0.92	0.92	0.95	0.98	1.00	0.99	0.96	0.91	0.95	0.97
Oregon, Washington	0.93	0.95	0.94	0.94	0.94	0.95	0.96	0.96	0.96	0.96	0.97	0.97
Alaska	0.91	0.91	0.94	0.95	0.97	0.97	0.99	0.98	0.96	0.96	0.95	0.94
Hawaii	0.92	0.92	0.92	0.93	0.94	0.95	0.96	0.97	0.97	0.98	0.98	0.98
West Virginia	0.90	0.91	0.93	0.96	0.99	0.97	0.95	0.96	0.97	1.00	0.97	0.92
United States	0.89	0.90	0.92	0.95	0.97	0.99	0.99	1.00	0.99	0.97	0.95	0.92

Table 8D.3.20 Monthly Commercial Electricity Price Factors by CBECS 2003 Regions

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	0.93	0.94	0.93	0.94	0.93	0.98	0.98	0.97	0.99	0.95	0.93	0.95
Middle Atlantic	0.90	0.91	0.90	0.91	0.93	1.00	1.04	1.03	1.01	0.97	0.91	0.92
East North Central	0.90	0.93	0.94	0.95	0.96	0.98	0.98	0.98	0.97	0.97	0.94	0.92
West North Central	0.88	0.90	0.91	0.92	0.96	1.03	1.05	1.05	0.99	0.93	0.91	0.90
South Atlantic	0.88	0.90	0.90	0.90	0.95	1.04	1.04	1.04	1.02	0.94	0.91	0.90
East South Central	0.92	0.95	0.95	0.95	0.96	0.96	0.95	0.96	0.95	0.96	0.97	0.96
West South Central	0.93	0.95	0.96	0.95	0.95	0.96	0.96	0.96	0.96	0.96	0.94	0.94
Mountain	0.91	0.93	0.93	0.94	0.96	0.98	0.96	0.97	0.97	0.98	0.96	0.93
Pacific	0.94	0.95	0.95	0.93	0.93	0.95	0.96	0.95	0.96	0.97	0.98	0.96
United States	0.91	0.92	0.93	0.93	0.95	0.99	1.00	1.00	0.99	0.97	0.94	0.92

8D.3.2.2 Monthly Residential Natural Gas Price Factor Calculations

DOE collected historical natural gas prices from 1994 to 2013 from the EIA's Natural Gas Navigator.[5] These data are published annually and include annual and monthly natural gas prices for residential, commercial, and industrial consumers by State. DOE aggregated the data into the RECS 2009 and CBECS 2003 regions as described in section 8D.1.

Again, as an example for how DOE determined monthly natural gas price factors, the methodology used to determine monthly average price factors can be seen below. Table 8D.3.21 shows the historic average residential gas prices for New York.

Table 8D.3.21 1994-2013 Average Residential Natural Gas Prices for New York ($/tcf)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Avg
1994	7.69	7.99	8.33	8.87	9.20	10.64	11.64	12.00	11.42	9.70	9.36	8.64	9.62
1995	8.10	7.66	7.66	7.88	8.70	10.20	11.64	12.00	11.81	11.09	8.70	7.77	9.43
1997	9.88	9.55	8.86	8.51	9.01	10.83	12.70	11.62	12.59	11.38	9.93	9.34	10.35
1998	9.17	9.09	8.90	9.56	10.73	11.99	7.08	13.24	12.66	11.62	9.50	9.30	10.24
1999	8.21	8.49	8.05	8.74	10.10	11.79	12.65	12.01	11.93	10.29	9.66	9.01	10.08
2000	7.97	8.49	9.55	9.82	11.66	13.30	14.81	14.68	15.05	12.15	10.16	9.02	11.39
2001	12.47	11.24	10.53	11.43	13.50	13.84	14.25	14.41	13.14	11.57	11.16	10.89	12.37
2002	9.35	8.65	9.17	9.34	9.96	11.66	13.04	13.18	13.21	11.84	10.08	9.48	10.75
2003	9.63	9.88	11.69	12.22	12.93	14.71	16.01	16.17	15.58	13.01	12.02	11.36	12.93
2004	11.41	11.33	11.48	11.51	13.07	15.34	16.29	16.89	16.22	14.41	13.44	13.19	13.72
2005	12.80	12.65	12.42	13.45	14.49	16.16	17.62	18.48	20.78	22.24	20.21	17.44	16.56
2006	16.61	15.11	13.99	14.58	16.09	16.69	18.04	18.91	18.43	13.37	14.75	14.97	15.96
2007	15.24	14.43	15.08	15.47	17.33	19.59	19.95	18.94	18.53	18.64	16.04	14.83	17.01
2008	14.99	14.91	15.21	16.76	19.95	22.88	24.96	24.20	21.66	18.42	16.48	16.26	18.89
2009	15.46	14.84	14.63	14.19	15.13	16.82	18.24	17.81	17.74	14.71	14.97	14.02	15.71
2010	12.97	13.01	13.60	15.08	15.82	18.42	20.00	20.17	18.54	16.47	13.88	12.09	15.84
2011	12.05	12.27	12.73	13.60	15.88	19.74	19.77	19.78	19.75	16.56	13.93	12.65	15.73
2012	11.67	11.69	12.99	13.06	15.13	18.00	17.40	18.78	18.16	15.26	11.35	11.97	14.62
2013	11.27	10.80	11.41	12.65	15.73	18.16	19.25	18.99	18.42	16.12	12.27	10.50	14.63
1994	7.69	7.99	8.33	8.87	9.20	10.64	11.64	12.00	11.42	9.70	9.36	8.64	9.62
1995	8.10	7.66	7.66	7.88	8.70	10.20	11.64	12.00	11.81	11.09	8.70	7.77	9.43
1997	9.88	9.55	8.86	8.51	9.01	10.83	12.70	11.62	12.59	11.38	9.93	9.34	10.35

DOE then calculated monthly energy price factors for each year by dividing the residential natural gas prices for each month by the natural gas annual average price for each year. Table 8D.3.22 and Figure 8D.3.2 show the calculated results for New York.

Table 8D.3.22 1994-2013 Monthly Natural Gas Price Factors for New York

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1994	0.80	0.83	0.87	0.92	0.96	1.11	1.21	1.25	1.19	1.01	0.97	0.90
1995	0.86	0.81	0.81	0.84	0.92	1.08	1.23	1.27	1.25	1.18	0.92	0.82
1997	0.95	0.92	0.86	0.82	0.87	1.05	1.23	1.12	1.22	1.10	0.96	0.90
1998	0.90	0.89	0.87	0.93	1.05	1.17	0.69	1.29	1.24	1.14	0.93	0.91
1999	0.81	0.84	0.80	0.87	1.00	1.17	1.26	1.19	1.18	1.02	0.96	0.89
2000	0.70	0.75	0.84	0.86	1.02	1.17	1.30	1.29	1.32	1.07	0.89	0.79
2001	1.01	0.91	0.85	0.92	1.09	1.12	1.15	1.16	1.06	0.94	0.90	0.88
2002	0.87	0.80	0.85	0.87	0.93	1.08	1.21	1.23	1.23	1.10	0.94	0.88
2003	0.74	0.76	0.90	0.94	1.00	1.14	1.24	1.25	1.20	1.01	0.93	0.88
2004	0.83	0.83	0.84	0.84	0.95	1.12	1.19	1.23	1.18	1.05	0.98	0.96
2005	0.77	0.76	0.75	0.81	0.87	0.98	1.06	1.12	1.25	1.34	1.22	1.05
2006	1.04	0.95	0.88	0.91	1.01	1.05	1.13	1.18	1.15	0.84	0.92	0.94
2007	0.90	0.85	0.89	0.91	1.02	1.15	1.17	1.11	1.09	1.10	0.94	0.87
2008	0.79	0.79	0.81	0.89	1.06	1.21	1.32	1.28	1.15	0.98	0.87	0.86
2009	0.98	0.94	0.93	0.90	0.96	1.07	1.16	1.13	1.13	0.94	0.95	0.89
2010	0.82	0.82	0.86	0.95	1.00	1.16	1.26	1.27	1.17	1.04	0.88	0.76
2011	0.77	0.78	0.81	0.86	1.01	1.26	1.26	1.26	1.26	1.05	0.89	0.80
2012	0.80	0.80	0.89	0.89	1.03	1.23	1.19	1.28	1.24	1.04	0.78	0.82
2013	0.77	0.74	0.78	0.86	1.08	1.24	1.32	1.30	1.26	1.10	0.84	0.72
1994	0.80	0.83	0.87	0.92	0.96	1.11	1.21	1.25	1.19	1.01	0.97	0.90
1995	0.86	0.81	0.81	0.84	0.92	1.08	1.23	1.27	1.25	1.18	0.92	0.82
1997	0.95	0.92	0.86	0.82	0.87	1.05	1.23	1.12	1.22	1.10	0.96	0.90

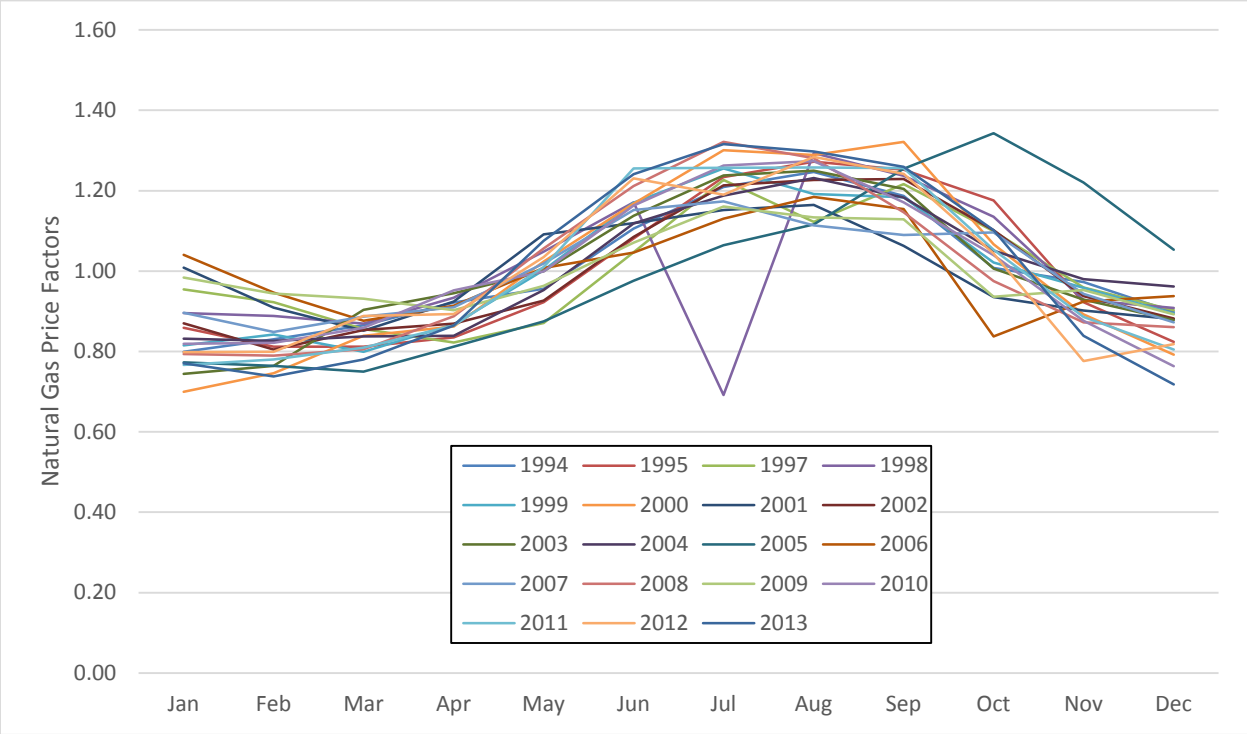

Figure 8D.3.2 1989-2011 Monthly Natural Gas Price Factors for New York

DOE then averaged the monthly energy price factors for 1994 to 2013 to develop an average energy price factor for each month. DOE performed the same calculations for each geographic area to develop the shipment-weighted average monthly energy price factors shown in Table 8D.3.23, which also includes the monthly energy price factor results calculated for New York, for RECS 2009 regions and Table 8D.3.24 for CBECS 2003 regions. For the 30 RECS 2009 regions or nine CBECS census divisions with more than one State, DOE weighted each State's average price by the average 2008-2012 fraction of boiler shipments by state.[3]

Table 8D.3.23 Monthly Residential Natural Gas Energy Price Factors by RECS 2009 Regions

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	0.86	0.86	0.87	0.86	0.91	0.98	1.10	1.12	1.08	0.96	0.92	0.90
Massachusetts	0.93	0.93	0.92	0.94	0.90	0.92	1.01	1.07	1.03	0.89	0.95	0.94
New York	0.84	0.83	0.84	0.88	0.98	1.12	1.18	1.11	1.08	0.95	0.84	0.79
New Jersey	0.87	0.86	0.87	0.88	0.94	1.03	1.07	1.07	1.05	0.97	0.92	0.89
Pennsylvania	0.77	0.78	0.80	0.83	0.94	1.09	1.21	1.24	1.17	0.96	0.84	0.80
Illinois	0.76	0.76	0.77	0.82	1.00	1.16	1.25	1.26	1.17	0.91	0.81	0.76
Indiana, Ohio	0.77	0.77	0.79	0.85	0.96	1.12	1.23	1.25	1.17	0.93	0.81	0.79
Michigan	0.79	0.79	0.80	0.84	0.94	1.08	1.19	1.23	1.14	0.94	0.85	0.82
Wisconsin	0.90	0.88	0.90	0.91	0.91	1.05	1.09	1.11	1.02	0.83	0.93	0.90
Iowa, Minnesota, North Dakota, South Dakota	0.81	0.80	0.81	0.83	0.94	1.11	1.19	1.23	1.15	0.91	0.85	0.81
Kansas, Nebraska	0.75	0.76	0.76	0.82	0.92	1.10	1.19	1.25	1.21	1.03	0.84	0.78
Missouri	0.69	0.69	0.70	0.78	0.91	1.12	1.29	1.36	1.27	1.07	0.83	0.73
Virginia	0.78	0.75	0.74	0.83	0.98	1.14	1.24	1.21	1.21	0.98	0.80	0.77
Delaware, District of Columbia, Maryland	0.77	0.76	0.78	0.86	0.99	1.13	1.21	1.21	1.16	0.94	0.82	0.78
Georgia	0.68	0.72	0.76	0.84	1.05	1.18	1.24	1.23	1.19	1.03	0.78	0.73
North Carolina, South Carolina	0.74	0.73	0.76	0.82	0.96	1.15	1.21	1.26	1.21	0.99	0.81	0.79
Florida	0.77	0.79	0.84	0.89	0.97	1.03	1.07	1.09	1.08	1.06	0.97	0.86
Alabama, Kentucky, Mississippi	0.74	0.75	0.76	0.85	1.01	1.14	1.19	1.23	1.17	0.98	0.82	0.78
Tennessee	0.77	0.78	0.79	0.86	0.94	1.09	1.16	1.19	1.14	1.03	0.87	0.81
Arkansas, Louisiana, Oklahoma	0.76	0.75	0.77	0.84	0.99	1.08	1.13	1.14	1.12	1.08	0.94	0.81
Texas	0.72	0.73	0.75	0.87	0.99	1.12	1.16	1.19	1.18	1.07	0.87	0.76
Colorado	0.77	0.78	0.80	0.83	0.92	1.18	1.19	1.26	1.16	0.92	0.83	0.78
Idaho, Montana, Utah, Wyoming	0.87	0.87	0.89	0.87	0.91	1.00	1.10	1.15	1.07	0.92	0.90	0.88
Arizona	0.73	0.75	0.78	0.86	0.96	1.06	1.16	1.20	1.16	1.08	0.91	0.78
Nevada, New Mexico	0.74	0.76	0.77	0.84	1.02	1.24	1.17	1.21	1.16	0.98	0.80	0.74
California	0.95	0.94	0.90	0.91	0.95	1.00	1.00	0.99	0.96	0.97	0.93	0.93
Oregon, Washington	0.85	0.87	0.87	0.90	0.94	0.99	1.07	1.11	1.08	0.97	0.90	0.88
Alaska	0.90	0.90	0.91	0.92	0.96	1.00	1.07	1.05	0.97	0.93	0.90	0.93
Hawaii	0.90	0.93	0.93	0.93	0.94	0.95	0.97	0.99	0.99	0.99	0.97	0.95
West Virginia	0.79	0.79	0.80	0.83	0.92	1.12	1.25	1.24	1.13	0.92	0.84	0.81
United States	0.81	0.81	0.82	0.87	0.96	1.08	1.15	1.17	1.12	0.96	0.86	0.83

Table 8D.3.24 Monthly Commercial Natural Gas Energy Price Factors by CBECS 2003 Regions

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	1.00	1.00	1.01	0.98	0.91	0.90	0.93	0.92	0.91	0.88	0.97	1.02
Middle Atlantic	1.03	1.02	0.99	0.96	0.95	0.93	0.90	0.88	0.89	0.91	0.96	1.01
East North Central	0.90	0.89	0.90	0.91	0.96	1.03	1.06	1.06	1.00	0.90	0.92	0.91
West North Central	0.94	0.93	0.93	0.90	0.96	0.99	1.02	1.02	0.98	0.89	0.94	0.94
South Atlantic	0.94	0.94	0.92	0.93	0.95	0.98	0.99	0.97	0.97	0.95	0.94	0.94
East South Central	0.91	0.91	0.91	0.93	0.94	0.97	0.99	1.01	0.98	0.97	0.95	0.94
West South Central	0.96	0.94	0.91	0.91	0.95	0.96	0.96	0.94	0.94	0.97	1.01	0.98
Mountain	0.91	0.91	0.92	0.91	0.94	0.98	1.02	1.04	1.01	0.94	0.93	0.92
Pacific	0.95	0.95	0.94	0.93	0.94	0.94	0.96	0.98	0.97	0.95	0.96	0.96
United States	0.95	0.95	0.94	0.95	0.95	0.97	0.97	0.96	0.95	0.93	0.95	0.96

8D.3.2.3 Monthly Residential LPG Price Factor Calculations

DOE collected historical liquid petroleum gas (LPG) prices from 1995 to 2009 from EIA's Short-Term Energy Outlook.[7] The Short-Term Energy Outlook includes monthly LPG prices by Census Region (Northeast, South, Midwest, and West).

The same process as used for electricity and natural gas price factors was used for calculating the monthly LPG price factors. These monthly price factors were calculated below, using data from the Northeast region. Table 8D.3.25 shows the Northeast residential LPG prices from 1995 to 2009.

Table 8D.3.25 Average LPG Prices for the Northeast (nominal cents/gallon)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1995	119	118	120	121	124	126	126	125	122	121	118	117
1996	123	125	128	125	130	131	129	127	127	133	135	145
1997	143	137	131	131	130	130	130	127	126	127	123	122
1998	121	120	120	123	124	124	122	121	119	118	115	114
1999	112	113	114	118	122	124	126	129	127	129	128	128
2000	132	148	148	145	148	151	155	154	157	159	156	160
2001	176	170	162	160	162	160	156	152	150	150	144	139
2002	139	138	139	143	142	144	143	141	141	142	142	142
2003	150	166	182	164	161	161	159	156	155	155	155	158
2004	169	173	171	168	170	173	173	176	181	187	193	187
2005	186	186	190	197	199	200	202	205	217	224	220	217
2006	221	220	220	225	231	237	242	244	240	232	229	228
2007	227	229	235	239	247	252	253	252	254	260	274	275
2008	282	280	284	292	306	320	333	329	324	305	280	267
2009	268	267	267	263	258	255	255	251	249	250	252	255

DOE then calculated monthly energy price factors for each year by dividing the prices for each month by the average price for each year. Table 8D.3.26 and Figure 8D.3.3 show the calculated results for the Northeast.

Table 8D.3.26 Monthly LPG Price Factors for 1995-2009 for the Northeast

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1995	0.98	0.97	0.99	1.00	1.02	1.03	1.04	1.03	1.00	1.00	0.97	0.96
1996	0.94	0.97	0.99	0.96	1.00	1.01	0.99	0.98	0.98	1.02	1.04	1.12
1997	1.10	1.06	1.01	1.01	1.01	1.00	1.00	0.98	0.97	0.98	0.95	0.94
1998	1.01	1.00	1.00	1.02	1.03	1.03	1.02	1.01	0.99	0.98	0.96	0.95
1999	0.92	0.92	0.93	0.96	1.00	1.02	1.03	1.05	1.04	1.06	1.05	1.04
2000	0.87	0.98	0.98	0.96	0.98	1.00	1.03	1.02	1.04	1.05	1.03	1.06
2001	1.12	1.08	1.03	1.02	1.04	1.02	0.99	0.97	0.96	0.96	0.92	0.89
2002	0.98	0.97	0.98	1.01	1.01	1.02	1.01	1.00	1.00	1.01	1.00	1.00
2003	0.94	1.04	1.13	1.03	1.01	1.00	1.00	0.97	0.97	0.97	0.97	0.99
2004	0.95	0.98	0.96	0.95	0.96	0.98	0.98	1.00	1.02	1.06	1.09	1.06
2005	0.91	0.91	0.93	0.97	0.98	0.98	0.99	1.01	1.07	1.10	1.08	1.07
2006	0.96	0.95	0.95	0.98	1.00	1.03	1.05	1.06	1.04	1.01	0.99	0.99
2007	0.91	0.92	0.94	0.96	0.99	1.01	1.01	1.01	1.02	1.04	1.10	1.10
2008	0.94	0.93	0.95	0.97	1.02	1.06	1.11	1.10	1.08	1.02	0.93	0.89
2009	1.04	1.04	1.04	1.02	1.00	0.99	0.99	0.97	0.97	0.97	0.98	0.99
Avg	0.97	0.98	0.99	0.99	1.00	1.01	1.02	1.01	1.01	1.01	1.00	1.00

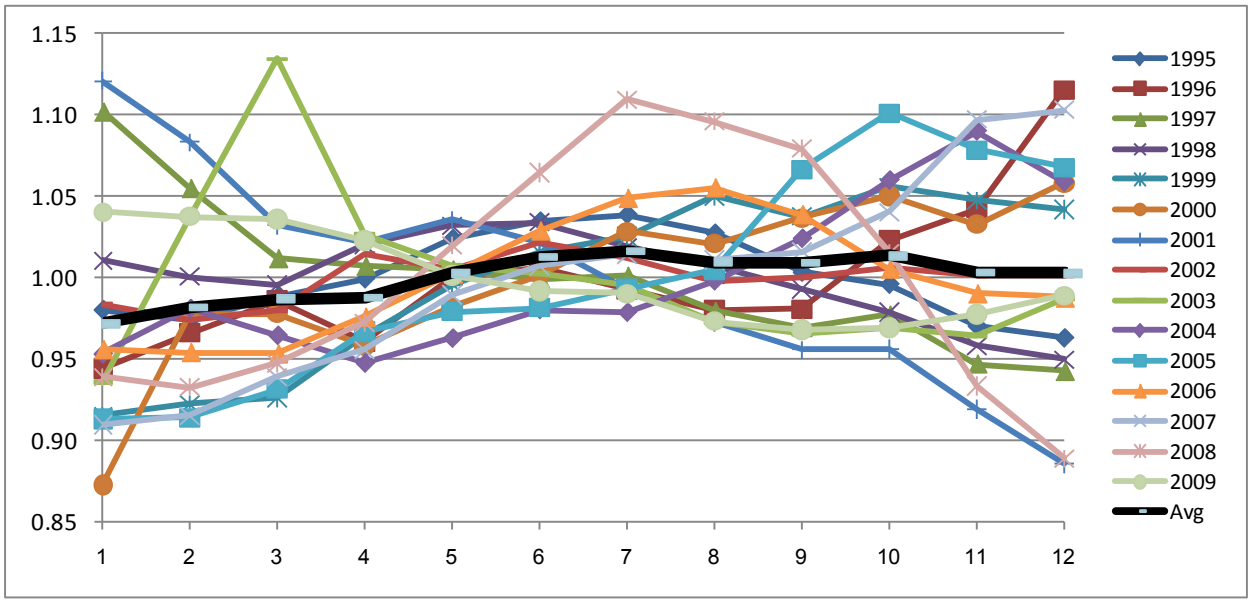

Figure 8D.3.3 Monthly LPG Factors for 1995-2009 for the Northeast (for months 1 to 12)

DOE then averaged the monthly energy price factors for 1995 to 2009 to develop an average energy price factor for each month. DOE performed the same calculations for each Census Region to develop the shipment-weighted average monthly energy price factors shown in Table 8D.3.27, which includes the calculated Northeast region monthly LPG energy price factors from 1995 to 2009. The commercial LPG price factors were calculated using the same historical

liquid petroleum gas (LPG) prices from 1995 to 2009 from EIA's Short-Term Energy Outlook[8] as the residential LPG price factors.

Table 8D.3.27 Monthly Residential LPG Energy Price Factors

Census Regions	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Northeast	0.97	0.98	0.99	0.99	1.00	1.01	1.02	1.01	1.01	1.01	1.00	1.00
South	1.04	1.04	1.03	1.01	1.00	0.97	0.94	0.93	0.96	0.98	1.03	1.07
Midwest	1.04	1.04	1.03	1.01	0.99	0.97	0.95	0.93	0.96	1.00	1.03	1.06
West	1.05	1.05	1.03	1.01	0.99	0.96	0.92	0.91	0.95	1.01	1.04	1.08
United States	1.02	1.03	1.02	1.02	1.02	1.00	0.95	0.93	0.96	0.99	1.02	1.05

8D.3.3 Monthly Residential Oil Price Factor Calculations

DOE collected historical oil prices from 1995 to 2009 from EIA's Short-Term Energy Outlook.[8] The Short-Term Energy Outlook includes monthly oil prices by Census division (Northeast, South, Midwest, and West).

The same methodology for calculating monthly energy price factors for residential fuel oil. These monthly price factors were calculated below, using data from the Northeast region (Census division 1). Table 8D.3.28 shows the Northeast residential oil prices from 1995 to 2009.

Table 8D.3.28 Average Residential Oil Prices for Census Division 1 (nominal cents/gallon)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1995	91.9	92.6	91.7	90.2	91.7	90.2	87.2	86	87.2	88.9	91.2	96.8
1996	101.1	102.6	106.1	108.3	103.8	96.6	92.5	92.4	99.4	109	111.6	114.1
1997	114.4	111.6	107.5	105.4	102.6	98.4	93.6	91.2	93.3	97.8	99.5	99.6
1998	98.3	97.6	95.3	93.2	90.7	86.5	82.3	79.6	81.1	83.2	84.6	83.6
1999	85.4	84.7	85.4	87.2	86.4	85.1	85	86	93.6	99.5	105	109.8
2000	135	154	130.5	123.7	124	124	122.2	125.6	139.3	144.2	147.8	149.3
2001	146	141.4	136.9	134.7	131.9	127	121	121.2	123.7	121.4	118.4	115.9
2002	117.7	116.2	118.2	119.9	118.4	116	112.5	111.9	117.1	121.2	124.8	130.9
2003	140.9	159.8	163.4	143.6	137.3	132	125.5	125.9	128.4	132	136.7	142.4
2004	150.8	153	150.1	149.2	151	151	152.1	159.1	168.7	189.6	192.3	189.5
2005	191	194.4	203.8	206.4	202	211	216.8	229.6	252.3	251.8	242.9	243.7
2006	246.2	243.5	247.3	255	259.7	260	259.2	262.7	252.2	244.6	247.4	251.3
2007	245	254.2	258.2	261	261.6	263	269.6	263.4	273.7	288	318	325.3
2008	330.2	333.7	363.6	378.9	409.7	442	454.5	407.7	384.9	334.2	296.3	262.6
2009	259.4	246.9	237	236.6	231.8	246	240.7	253	248	259.7	272.1	276.4

DOE then calculated monthly energy price factors by dividing the monthly prices by the average price for each year. Table 8D.3.29 and Figure 8D.3.4 show the calculated results for the Northeast.

Table 8D.3.29 Monthly Oil Price Factors for 1995-2009 for Census Division 1

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1995	1.02	1.02	1.01	1.00	1.01	1.00	0.96	0.95	0.96	0.98	1.01	1.07
1996	0.98	0.99	1.03	1.05	1.01	0.94	0.90	0.90	0.96	1.06	1.08	1.11
1997	1.13	1.10	1.06	1.04	1.01	0.97	0.92	0.90	0.92	0.97	0.98	0.98
1998	1.12	1.11	1.08	1.06	1.03	0.98	0.94	0.90	0.92	0.95	0.96	0.95
1999	0.94	0.93	0.94	0.96	0.95	0.93	0.93	0.94	1.03	1.09	1.15	1.21
2000	1.00	1.14	0.97	0.92	0.92	0.92	0.91	0.93	1.03	1.07	1.10	1.11
2001	1.14	1.10	1.07	1.05	1.03	0.99	0.94	0.94	0.96	0.95	0.92	0.90
2002	0.99	0.98	1.00	1.01	1.00	0.98	0.95	0.94	0.99	1.02	1.05	1.10
2003	1.01	1.15	1.18	1.03	0.99	0.95	0.90	0.91	0.92	0.95	0.98	1.02
2004	0.93	0.94	0.92	0.92	0.93	0.92	0.93	0.98	1.04	1.16	1.18	1.16
2005	0.87	0.88	0.92	0.94	0.92	0.95	0.98	1.04	1.14	1.14	1.10	1.11
2006	0.98	0.96	0.98	1.01	1.03	1.03	1.03	1.04	1.00	0.97	0.98	1.00
2007	0.90	0.93	0.94	0.95	0.96	0.96	0.99	0.96	1.00	1.05	1.16	1.19
2008	0.90	0.91	0.99	1.03	1.12	1.21	1.24	1.11	1.05	0.91	0.81	0.72
2009	1.04	0.99	0.95	0.94	0.92	0.98	0.96	1.01	0.99	1.04	1.09	1.10
Avg	0.99	1.01	1.00	0.99	0.99	0.98	0.97	0.96	0.99	1.02	1.04	1.05

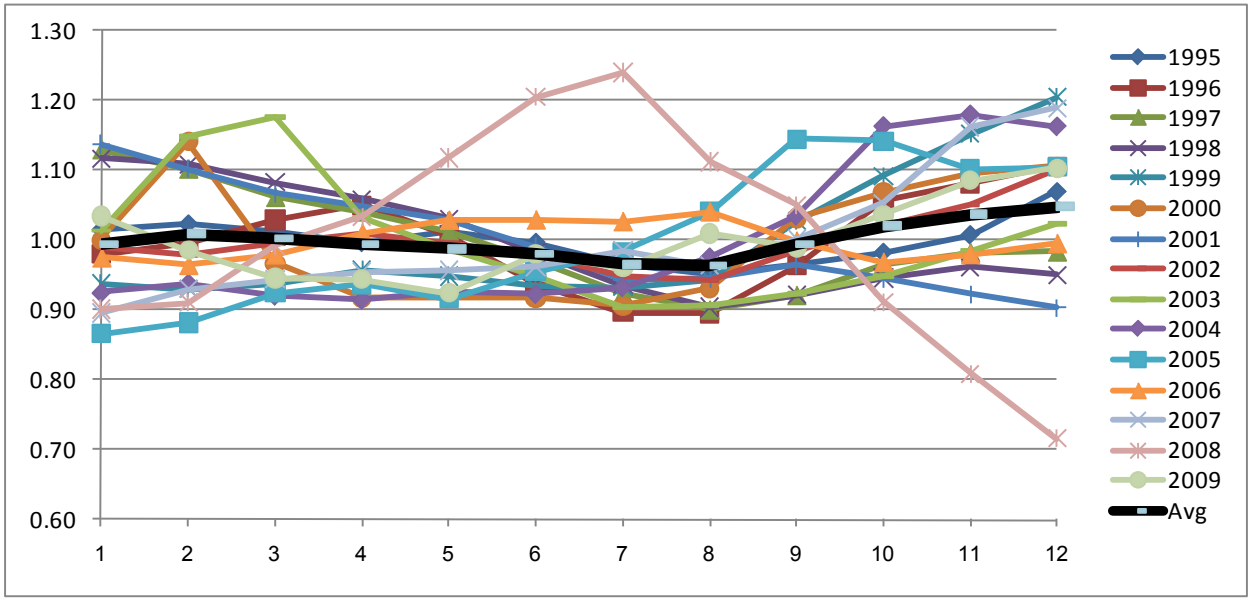

Figure 8D.3.4 Monthly Oil Price Factors for 1995-2009 for Census Division 1 (for months 1 to 12)

DOE then averaged the monthly energy price factors for 1995 to 2009 to develop an average energy price factor for each month. DOE performed the same calculations for each Census Region to develop the shipment-weighted average monthly energy price factors shown in Table 8D.3.30 which includes the calculated Northeast region monthly oil energy price factors. The commercial fuel oil price factors were calculated using the same historical fuel oil prices from 1995 to 2009 from EIA's Short-Term Energy Outlook[8] as the residential fuel oil price factors.

Table 8D.3.30 Monthly Residential Oil Energy Price Factors

Census Regions	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Northeast	0.99	1.01	1.00	0.99	0.99	0.98	0.97	0.96	0.99	1.02	1.04	1.05
South	0.96	0.97	0.98	0.99	0.98	0.98	0.98	1.00	1.03	1.05	1.05	1.04
Midwest	1.00	1.02	1.01	1.00	0.97	0.95	0.96	0.96	1.00	1.03	1.05	1.06
West	0.93	0.95	0.99	1.01	1.01	1.00	0.99	0.99	1.02	1.04	1.04	1.02
United States	0.99	1.01	1.00	0.99	0.99	0.98	0.96	0.97	1.00	1.02	1.04	1.05

8D.3.4 Seasonal Marginal Price Factors Determination

Marginal energy prices are the prices consumers pay for the last unit of energy used. Because marginal prices reflect a change in a consumer's bill associated with a change in energy consumed, such prices are appropriate for determining energy cost savings associated with potential efficiency standards.

Because it is difficult to derive representative marginal energy prices from utility tariff information,[f] DOE developed an alternative method, which uses EIA's historical (2004-2013) monthly residential and commercial electricity and natural gas consumption and expenditures by state.[4,5] For each state, DOE plotted consumption vs. expenditures and interpreted the slope of the regression line as the marginal energy price for that state. Figure 8D.3.5 for New York natural gas data in 2012 (winter months) shows an example. The slope of the regression line is $10.603/1000 cu ft, which DOE interpreted to be the average marginal price in the winter months of 2012. During that same period (2012 winter months) the average natural gas price was $11.878/1000 cu ft. Therefore, the marginal price factor (marginal price divided by average price) was determined to be 0.89 for winter of 2012 in New York. Since marginal price may very year by year, DOE used the average marginal price factors for each state over a 10-year period (2004-2013). Because a boiler operates during both the heating and cooling seasons, DOE determined non-winter and winter marginal price factors.[g]

[f] Section 8.D.5 describes an analysis that DOE conducted using 23 residential gas tariffs for 13 companies operating in multiple states that were provided by the Gas Technology Institute. DOE used this information to validate the residential natural gas marginal price factors presented in this section. In addition, EIA provided RECS 2009 billing data that had been gathered from a subset of RECS housing records. For each household with billing data, the following are provided for each billing cycle: the start and end date, the electricity consumption in kWh, the electricity cost in dollars, the natural gas bill in dollars, and the gas consumption in hundreds of cubic feet. This data was also used to validate marginal energy price factors by RECS 2009 geographical area. DOE's natural gas marginal price factors are on average 0.4% lower than those derived using RECS 2009 billing data.

[g] Non-winter months are from April to October, while winter months are from December to March.

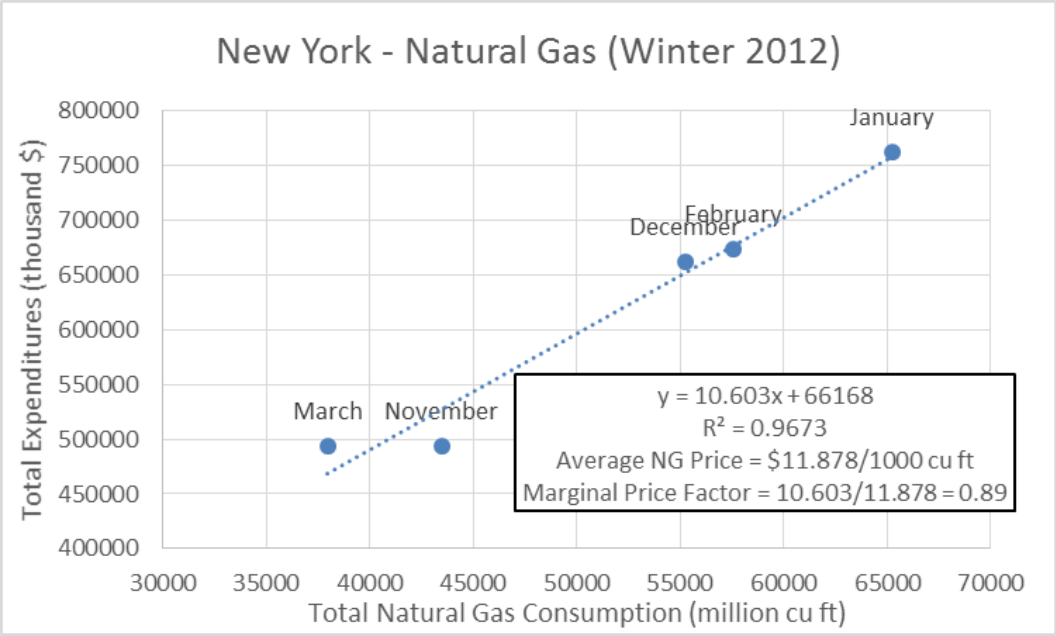

Figure 8D.3.5 Total Natural Gas Expenditures Compared to Total Natural Gas Consumption for New York, Winter Months 2012

Table 8D.3.31 through Table 8D.3.34 show the estimated marginal electricity and natural gas marginal price factors. These factors are used to convert average monthly energy prices into marginal monthly energy prices. For the 30 RECS 2009 regions or nine CBECS census divisions with more than one State, DOE weighted each State's average price by the average 2008-2012 fraction of boiler shipments by state.[3]

Table 8D.3.31 Residential Marginal Electricity Price Factors by RECS 2009 Regions

ID	Geographical Area	Non-Winter	Winter
1	Connecticut, Maine, New Hampshire, Rhode Island, Vermont	0.93	0.96
2	Massachusetts	0.95	1.04
3	New York	1.14	0.91
4	New Jersey	1.20	0.99
5	Pennsylvania	1.07	0.83
6	Illinois	0.96	0.71
7	Indiana, Ohio	1.04	0.75
8	Michigan	1.13	0.96
9	Wisconsin	1.02	0.89
10	Iowa, Minnesota, North Dakota, South Dakota	1.09	0.85
11	Kansas, Nebraska	1.21	0.73
12	Missouri	1.23	0.76
13	Virginia	1.08	0.83
14	Delaware, District of Columbia, Maryland	1.16	0.92
15	Georgia	1.18	0.85
16	North Carolina, South Carolina	0.97	0.83
17	Florida	1.02	0.94
18	Alabama, Kentucky, Mississippi	0.98	0.84
19	Tennessee	0.94	0.86
20	Arkansas, Louisiana, Oklahoma	1.04	0.82
21	Texas	1.04	0.91
22	Colorado	1.11	0.80
23	Idaho, Montana, Utah, Wyoming	1.04	0.92
24	Arizona	1.05	0.84
25	Nevada, New Mexico	1.12	0.89
26	California	1.20	1.12
27	Oregon, Washington	0.86	0.94
28	Alaska	0.86	0.90
29	Hawaii	1.36	0.96
30	West Virginia	0.93	0.85
	United States	1.07	0.85

Table 8D.3.32 Commercial Marginal Electricity Price Factors by CBECS 2003 Regions

ID	Geographical Area	Non-Winter	Winter
1	New England	1.10	0.94
2	Middle Atlantic	1.49	0.98
3	East North Central	1.14	0.75
4	West North Central	1.56	0.67
5	South Atlantic	1.19	1.22
6	East South Central	1.02	0.72
7	West South Central	1.09	0.51
8	Mountain	1.16	1.02
9	Pacific	1.12	0.85
	United States	1.34	0.80

Table 8D.3.33 Residential Marginal Natural Gas Price Factors by RECS 2009 Regions

ID	Geographical Area	Non-Winter	Winter
1	Connecticut, Maine, New Hampshire, Rhode Island, Vermont	0.83	0.94
2	Massachusetts	0.88	1.04
3	New York	0.73	0.89
4	New Jersey	0.83	0.98
5	Pennsylvania	0.71	0.93
6	Illinois	0.66	0.96
7	Indiana, Ohio	0.68	0.92
8	Michigan	0.78	0.97
9	Wisconsin	0.79	0.98
10	Iowa, Minnesota, North Dakota, South Dakota	0.71	0.97
11	Kansas, Nebraska	0.67	0.94
12	Missouri	0.57	0.81
13	Virginia	0.67	0.95
14	Delaware, District of Columbia, Maryland	0.66	0.93
15	Georgia	0.55	0.87
16	North Carolina, South Carolina	0.65	0.92
17	Florida	0.64	0.81
18	Alabama, Kentucky, Mississippi	0.66	0.86
19	Tennessee	0.73	0.93
20	Arkansas, Louisiana, Oklahoma	0.63	0.83
21	Texas	0.59	0.84
22	Colorado	0.68	0.90
23	Idaho, Montana, Utah, Wyoming	0.83	0.94
24	Arizona	0.64	0.85
25	Nevada, New Mexico	0.67	0.91
26	California	0.83	1.08
27	Oregon, Washington	0.84	0.94
28	Alaska	0.87	0.98
29	Hawaii	0.77	1.02
30	West Virginia	0.78	0.96
	United States	0.72	0.94

Table 8D.3.34 Commercial Marginal Natural Gas Price Factors by CBECS 2003 Regions

ID	Geographical Area	Summer	Winter
1	New England	1.02	1.00
2	Middle Atlantic	1.03	0.99
3	East North Central	0.81	0.99
4	West North Central	0.84	1.02
5	South Atlantic	0.90	0.95
6	East South Central	0.86	0.94
7	West South Central	0.77	0.94
8	Mountain	0.86	0.99
9	Pacific	0.93	1.03
	United States	0.90	0.99

8D.3.5 Monthly Energy Prices for 2013

DOE applied the regional monthly energy price factors to develop residential and commercial monthly average energy prices for 2013 for electricity, natural gas, LPG, and oil (Table 8D.3.36 through Table 8D.3.43). DOE then applied the electricity and natural gas marginal price factors to the average monthly energy prices to estimate 2013 marginal prices for electricity and natural gas (Table 8D.3.44 through Table 8D.3.47). For LPG and fuel oil, DOE assumed average and marginal monthly prices are the same. Average energy prices are applied to the base case energy use, while marginal prices are applied to the energy savings from the higher efficiency options.

8D.3.5.1 Average Monthly Energy Prices

Table 8D.3.36 Residential Average Monthly Electricity Prices for 2013 Using Price Factors by RECS 2009 Regions (2014$/kWh)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	0.156	0.157	0.158	0.161	0.162	0.162	0.161	0.161	0.161	0.163	0.160	0.159
Massachusetts	0.150	0.151	0.151	0.151	0.153	0.157	0.152	0.154	0.156	0.154	0.152	0.156
New York	0.172	0.174	0.174	0.177	0.181	0.188	0.191	0.190	0.189	0.184	0.180	0.176
New Jersey	0.144	0.144	0.145	0.145	0.149	0.160	0.164	0.164	0.160	0.148	0.147	0.147
Pennsylvania	0.115	0.116	0.118	0.122	0.127	0.132	0.132	0.131	0.129	0.127	0.122	0.119
Illinois	0.092	0.097	0.100	0.105	0.109	0.110	0.109	0.107	0.108	0.107	0.101	0.094
Indiana, Ohio	0.102	0.105	0.109	0.115	0.120	0.121	0.119	0.119	0.119	0.118	0.114	0.107
Michigan	0.137	0.138	0.137	0.139	0.141	0.146	0.148	0.149	0.145	0.141	0.139	0.140
Wisconsin	0.126	0.130	0.128	0.132	0.134	0.135	0.132	0.132	0.134	0.133	0.132	0.129
Iowa, Minnesota, North Dakota, South Dakota	0.101	0.103	0.105	0.109	0.113	0.118	0.119	0.118	0.115	0.112	0.107	0.104
Kansas, Nebraska	0.091	0.095	0.097	0.102	0.106	0.117	0.118	0.119	0.117	0.105	0.101	0.095
Missouri	0.086	0.089	0.093	0.098	0.111	0.121	0.120	0.119	0.109	0.100	0.096	0.090
Virginia	0.096	0.098	0.101	0.105	0.110	0.112	0.112	0.112	0.110	0.107	0.103	0.098
Delaware, District of Columbia, Maryland	0.116	0.116	0.118	0.121	0.132	0.143	0.142	0.141	0.138	0.128	0.122	0.120
Georgia	0.099	0.103	0.106	0.107	0.112	0.120	0.121	0.123	0.117	0.110	0.105	0.100
North Carolina, South Carolina	0.101	0.103	0.105	0.109	0.109	0.107	0.110	0.110	0.112	0.114	0.108	0.104
Florida	0.107	0.108	0.109	0.110	0.109	0.108	0.109	0.109	0.110	0.110	0.111	0.109
Alabama, Kentucky, Mississippi	0.090	0.092	0.094	0.099	0.101	0.101	0.099	0.099	0.099	0.101	0.098	0.094
Tennessee	0.093	0.093	0.095	0.097	0.099	0.098	0.096	0.096	0.096	0.100	0.100	0.097
Arkansas, Louisiana, Oklahoma	0.084	0.087	0.089	0.090	0.093	0.094	0.095	0.095	0.096	0.096	0.090	0.087
Texas	0.102	0.103	0.106	0.109	0.111	0.115	0.115	0.115	0.114	0.113	0.108	0.106
Colorado	0.109	0.111	0.112	0.114	0.117	0.119	0.118	0.118	0.118	0.117	0.115	0.112
Idaho, Montana, Utah, Wyoming	0.095	0.096	0.096	0.097	0.100	0.103	0.104	0.103	0.103	0.103	0.099	0.098
Arizona	0.099	0.102	0.104	0.110	0.122	0.121	0.119	0.119	0.118	0.118	0.105	0.106
Nevada, New Mexico	0.108	0.110	0.111	0.113	0.115	0.116	0.116	0.117	0.115	0.117	0.112	0.111
California	0.156	0.152	0.151	0.151	0.156	0.160	0.163	0.163	0.157	0.150	0.156	0.158
Oregon, Washington	0.084	0.085	0.085	0.085	0.085	0.086	0.086	0.087	0.087	0.087	0.088	0.088
Alaska	0.167	0.169	0.173	0.175	0.180	0.179	0.183	0.181	0.178	0.178	0.176	0.174
Hawaii	0.345	0.346	0.346	0.349	0.354	0.359	0.362	0.365	0.364	0.370	0.369	0.367
West Virginia	0.087	0.088	0.091	0.093	0.096	0.094	0.093	0.093	0.095	0.097	0.094	0.090
United States	0.109	0.111	0.113	0.117	0.120	0.122	0.122	0.123	0.122	0.120	0.117	0.113

Table 8D.3.37 Commercial Average Monthly Electricity Prices for 2013 Using Price Factors by CBECS 2003 Regions (2014$/ kWh)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	0.131	0.134	0.132	0.133	0.132	0.139	0.139	0.138	0.140	0.135	0.131	0.134
Middle Atlantic	0.123	0.123	0.123	0.123	0.127	0.137	0.141	0.140	0.138	0.132	0.124	0.125
East North Central	0.088	0.091	0.091	0.093	0.094	0.096	0.096	0.096	0.095	0.095	0.092	0.090
West North Central	0.080	0.082	0.083	0.084	0.088	0.094	0.096	0.096	0.091	0.085	0.083	0.082
South Atlantic	0.090	0.091	0.091	0.091	0.097	0.105	0.105	0.105	0.104	0.095	0.092	0.092
East South Central	0.089	0.091	0.091	0.092	0.093	0.093	0.091	0.092	0.092	0.093	0.093	0.092
West South Central	0.080	0.082	0.082	0.081	0.081	0.082	0.082	0.083	0.082	0.083	0.081	0.081
Mountain	0.088	0.090	0.090	0.092	0.093	0.095	0.093	0.093	0.094	0.095	0.093	0.090
Pacific	0.093	0.094	0.094	0.092	0.092	0.094	0.095	0.094	0.095	0.096	0.097	0.095
United States	0.094	0.096	0.097	0.097	0.099	0.103	0.104	0.104	0.103	0.101	0.098	0.096

Table 8D.3.38 Residential Average Monthly Natural Gas Prices for 2013 Using Price Factors by RECS 2009 Regions (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	13.88	13.97	14.17	14.01	14.66	15.92	17.77	18.18	17.52	15.52	14.96	14.57
Massachusetts	13.76	13.75	13.64	13.97	13.26	13.59	15.01	15.79	15.24	13.18	14.07	13.98
New York	12.79	12.57	12.77	13.35	14.86	17.00	17.89	16.83	16.50	14.50	12.80	11.98
New Jersey	10.64	10.52	10.55	10.76	11.45	12.56	13.10	13.05	12.86	11.86	11.17	10.84
Pennsylvania	11.35	11.46	11.69	12.23	13.77	15.98	17.70	18.18	17.23	14.08	12.33	11.67
Illinois	8.38	8.41	8.49	9.02	11.01	12.74	13.71	13.85	12.87	10.04	8.89	8.35
Indiana, Ohio	10.31	10.39	10.69	11.49	12.91	15.06	16.49	16.77	15.68	12.48	10.87	10.56
Michigan	8.60	8.62	8.73	9.17	10.26	11.72	12.97	13.39	12.35	10.25	9.26	8.93
Wisconsin	9.18	8.95	9.13	9.28	9.24	10.69	11.11	11.29	10.32	8.41	9.40	9.15
Iowa, Minnesota, North Dakota, South Dakota	8.52	8.37	8.51	8.68	9.87	11.66	12.53	12.90	12.05	9.57	8.94	8.50
Kansas, Nebraska	9.32	9.37	9.36	10.17	11.39	13.59	14.73	15.45	14.97	12.76	10.33	9.63
Missouri	11.06	11.08	11.23	12.59	14.59	18.05	20.69	21.90	20.40	17.25	13.40	11.80
Virginia	11.72	11.24	11.11	12.40	14.68	17.14	18.56	18.24	18.19	14.72	12.03	11.64
Delaware, District of Columbia, Maryland	11.36	11.21	11.50	12.70	14.64	16.70	17.86	17.82	17.14	13.87	12.11	11.57
Georgia	12.44	13.26	13.85	15.44	19.16	21.56	22.74	22.53	21.87	18.76	14.24	13.34
North Carolina, South Carolina	12.14	12.05	12.48	13.58	15.81	18.97	20.02	20.80	19.89	16.37	13.32	12.96
Florida	15.73	16.08	17.15	18.16	19.80	21.06	21.75	22.23	21.91	21.54	19.75	17.52
Alabama, Kentucky, Mississippi	10.38	10.45	10.70	11.98	14.14	15.96	16.65	17.21	16.45	13.78	11.46	10.93
Tennessee	9.75	9.89	9.94	10.85	11.93	13.76	14.68	15.11	14.48	13.10	10.97	10.26
Arkansas, Louisiana, Oklahoma	10.08	10.02	10.26	11.21	13.20	14.36	15.01	15.23	14.92	14.40	12.50	10.83
Texas	10.35	10.42	10.75	12.40	14.21	16.06	16.64	17.07	16.92	15.30	12.45	10.80
Colorado	7.45	7.55	7.81	8.05	8.98	11.46	11.58	12.26	11.32	8.94	8.06	7.62
Idaho, Montana, Utah, Wyoming	8.25	8.29	8.41	8.23	8.64	9.45	10.41	10.92	10.15	8.71	8.55	8.39
Arizona	12.61	13.03	13.51	14.89	16.67	18.49	20.15	20.85	20.17	18.71	15.80	13.62
Nevada, New Mexico	8.40	8.58	8.75	9.53	11.56	14.09	13.33	13.73	13.21	11.18	9.11	8.36
California	10.07	9.95	9.61	9.67	10.11	10.61	10.65	10.50	10.21	10.27	9.88	9.92
Oregon, Washington	10.89	11.05	11.09	11.42	11.95	12.63	13.65	14.19	13.77	12.35	11.53	11.25
Alaska	8.36	8.44	8.46	8.57	9.00	9.32	10.02	9.80	9.07	8.64	8.36	8.68
Hawaii	46.03	47.27	47.27	47.30	47.84	48.29	49.46	50.59	50.46	50.29	49.56	48.68
West Virginia	10.04	10.10	10.21	10.58	11.79	14.35	15.95	15.77	14.37	11.70	10.66	10.33
United States	9.99	10.04	10.18	10.72	11.83	13.33	14.14	14.42	13.79	11.82	10.68	10.19

Table 8D.3.39 Commercial Average Monthly Natural Gas Prices for 2013 Using Price Factors by CBECS 2003 Regions (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	11.37	11.41	11.45	11.20	10.40	10.21	10.59	10.48	10.34	10.04	11.10	11.57
Middle Atlantic	9.14	9.00	8.73	8.54	8.44	8.27	7.98	7.76	7.86	8.07	8.54	8.95
East North Central	7.16	7.06	7.12	7.24	7.62	8.16	8.44	8.38	7.90	7.15	7.27	7.19
West North Central	7.01	6.89	6.89	6.71	7.09	7.39	7.55	7.54	7.25	6.62	6.98	6.97
South Atlantic	9.73	9.73	9.54	9.67	9.87	10.17	10.23	10.01	10.04	9.83	9.71	9.73
East South Central	8.27	8.30	8.23	8.42	8.54	8.86	9.04	9.17	8.92	8.82	8.67	8.57
West South Central	7.92	7.70	7.50	7.50	7.83	7.88	7.91	7.77	7.78	8.02	8.28	8.06
Mountain	7.07	7.05	7.14	7.10	7.34	7.64	7.90	8.04	7.80	7.33	7.20	7.10
Pacific	8.47	8.46	8.44	8.34	8.37	8.43	8.56	8.77	8.63	8.47	8.55	8.59
United States	7.89	7.88	7.84	7.85	7.92	8.03	8.02	7.92	7.89	7.75	7.88	7.93

Table 8D.3.40 Residential Average Monthly LPG Prices for 2013 Using Monthly Price Factors by RECS 2009 Regions (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	29.65	29.95	30.11	30.13	30.60	30.90	31.00	30.81	30.78	30.92	30.61	30.59
Massachusetts	32.07	32.40	32.57	32.59	33.10	33.42	33.53	33.32	33.30	33.45	33.11	33.09
New York	31.21	31.53	31.70	31.72	32.21	32.53	32.63	32.43	32.41	32.55	32.23	32.20
New Jersey	31.84	32.17	32.34	32.36	32.86	33.19	33.29	33.09	33.06	33.21	32.88	32.85
Pennsylvania	29.14	29.44	29.59	29.61	30.07	30.37	30.47	30.28	30.25	30.39	30.08	30.06
Illinois	23.78	23.78	23.49	23.12	22.84	22.04	21.38	21.32	21.81	22.46	23.48	24.52
Indiana, Ohio	28.14	28.13	27.79	27.36	27.02	26.07	25.29	25.22	25.80	26.57	27.78	29.01
Michigan	25.75	25.74	25.43	25.04	24.73	23.86	23.15	23.08	23.62	24.32	25.42	26.55
Wisconsin	23.70	23.69	23.41	23.04	22.76	21.96	21.30	21.24	21.73	22.38	23.40	24.43
Iowa, Minnesota, North Dakota, South Dakota	24.27	24.26	23.97	23.60	23.31	22.49	21.82	21.75	22.26	22.92	23.96	25.02
Kansas, Nebraska	23.93	23.93	23.64	23.27	22.98	22.18	21.51	21.45	21.95	22.60	23.63	24.67
Missouri	24.32	24.32	24.02	23.65	23.36	22.54	21.86	21.80	22.31	22.97	24.01	25.08
Virginia	24.81	24.89	24.52	24.04	23.66	23.22	22.69	22.26	22.81	23.76	24.50	25.29
Delaware, District of Columbia, Maryland	34.63	34.74	34.22	33.56	33.03	32.40	31.66	31.06	31.84	33.16	34.19	35.30
Georgia	26.29	26.37	25.98	25.48	25.07	24.60	24.04	23.58	24.17	25.18	25.96	26.80
North Carolina, South Carolina	27.65	27.74	27.32	26.79	26.37	25.87	25.28	24.80	25.42	26.48	27.30	28.19
Florida	28.16	28.25	27.83	27.29	26.86	26.35	25.75	25.26	25.89	26.97	27.80	28.71
Alabama, Kentucky, Mississippi	24.60	24.68	24.31	23.84	23.46	23.02	22.49	22.07	22.62	23.56	24.29	25.08
Tennessee	30.03	30.13	29.67	29.10	28.64	28.10	27.46	26.94	27.61	28.76	29.65	30.61
Arkansas, Louisiana, Oklahoma	16.80	16.85	16.60	16.28	16.02	15.72	15.36	15.07	15.45	16.09	16.59	17.12
Texas	15.11	15.15	14.93	14.64	14.41	14.13	13.81	13.55	13.89	14.46	14.91	15.40
Colorado	26.49	26.54	26.09	25.49	24.88	24.17	23.30	23.00	23.91	25.34	26.16	27.18
Idaho, Montana, Utah, Wyoming	24.97	25.01	24.58	24.02	23.45	22.78	21.95	21.68	22.53	23.88	24.65	25.61
Arizona	31.48	31.54	31.00	30.29	29.56	28.72	27.68	27.33	28.41	30.11	31.08	32.29
Nevada, New Mexico	21.89	21.93	21.56	21.07	20.56	19.97	19.25	19.01	19.76	20.94	21.62	22.46
California	29.65	29.71	29.20	28.53	27.85	27.05	26.08	25.75	26.77	28.37	29.28	30.42
Oregon, Washington	27.67	27.72	27.25	26.63	25.99	25.24	24.33	24.03	24.98	26.47	27.32	28.39
Alaska	27.84	27.89	27.41	26.79	26.14	25.39	24.48	24.17	25.13	26.63	27.49	28.56
Hawaii	34.79	34.85	34.26	33.48	32.67	31.74	30.59	30.21	31.40	33.28	34.35	35.69
West Virginia	32.65	32.75	32.26	31.64	31.14	30.55	29.85	29.29	30.02	31.27	32.24	33.28
United States	18.31	18.42	18.30	18.17	18.19	17.82	17.02	16.63	17.14	17.69	18.26	18.81

Table 8D.3.41 Commercial Average Monthly LPG Prices for 2013 Using Monthly Price Factors by CBECS 2003 Regions (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	23.94	24.18	24.31	24.33	24.70	24.95	25.03	24.87	24.86	24.97	24.72	24.70
Middle Atlantic	23.75	23.99	24.12	24.14	24.51	24.75	24.83	24.68	24.66	24.77	24.52	24.50
East North Central	21.87	21.86	21.60	21.26	21.00	20.26	19.66	19.60	20.05	20.65	21.59	22.54
West North Central	21.96	21.95	21.68	21.35	21.08	20.34	19.74	19.68	20.13	20.73	21.67	22.63
South Atlantic	23.56	23.64	23.28	22.83	22.47	22.05	21.54	21.14	21.66	22.56	23.26	24.02
East South Central	22.10	22.17	21.83	21.41	21.07	20.68	20.20	19.82	20.32	21.16	21.82	22.52
West South Central	22.94	23.02	22.67	22.23	21.88	21.47	20.98	20.58	21.09	21.97	22.65	23.39
Mountain	21.83	21.87	21.49	21.00	20.50	19.91	19.19	18.95	19.70	20.88	21.55	22.39
Pacific	22.95	22.99	22.60	22.08	21.55	20.94	20.18	19.93	20.72	21.95	22.66	23.54
United States	22.07	22.21	22.06	21.91	21.93	21.48	20.52	20.05	20.66	21.32	22.01	22.68

Table 8D.3.42 Residential Average Monthly Oil Prices for 2013 Using Monthly Price Factors by RECS 2009 Regions (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	27.60	28.01	27.81	27.57	27.40	27.22	26.79	26.75	27.60	28.31	28.78	29.08
Massachusetts	28.43	28.85	28.65	28.40	28.23	28.03	27.59	27.55	28.43	29.16	29.64	29.96
New York	28.53	28.95	28.75	28.50	28.33	28.13	27.69	27.65	28.53	29.26	29.75	30.06
New Jersey	29.36	29.79	29.58	29.33	29.15	28.95	28.49	28.46	29.36	30.11	30.61	30.94
Pennsylvania	29.09	29.51	29.31	29.06	28.88	28.68	28.23	28.19	29.09	29.83	30.33	30.65
Illinois	27.47	27.78	28.16	28.34	28.30	28.23	28.05	28.67	29.69	30.33	30.28	29.81
Indiana, Ohio	27.38	27.69	28.07	28.25	28.21	28.14	27.96	28.57	29.59	30.23	30.18	29.71
Michigan	27.40	27.71	28.10	28.27	28.23	28.16	27.98	28.60	29.61	30.25	30.21	29.73
Wisconsin	27.15	27.46	27.84	28.01	27.97	27.90	27.72	28.33	29.34	29.97	29.93	29.46
Iowa, Minnesota, North Dakota, South Dakota	27.51	27.82	28.20	28.38	28.34	28.27	28.09	28.71	29.73	30.37	30.33	29.85
Kansas, Nebraska	27.35	27.66	28.04	28.22	28.18	28.11	27.93	28.54	29.56	30.20	30.15	29.68
Missouri	26.95	27.25	27.63	27.80	27.76	27.69	27.51	28.12	29.12	29.75	29.71	29.24
Virginia	28.55	28.87	28.74	28.35	27.49	27.13	27.16	27.42	28.43	29.19	29.73	30.04
Delaware, District of Columbia, Maryland	29.31	29.63	29.50	29.10	28.21	27.85	27.88	28.15	29.18	29.97	30.52	30.84
Georgia	28.28	28.59	28.46	28.08	27.22	26.87	26.89	27.16	28.16	28.91	29.44	29.75
North Carolina, South Carolina	28.52	28.83	28.70	28.32	27.45	27.10	27.12	27.39	28.40	29.16	29.69	30.00
Florida	28.82	29.13	29.00	28.62	27.74	27.38	27.41	27.68	28.69	29.46	30.00	30.32
Alabama, Kentucky, Mississippi	28.40	28.71	28.58	28.20	27.34	26.98	27.01	27.27	28.28	29.03	29.57	29.88
Tennessee	29.09	29.41	29.28	28.89	28.01	27.64	27.67	27.94	28.97	29.75	30.29	30.61
Arkansas, Louisiana, Oklahoma	26.57	26.86	26.74	26.38	25.58	25.25	25.27	25.52	26.46	27.17	27.66	27.95
Texas	26.84	27.13	27.01	26.65	25.83	25.50	25.52	25.78	26.72	27.44	27.94	28.23
Colorado	23.82	24.23	25.30	25.75	25.70	25.61	25.21	25.26	26.12	26.54	26.52	25.91
Idaho, Montana, Utah, Wyoming	23.84	24.25	25.33	25.77	25.73	25.64	25.24	25.29	26.14	26.57	26.55	25.94
Arizona	27.62	28.10	29.34	29.86	29.81	29.70	29.24	29.30	30.29	30.78	30.76	30.05
Nevada, New Mexico	25.42	25.86	27.00	27.48	27.43	27.33	26.91	26.96	27.87	28.32	28.31	27.66
California	28.01	28.49	29.76	30.28	30.23	30.12	29.66	29.71	30.72	31.21	31.19	30.48
Oregon, Washington	27.54	28.02	29.26	29.77	29.72	29.61	29.16	29.21	30.20	30.69	30.67	29.97
Alaska	26.07	26.51	27.69	28.18	28.13	28.03	27.60	27.65	28.58	29.05	29.03	28.36
Hawaii	27.10	27.57	28.79	29.30	29.25	29.14	28.69	28.74	29.72	30.20	30.18	29.49
West Virginia	28.82	29.13	29.00	28.62	27.74	27.38	27.41	27.68	28.69	29.46	30.00	30.32
United States	28.46	28.86	28.74	28.54	28.30	28.06	27.67	27.72	28.65	29.37	29.82	30.05

Table 8D.3.43 Commercial Average Monthly Oil Prices for 2013 Using Monthly Price Factors by CBECS 2003 Regions (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	27.94	28.35	28.16	27.92	27.74	27.55	27.12	27.08	27.95	28.66	29.13	29.45
Middle Atlantic	28.84	29.26	29.06	28.81	28.63	28.44	27.99	27.95	28.84	29.58	30.07	30.39
East North Central	27.36	27.67	28.05	28.23	28.18	28.11	27.93	28.55	29.57	30.20	30.16	29.69
West North Central	27.46	27.77	28.16	28.33	28.29	28.22	28.04	28.66	29.68	30.32	30.28	29.80
South Atlantic	29.10	29.42	29.29	28.90	28.02	27.65	27.68	27.95	28.98	29.76	30.30	30.62
East South Central	28.75	29.07	28.94	28.55	27.68	27.32	27.35	27.62	28.63	29.40	29.94	30.25
West South Central	26.68	26.98	26.86	26.50	25.69	25.35	25.38	25.63	26.57	27.28	27.78	28.07
Mountain	24.14	24.55	25.64	26.09	26.05	25.95	25.55	25.60	26.47	26.89	26.88	26.26
Pacific	27.48	27.95	29.19	29.71	29.66	29.55	29.09	29.15	30.13	30.62	30.60	29.90
United States	28.46	28.86	28.74	28.54	28.30	28.06	27.67	27.72	28.65	29.37	29.82	30.05

8D.3.5.2 Marginal Monthly Energy Prices

Table 8D.3.44 Residential Marginal Monthly Electricity Prices for 2013 Using Marginal Price Factors by RECS 2009 Regions (2014$/kWh)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	0.150	0.151	0.153	0.149	0.150	0.150	0.149	0.149	0.149	0.151	0.154	0.153
Massachusetts	0.156	0.157	0.157	0.143	0.145	0.149	0.145	0.146	0.148	0.146	0.158	0.162
New York	0.157	0.159	0.159	0.202	0.206	0.214	0.217	0.217	0.216	0.210	0.164	0.161
New Jersey	0.141	0.142	0.143	0.174	0.178	0.192	0.197	0.197	0.192	0.177	0.145	0.145
Pennsylvania	0.096	0.097	0.098	0.131	0.136	0.141	0.141	0.140	0.138	0.136	0.101	0.099
Illinois	0.066	0.069	0.071	0.100	0.104	0.105	0.104	0.103	0.103	0.103	0.071	0.067
Indiana, Ohio	0.077	0.079	0.082	0.120	0.124	0.126	0.123	0.123	0.124	0.123	0.086	0.080
Michigan	0.131	0.132	0.131	0.156	0.159	0.164	0.166	0.167	0.163	0.158	0.133	0.134
Wisconsin	0.112	0.116	0.114	0.134	0.136	0.137	0.134	0.135	0.136	0.136	0.117	0.115
Iowa, Minnesota, North Dakota, South Dakota	0.086	0.088	0.089	0.119	0.124	0.129	0.130	0.129	0.126	0.122	0.092	0.089
Kansas, Nebraska	0.066	0.069	0.071	0.123	0.128	0.142	0.143	0.143	0.142	0.127	0.074	0.070
Missouri	0.066	0.068	0.071	0.121	0.137	0.149	0.147	0.146	0.133	0.123	0.073	0.069
Virginia	0.080	0.082	0.084	0.114	0.119	0.121	0.122	0.122	0.119	0.116	0.086	0.082
Delaware, District of Columbia, Maryland	0.107	0.107	0.109	0.141	0.154	0.166	0.164	0.164	0.161	0.148	0.112	0.110
Georgia	0.084	0.087	0.090	0.126	0.131	0.141	0.143	0.144	0.138	0.129	0.089	0.085
North Carolina, South Carolina	0.084	0.086	0.087	0.106	0.106	0.104	0.107	0.107	0.108	0.111	0.090	0.086
Florida	0.101	0.102	0.103	0.112	0.110	0.110	0.110	0.111	0.111	0.112	0.105	0.103
Alabama, Kentucky, Mississippi	0.076	0.078	0.080	0.096	0.098	0.098	0.096	0.097	0.097	0.099	0.083	0.079
Tennessee	0.079	0.080	0.081	0.092	0.093	0.092	0.091	0.091	0.091	0.095	0.086	0.083
Arkansas, Louisiana, Oklahoma	0.069	0.071	0.073	0.094	0.096	0.098	0.098	0.099	0.100	0.100	0.074	0.071
Texas	0.092	0.093	0.096	0.113	0.115	0.119	0.119	0.119	0.118	0.118	0.098	0.096
Colorado	0.087	0.089	0.089	0.127	0.130	0.132	0.131	0.132	0.132	0.130	0.092	0.089
Idaho, Montana, Utah, Wyoming	0.087	0.088	0.088	0.100	0.104	0.107	0.108	0.107	0.107	0.107	0.090	0.089
Arizona	0.083	0.086	0.088	0.116	0.128	0.127	0.126	0.125	0.125	0.124	0.088	0.089
Nevada, New Mexico	0.096	0.098	0.099	0.126	0.128	0.129	0.130	0.131	0.129	0.131	0.100	0.099
California	0.174	0.170	0.169	0.182	0.188	0.193	0.197	0.196	0.189	0.180	0.175	0.177
Oregon, Washington	0.079	0.080	0.080	0.073	0.073	0.074	0.075	0.075	0.075	0.075	0.082	0.082
Alaska	0.151	0.153	0.156	0.150	0.154	0.154	0.157	0.155	0.152	0.153	0.159	0.157
Hawaii	0.333	0.334	0.333	0.474	0.482	0.488	0.492	0.496	0.495	0.503	0.356	0.354
West Virginia	0.075	0.076	0.078	0.086	0.089	0.087	0.086	0.086	0.088	0.090	0.080	0.077
United States	0.092	0.094	0.096	0.125	0.128	0.131	0.131	0.132	0.131	0.129	0.099	0.096

Table 8D.3.45 Commercial Marginal Monthly Electricity Prices for 2013 Using Marginal Price Factors by CBECS 2003 Regions (2014$/kWh)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	0.123	0.126	0.124	0.145	0.144	0.152	0.152	0.151	0.153	0.148	0.124	0.127
Middle Atlantic	0.120	0.120	0.120	0.184	0.189	0.203	0.210	0.208	0.205	0.196	0.122	0.122
East North Central	0.067	0.068	0.069	0.105	0.107	0.109	0.109	0.109	0.108	0.108	0.069	0.068
West North Central	0.053	0.055	0.055	0.131	0.137	0.147	0.150	0.149	0.141	0.132	0.056	0.055
South Atlantic	0.109	0.111	0.111	0.108	0.115	0.125	0.125	0.125	0.123	0.114	0.113	0.112
East South Central	0.064	0.065	0.066	0.094	0.094	0.095	0.093	0.094	0.093	0.094	0.067	0.066
West South Central	0.041	0.042	0.042	0.089	0.089	0.090	0.090	0.090	0.090	0.090	0.041	0.041
Mountain	0.089	0.092	0.092	0.106	0.108	0.110	0.108	0.108	0.109	0.110	0.095	0.092
Pacific	0.079	0.080	0.079	0.102	0.102	0.104	0.106	0.105	0.106	0.107	0.082	0.081
United States	0.076	0.077	0.077	0.130	0.133	0.138	0.140	0.140	0.138	0.136	0.078	0.077

Table 8D.3.46 Residential Marginal Monthly Natural Gas Prices for 2013 Using Marginal Price Factors by RECS 2009 Regions (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	13.04	13.12	13.31	11.58	12.12	13.16	14.68	15.03	14.48	12.83	14.05	13.68
Massachusetts	14.33	14.32	14.21	12.26	11.64	11.93	13.17	13.86	13.38	11.57	14.65	14.56
New York	11.32	11.13	11.30	9.78	10.89	12.45	13.11	12.33	12.09	10.63	11.33	10.61
New Jersey	10.46	10.34	10.37	8.95	9.52	10.45	10.90	10.85	10.70	9.87	10.98	10.65
Pennsylvania	10.54	10.65	10.85	8.66	9.75	11.31	12.54	12.88	12.20	9.97	11.45	10.83
Illinois	8.01	8.04	8.12	5.93	7.24	8.38	9.02	9.11	8.47	6.60	8.50	7.98
Indiana, Ohio	9.45	9.53	9.80	7.80	8.77	10.23	11.20	11.39	10.64	8.47	9.96	9.68
Michigan	8.35	8.37	8.48	7.12	7.96	9.10	10.07	10.40	9.59	7.96	8.99	8.67
Wisconsin	9.01	8.79	8.97	7.29	7.26	8.40	8.73	8.87	8.11	6.61	9.24	8.99
Iowa, Minnesota, North Dakota, South Dakota	8.29	8.14	8.28	6.14	6.98	8.24	8.86	9.13	8.52	6.77	8.69	8.27
Kansas, Nebraska	8.72	8.77	8.76	6.80	7.62	9.08	9.85	10.32	10.01	8.53	9.67	9.01
Missouri	8.93	8.94	9.07	7.18	8.32	10.29	11.80	12.48	11.63	9.83	10.82	9.52
Virginia	11.18	10.72	10.60	8.27	9.79	11.44	12.38	12.17	12.14	9.82	11.47	11.10
Delaware, District of Columbia, Maryland	10.53	10.40	10.66	8.42	9.71	11.07	11.84	11.82	11.37	9.20	11.23	10.72
Georgia	10.87	11.58	12.09	8.46	10.50	11.82	12.46	12.35	11.99	10.28	12.44	11.65
North Carolina, South Carolina	11.23	11.14	11.54	8.81	10.26	12.32	13.00	13.50	12.91	10.63	12.32	11.98
Florida	12.75	13.03	13.90	11.56	12.60	13.41	13.85	14.15	13.95	13.72	16.00	14.20
Alabama, Kentucky, Mississippi	8.92	8.98	9.20	7.87	9.29	10.48	10.94	11.30	10.81	9.05	9.84	9.39
Tennessee	9.06	9.19	9.24	7.87	8.66	9.99	10.66	10.97	10.52	9.51	10.20	9.53
Arkansas, Louisiana, Oklahoma	8.38	8.33	8.53	7.02	8.27	8.99	9.40	9.54	9.34	9.02	10.39	9.00
Texas	8.69	8.75	9.02	7.29	8.35	9.44	9.78	10.03	9.94	8.99	10.46	9.06
Colorado	6.67	6.75	6.99	5.46	6.09	7.77	7.86	8.32	7.68	6.07	7.22	6.82
Idaho, Montana, Utah, Wyoming	7.75	7.78	7.89	6.85	7.19	7.86	8.67	9.09	8.44	7.25	8.02	7.87
Arizona	10.69	11.05	11.45	9.48	10.61	11.77	12.83	13.27	12.84	11.91	13.39	11.54
Nevada, New Mexico	7.63	7.79	7.94	6.39	7.75	9.44	8.94	9.20	8.85	7.49	8.27	7.59
California	10.90	10.78	10.41	8.04	8.41	8.82	8.86	8.73	8.49	8.54	10.70	10.74
Oregon, Washington	10.21	10.35	10.39	9.59	10.03	10.60	11.46	11.92	11.56	10.37	10.81	10.54
Alaska	8.20	8.28	8.30	7.44	7.82	8.10	8.70	8.51	7.87	7.50	8.20	8.51
Hawaii	46.84	48.10	48.11	36.59	37.01	37.36	38.27	39.14	39.04	38.91	50.44	49.54
West Virginia	9.60	9.66	9.76	8.27	9.22	11.22	12.47	12.33	11.24	9.15	10.20	9.88
United States	9.43	9.49	9.61	7.74	8.55	9.63	10.22	10.41	9.97	8.54	10.09	9.62

Table 8D.3.47 Commercial Marginal Monthly Natural Gas Prices for 2013 Using Marginal Price Factors by CBECS 2003 Regions (2014$/MMBtu)

Geographical Area	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
New England	11.33	11.38	11.42	11.37	10.57	10.37	10.76	10.64	10.51	10.20	11.07	11.53
Middle Atlantic	9.10	8.95	8.69	8.79	8.69	8.52	8.22	7.99	8.09	8.31	8.50	8.91
East North Central	7.09	6.99	7.04	5.83	6.14	6.57	6.80	6.74	6.36	5.76	7.19	7.12
West North Central	7.18	7.05	7.06	5.62	5.94	6.19	6.32	6.32	6.08	5.54	7.15	7.14
South Atlantic	9.21	9.21	9.04	8.73	8.91	9.18	9.24	9.03	9.07	8.87	9.19	9.21
East South Central	7.78	7.81	7.74	7.23	7.34	7.60	7.76	7.87	7.66	7.58	8.16	8.06
West South Central	7.41	7.21	7.02	5.80	6.05	6.09	6.12	6.01	6.02	6.21	7.75	7.54
Mountain	6.97	6.96	7.04	6.14	6.34	6.61	6.83	6.95	6.75	6.34	7.10	7.01
Pacific	8.77	8.76	8.73	7.77	7.79	7.86	7.98	8.18	8.04	7.89	8.85	8.89
United States	7.85	7.84	7.80	7.10	7.16	7.27	7.26	7.17	7.14	7.01	7.84	7.89

8D.4 HOUSEHOLD ENERGY PRICE ADJUSTMENT FACTOR

RECS 2009 reports the total annual consumption and expenditure of each energy use type. From this data DOE determined average energy prices per geographical area. To take into account that household energy prices vary inside a geographical area, DOE developed an adjustment factor based on the reported average energy price in RECS 2009 divided by the average energy price of the geographical region. This factor was then multiplied times the monthly marginal energy prices (for natural gas and electricity) or the monthly price developed above to determine the household energy price.

8D.5 NATURAL GAS TARIFF ANALYSIS

As described above, DOE developed marginal price factors to estimate marginal natural gas prices that were developed from EIA data, not directly from gas tariff documents. The Gas Technology Institute (GTI) submitted documents describing a total of 23 residential gas tariffs for 13 companies operating in multiple states.[9] DOE used this information to validate the residential natural gas marginal price factors presented in the previous section.

8D.5.1 Calculation Methodology

DOE used the following calculation approach to estimate the ratio of marginal to average prices, or the marginal price factors, for the 23 tariffs submitted by GTI.

Tariffs have one or more tiers. The simplest tariff structure consists of a monthly fixed cost (*FC*) and a commodity cost (*i.e.*, for units of gas) (*CC*). The total monthly bill (*MonthlyBill*) is:

$$MonthlyBill = FC + U \times CC$$

Eq. 8-D.5.1

Where:

FC = monthly fixed cost for natural gas,
U = monthly consumer natural gas usage, and
CC = commodity cost for natural gas.

The average monthly price (*AveragePrice*) is equal to the ratio of the monthly bill to the total monthly usage:

$$AveragePrice = \frac{MonthlyBill}{U} = \frac{FC}{U} + CC$$

Eq. 8-D.5.2

The marginal price is equal to the commodity cost *CC*; therefore, for this type of tariff, the average price exceeds the marginal price by the amount *FC*/*U*:

$$AveragePrice = MarginalPrice + \frac{FC}{U}$$

Eq. 8-D.5.3

Where:

MarginalPrice = marginal price, which is equal to the commodity cost *CC*.

The difference between the average and marginal prices decreases with customer usage *U*, and thus should be larger in the summer, when usage is lower. For tariffs with multiple tiers, the difference depends on tier in which the customer is.

To determine the marginal price factors for each season (summer or winter) ($MarginalPriceFactor_{Season}$) for each of the 23 tariffs, DOE calculated the ratio of the average monthly natural gas price to the marginal price:

$$MarginalPriceFactor_{Season} = \frac{AveragePrice_{Season}}{MarginalPrice_{Season}}$$

Eq. 8-D.5.4

Where:

Season = summer or winter.

8D.5.2 Data Inputs

DOE estimated the monthly usage *U* based on the RECS 2009 average annual natural gas consumption by RECS 2009 region. DOE used monthly natural gas consumption data from EIA's Natural Gas Navigator to allocate natural gas usage to summer and winter months. These data show that on average 70 percent of annual consumption occurs in the winter (the 5 months from November through March) and 30 percent during the rest of the year (the remaining 7 months). Hence, DOE defined summer monthly usage as:

$$Summer\ Monthly\ NG\ Usage = \frac{30\%\ of\ Annual\ NG\ Usage}{7\ summer\ months/year} \times Annual\ Average\ NG\ Usage$$

Eq. 8-D.5.5

and winter monthly usage as:

$$Winter\ Monthly\ NG\ Usage = \frac{70\%\ of\ Annual\ NG\ Usage}{5\ winter\ months/year} \times Annual\ Average\ NG\ Usage$$

Eq. 8-D.5.6

DOE obtained the fixed charges and commodity charges from the tariff documents submitted by GTI. Of these 23 tariffs, eight have more than one tier. For the eight tariffs with multiple tiers, DOE estimated the commodity cost as the average of the two-tier charges.

8D.5.3 Results

Table 8D.5.1 lists the marginal price factors for each of the 23 tariffs submitted by GTI. Table 8D.5.1 also includes the marginal price factors estimated from the EIA data for comparison, and the assumed monthly summer and winter natural gas usage in therms. The EIA data and usage estimates depend only on the region. In general, the tariff-based marginal price factors for winter are less than one, as expected.

The winter price factors used by DOE are generally slightly higher than those computed from the tariff data, indicating that DOE's marginal price estimates are reasonable at average usage levels. The summer factors, which are less relevant for analysis of boilers, are either slightly higher or about the same. Of the 23 tariffs analyzed, eight have multiple tiers, and of these eight, six have ascending rates and two have descending rates. Because this analysis uses an average of the two tiers as the commodity price, it will generally underestimate the marginal prices for consumers subject to the second tier.

A full tariff-based analysis would require information about the household's total baseline gas usage (to establish which tier the consumer is in), and a weight factor for each tariff that determines how many customers are served by that utility on that tariff. These data are generally not available in the public domain. DOE's use of EIA state-level data effectively averages over all consumer sales in each state, and so incorporates information about all utilities. DOE's

approach is therefore more likely to provide prices representative of a typical consumer than any individual tariff.

Table 8D.5.1 Tariff-Based (GTI) and EIA-Based Marginal Price Factors and Natural Gas Consumption by Season

Region ID	State	Summer		Winter		Natural Gas Consumption *Therms*	
		GTI	EIA	GTI	EIA	Summer	Winter
1	CT	0.54	0.82	0.79	0.91	33	109
1	CT	0.59	0.82	0.82	0.91	33	109
1	CT	0.74	0.82	0.90	0.91	33	109
5	PA	0.65	0.73	0.86	0.93	31	102
7	IA	0.61	0.73	0.84	0.92	37	120
10	MN	0.76	0.72	0.92	0.97	37	120
11	KS	0.56	0.69	0.81	0.93	33	107
13	VA	0.70	0.68	0.89	0.93	28	90
14	DC	0.60	0.70	0.83	0.92	27	90
14	DE	0.66	0.70	0.87	0.92	27	90
14	MD	0.73	0.70	0.91	0.92	27	90
14	MD	0.73	0.70	0.90	0.92	27	90
14	MD	0.72	0.70	0.89	0.92	27	90
22	CO	0.70	0.69	0.88	0.91	35	116
22	CO	0.67	0.69	0.87	0.91	35	116
22	CO	0.69	0.69	0.88	0.91	35	116
23	ID	0.88	0.84	0.96	0.96	34	110
23	ID	0.85	0.84	0.94	0.96	34	110
24	AZ	0.61	0.64	0.84	0.85	13	43
25	NV	0.68	0.72	0.87	0.89	23	74
26	CA	0.84	0.85	0.95	1.08	17	57
27	OR	0.80	0.84	0.93	0.94	32	105
27	WA	0.76	0.84	0.91	0.94	32	105

8D.6 ENERGY PRICE TRENDS

8D.6.1 Residential Energy Price Trends

DOE used *AEO 2015* Reference Case scenarios for the nine census divisions. DOE applied the projected energy price for each of the nine census divisions to each household in the sample based on the household's location.

To arrive at prices in future years, DOE multiplied the prices described in the preceding section by the forecast of annual average price changes in EIA's *AEO 2015*.[10] DOE converted the forecasted energy prices into energy price factors, with 2013 as the base year. Figure 8D.6.1 shows the national residential electricity price factor trend. To estimate the trend after 2040, DOE used the average rate of change during 2025–2040 for electricity, natural gas, LPG, and fuel oil.

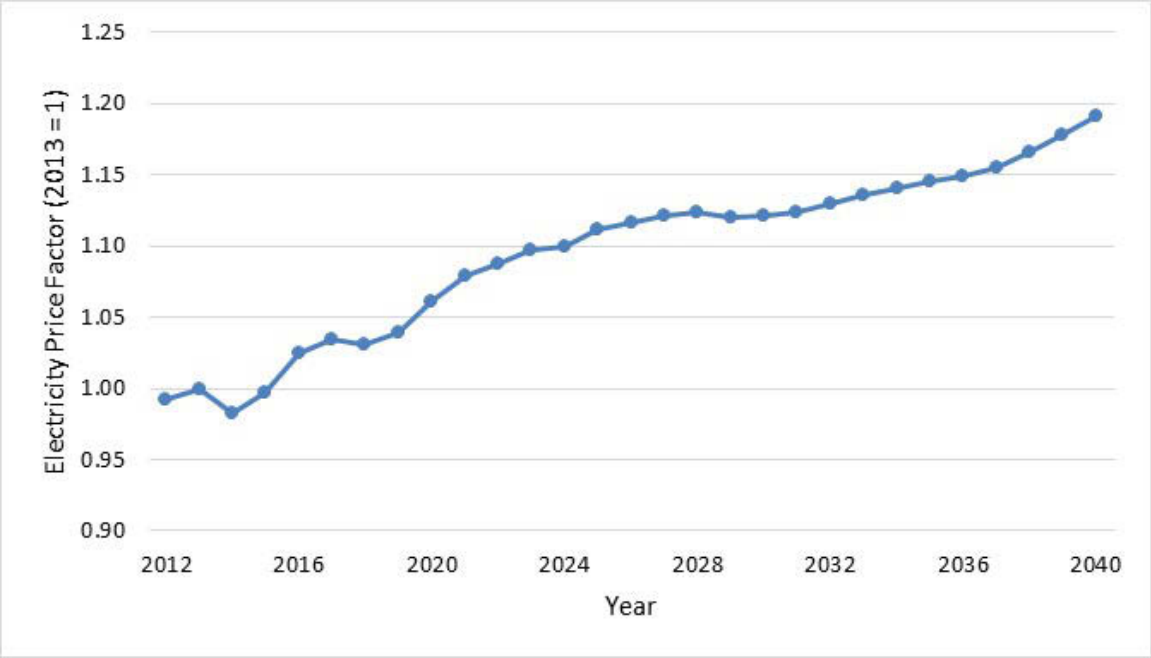

Figure 8D.6.1 Projected Residential National Electricity Price Factor

Figure 8D.6.2 shows the residential regional electricity price factor trends, disaggregated by the nine census divisions.

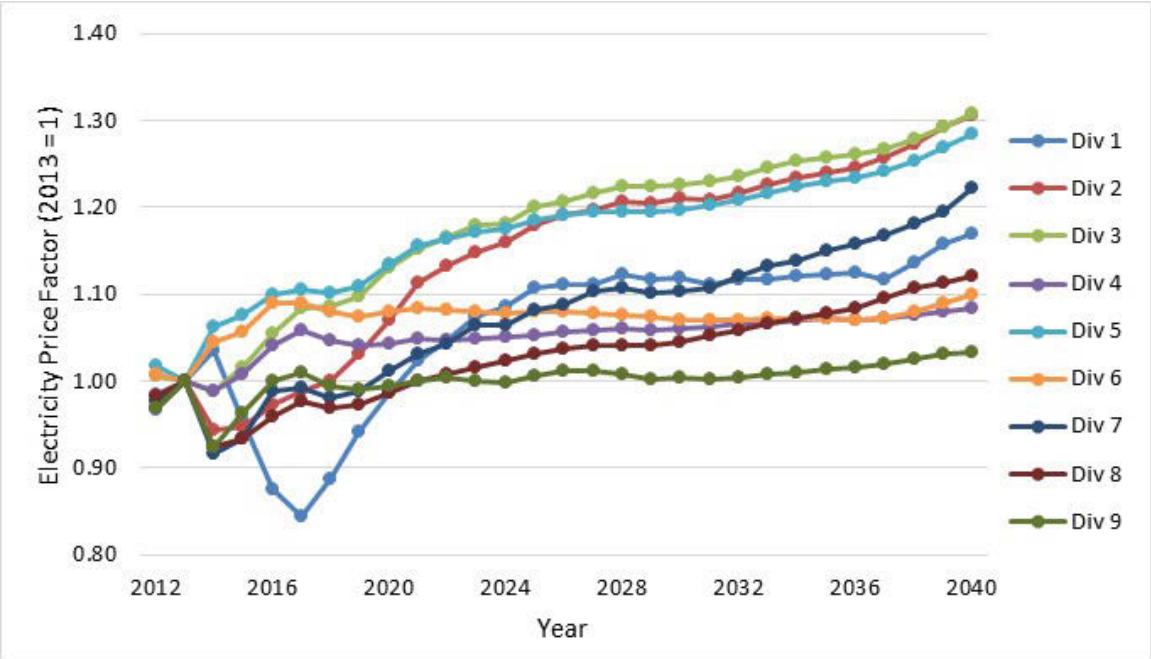

Figure 8D.6.2 Projected Residential Electricity Price Factors by Census Division

Figure 8D.6.3 shows the residential national natural gas price factor trend.

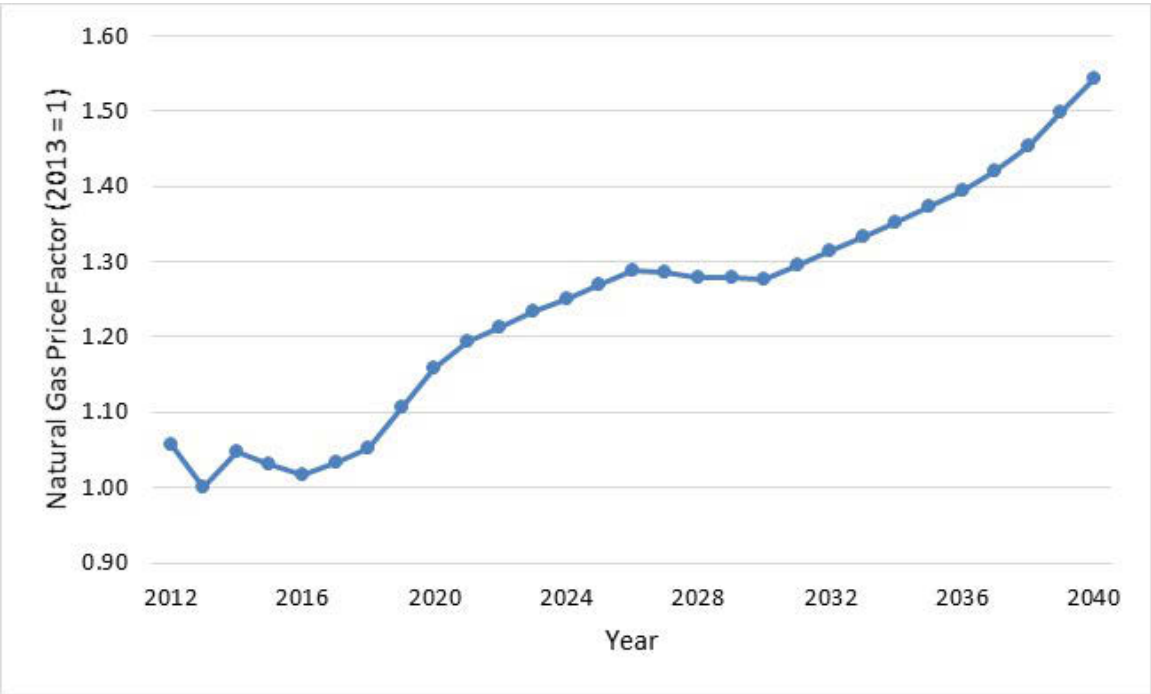

Figure 8D.6.3 Projected Residential National Natural Gas Price Factor

Figure 8D.6.4 shows the residential regional natural gas price factor trends, disaggregated by the nine census divisions.

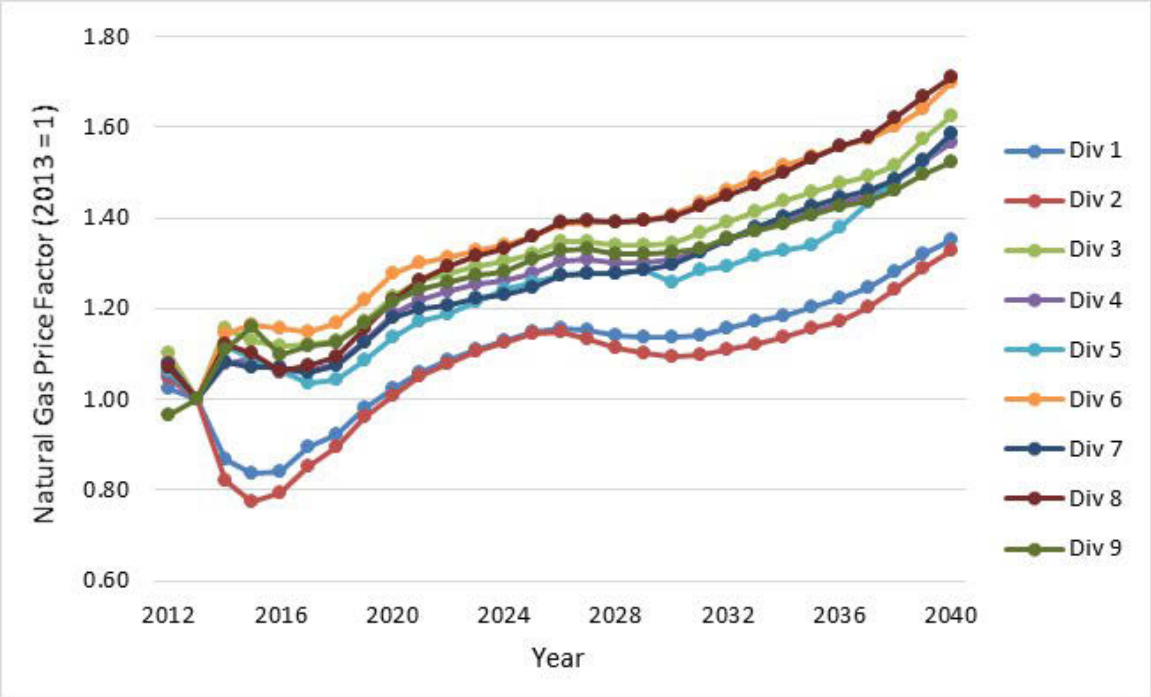

Figure 8D.6.4 Projected Residential Natural Gas Price Factors by Census Division

Figure 8D.6.5 shows the residential national LPG price factor trend.

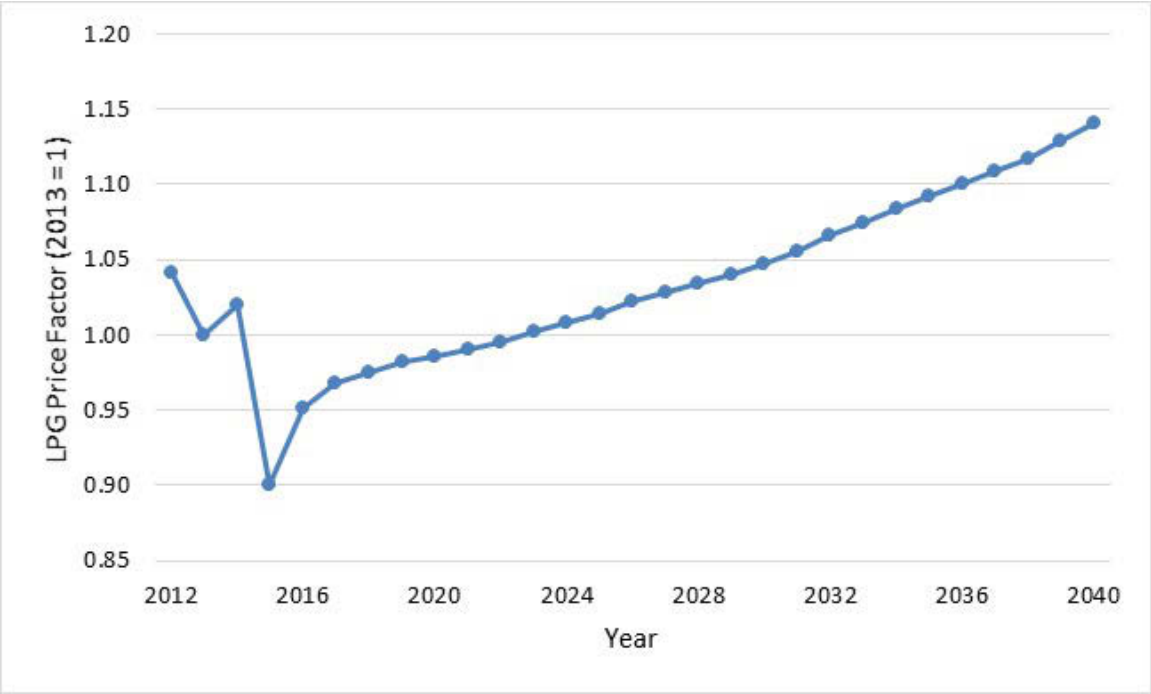

Figure 8D.6.5 Projected Residential National LPG Price Factor

Figure 8D.6.6 shows the residential regional LPG price factor trends, disaggregated by the nine census divisions.

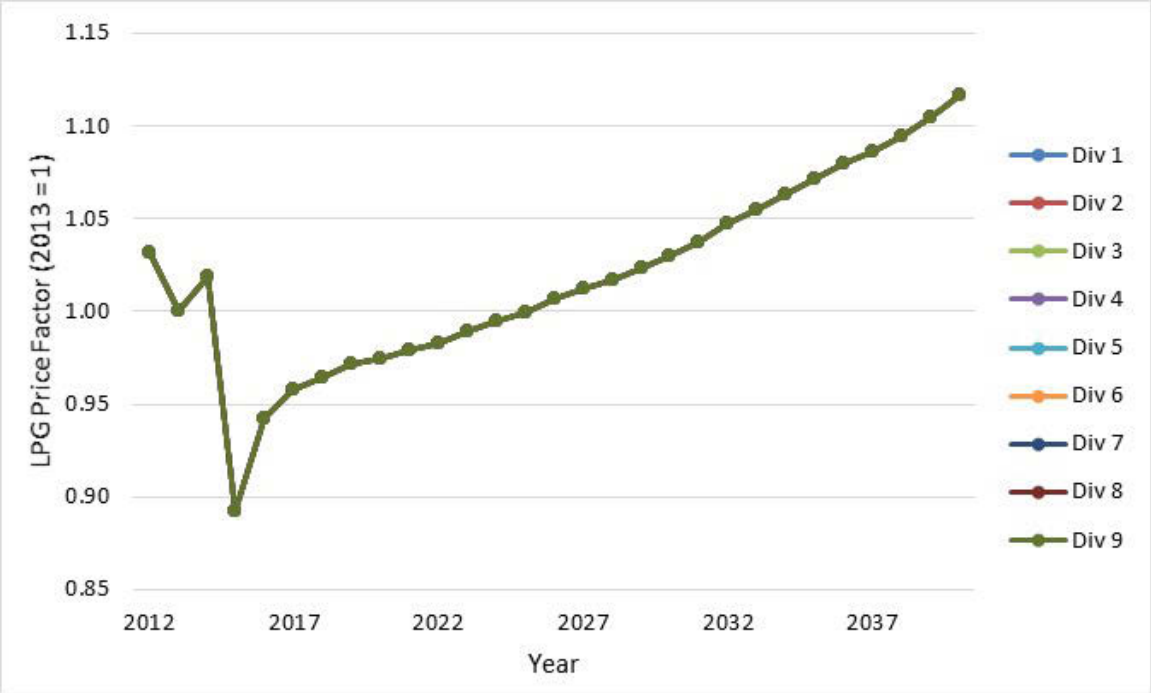

Figure 8D.6.6 Projected Residential LPG Price Factors by Census Division

Figure 8D.6.7 shows the residential national fuel oil price factor trend.

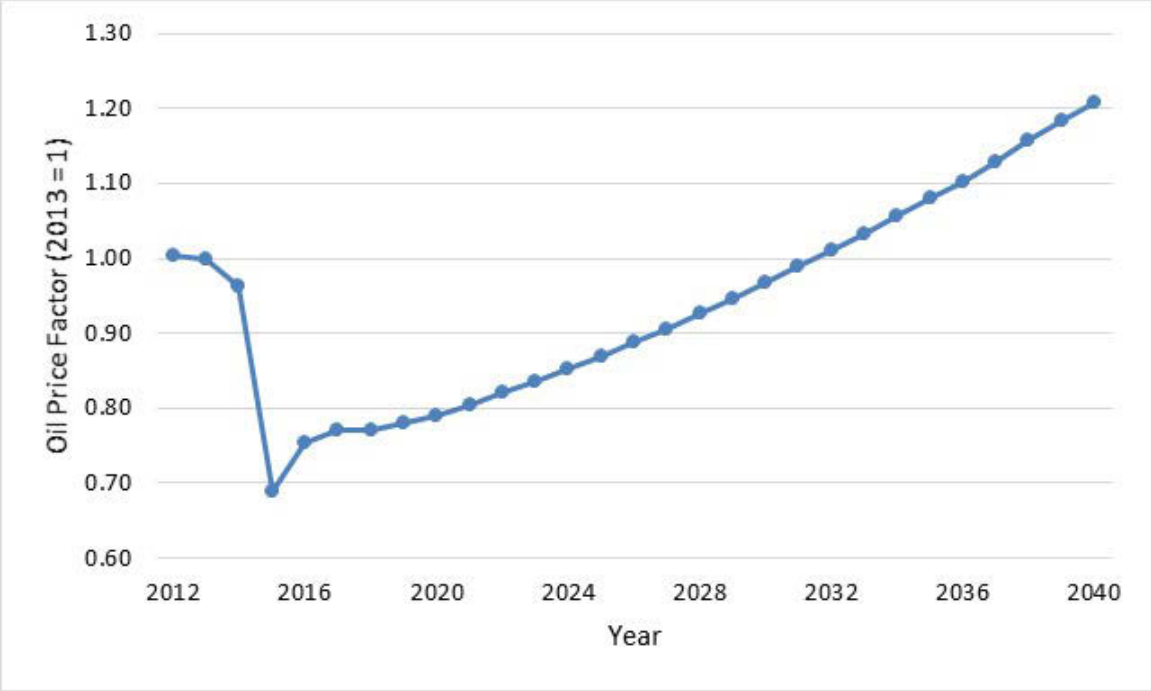

Figure 8D.6.7 Projected Residential National Fuel Oil Price Factor

Figure 8D.6.8 shows the residential regional fuel oil price factor trends, disaggregated by the nine census divisions.

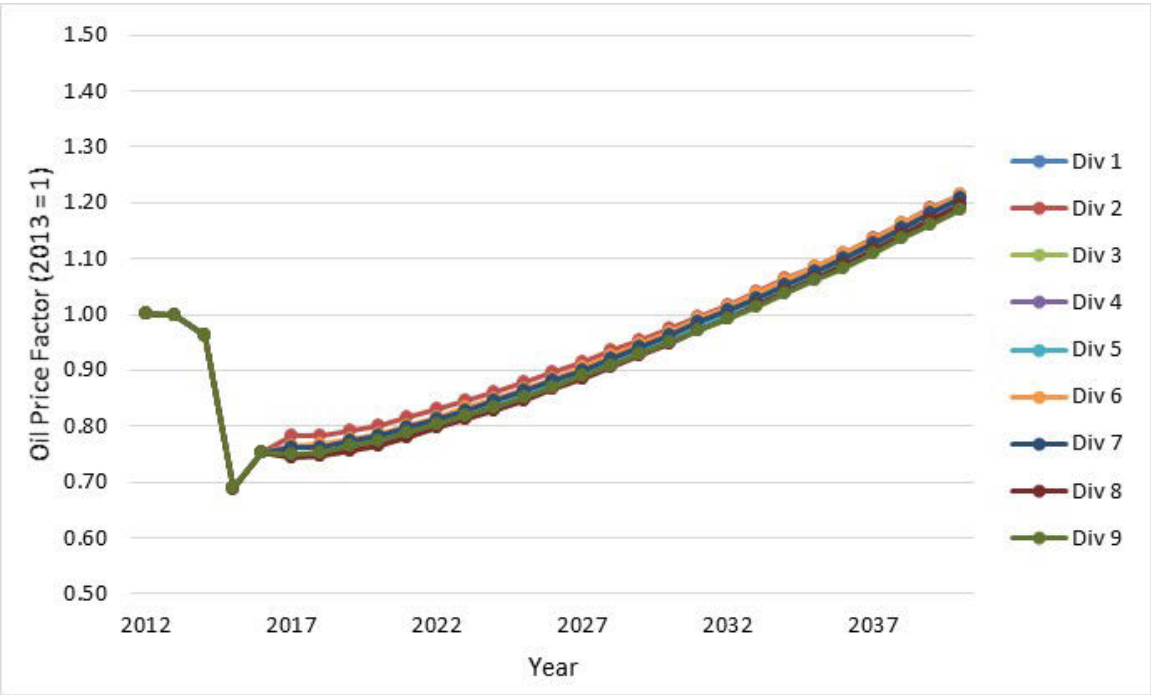

Figure 8D.6.8 Projected Residential Fuel Oil Price Factors by Census Division

8D.6.2 Commercial Energy Price Trends

DOE applied the same methodology to the projected energy price for each of the nine census divisions to each building in the commercial sample, based on the building's location.

To arrive at prices in future years, DOE multiplied the prices described in the preceding section by the forecast of annual average price changes in EIA's *AEO 2015.*[10] DOE converted the forecasted energy prices into energy price factors, with 2012 as the base year. Figure 8D.6.9 shows the national commercial electricity price factor trend. To estimate the trend after 2040, DOE followed past guidelines provided to the Federal Energy Management Program (FEMP) by EIA and used the average rate of change during 2020–2040 for electricity, natural gas, LPG, and fuel oil.

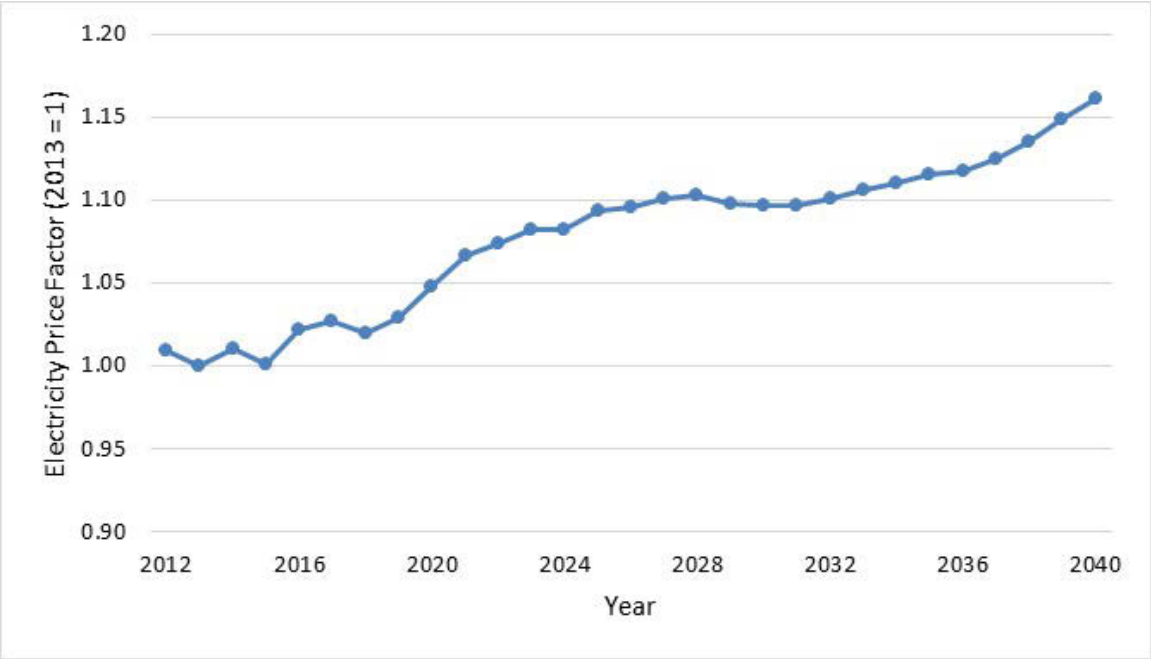

Figure 8D.6.9 Projected Commercial National Electricity Price Factor

Figure 8D.6.10 shows the commercial regional electricity price factor trends, disaggregated by the nine census divisions.

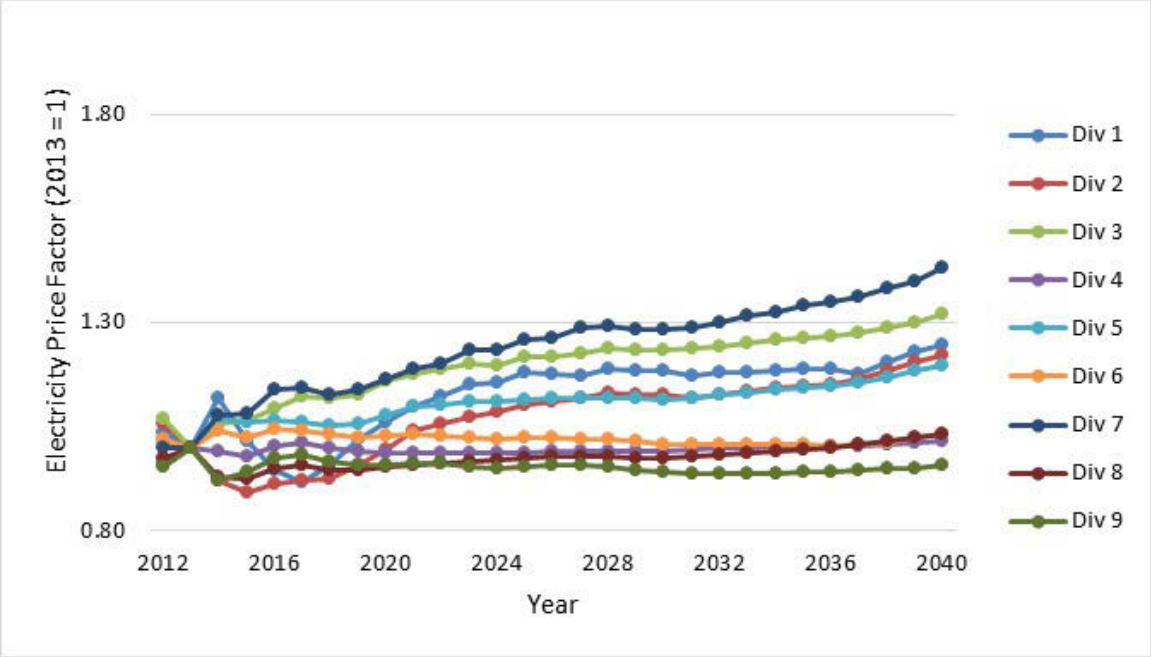

Figure 8D.6.10 Projected Commercial Electricity Price Factors by Census Division

Figure 8D.6.11 shows the commercial national natural gas price factor trend.

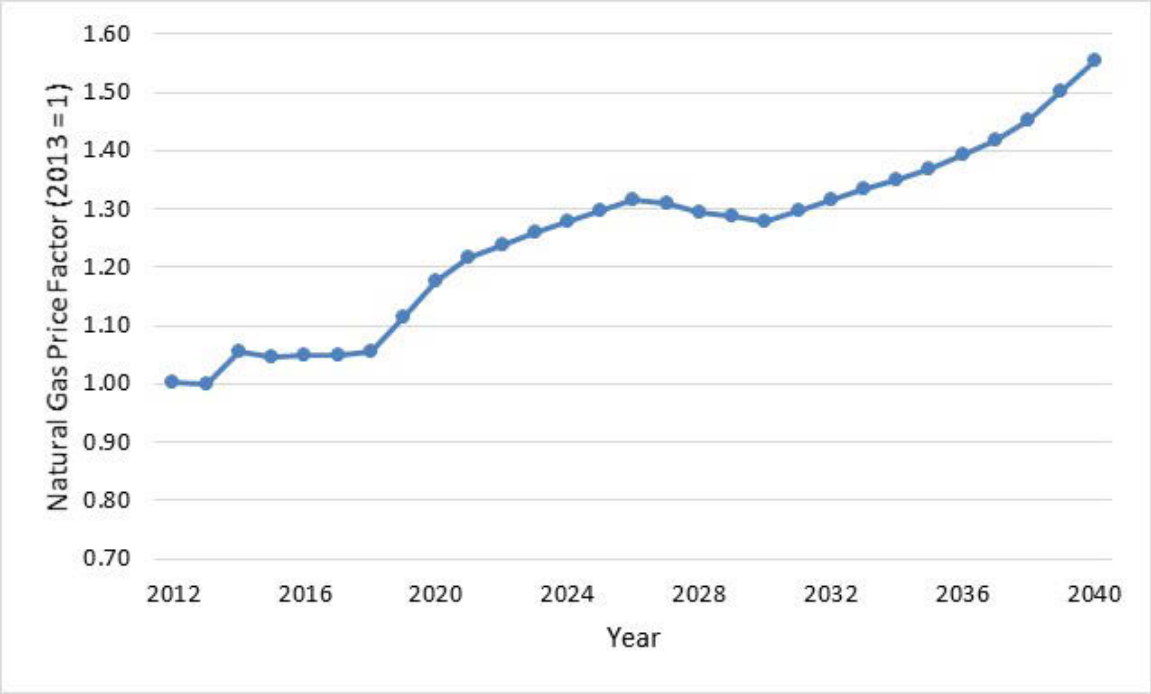

Figure 8D.6.11 Projected Commercial National Natural Gas Price Factor

Figure 8D.6.12 shows the commercial regional natural gas price factor trends, disaggregated by the nine census divisions.

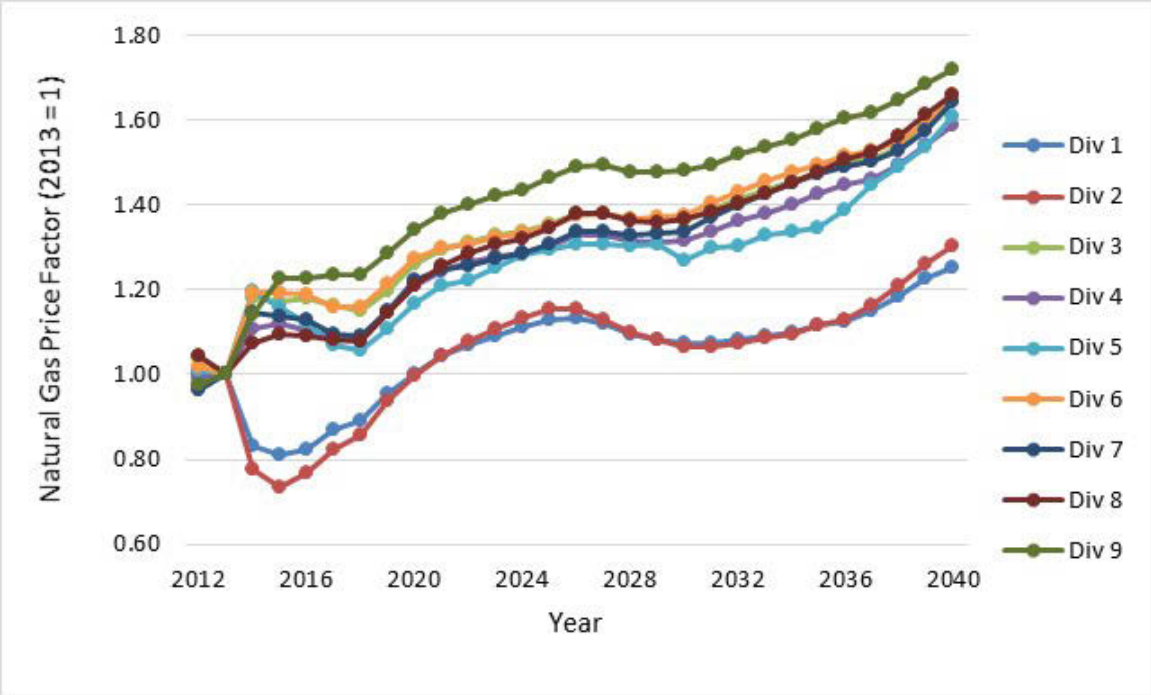

Figure 8D.6.12 Projected Commercial Natural Gas Price Factors by Census Division

Figure 8D.6.13 shows the commercial national LPG price factor trend.

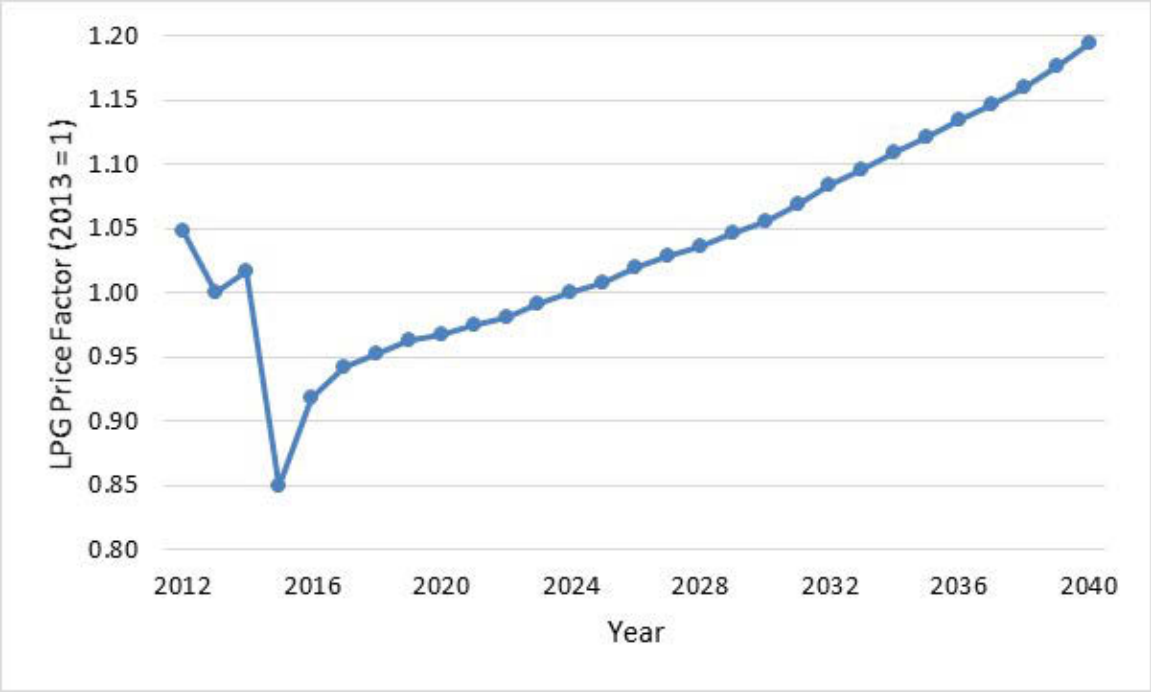

Figure 8D.6.13 Projected Commercial National LPG Prices

Figure 8D.6.14 shows the commercial regional LPG price factor trends, disaggregated by the nine census divisions.

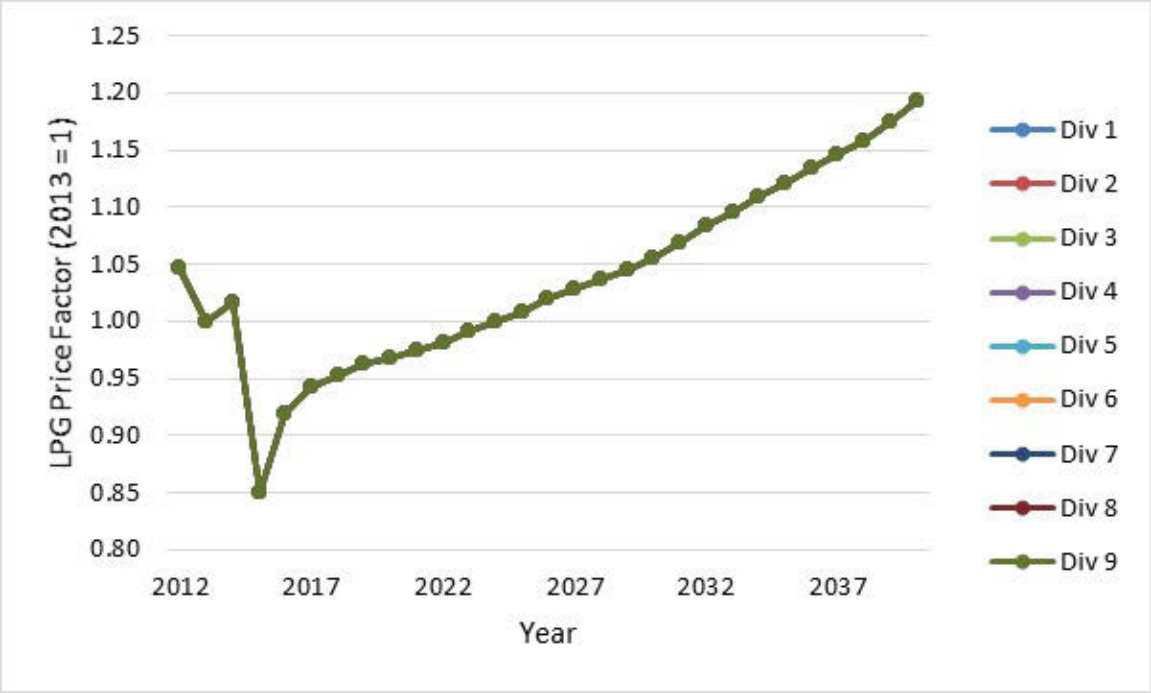

Figure 8D.6.14 Projected Commercial LPG Price Factors by Census Division

Figure 8D.6.15 shows the commercial national fuel oil price factor trend.

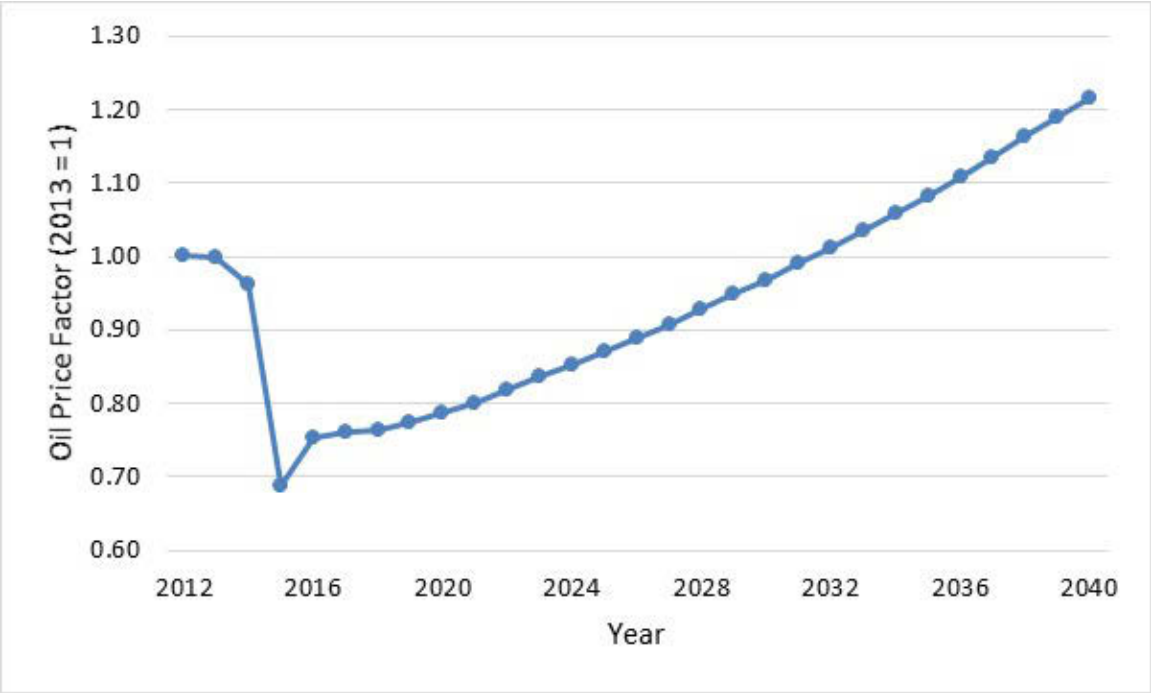

Figure 8D.6.15 Projected Commercial National Fuel Oil Price Factor

Figure 8D.6.16 shows the commercial regional fuel oil price factor trends, disaggregated by the nine census divisions.

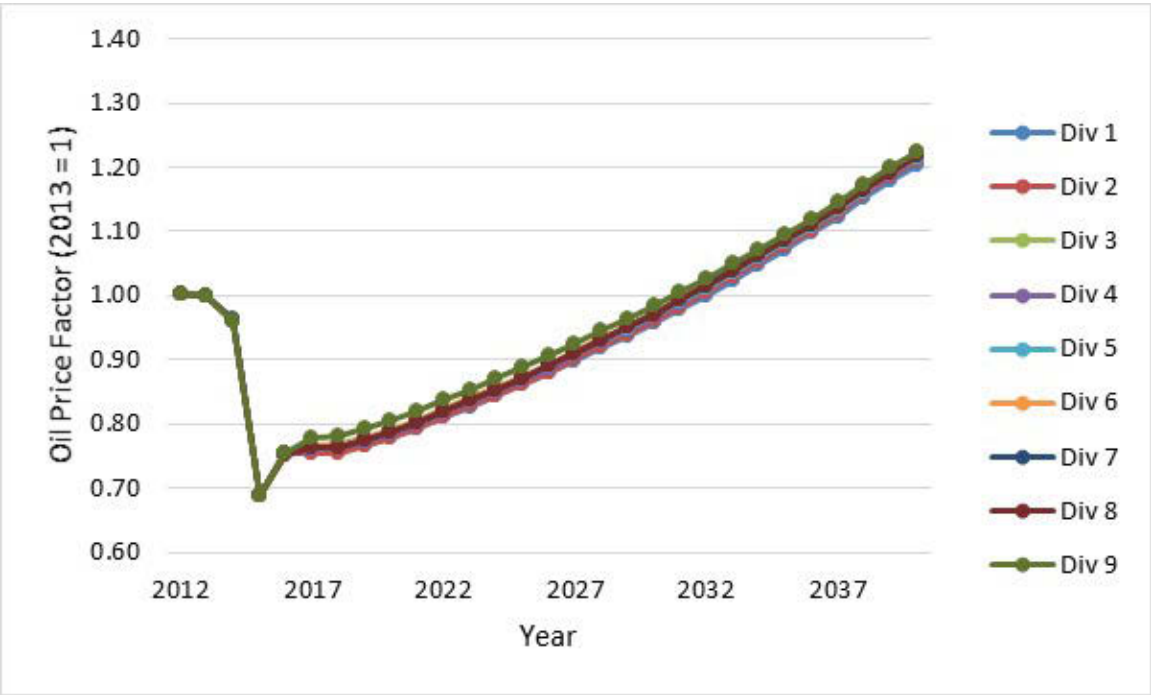

Figure 8D.6.16 Projected Commercial Fuel Oil Price Factors by Census Division

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APPENDIX 8E. MAINTENANCE AND REPAIR COST DETERMINATION FOR RESIDENTIAL BOILERS

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APPENDIX 8E. MAINTENANCE AND REPAIR COST DETERMINATION FOR RESIDENTIAL BOILERS

8E.1 INTRODUCTION

This appendix provides further details about the derivation of maintenance and repair costs for residential boilers.

The Department of Energy (DOE) estimated maintenance and repair costs for boilers based on RS Means, a well-known and respected construction cost estimation method, as well as manufacturer literature and information from expert consultants. Table 8E.1.1 offers an example of the cost calculation method. All labor costs are derived using the latest residential repair and remodeling 2015 RS Means labor costs by crew type.[1] Maintenance and repair cost tables include a trip charge, which is often charged by contractors and calculated to be equal to one half hour of labor per crew member. Labor hours (or person-hours) are based on RS Means data, expert data, or engineering judgment. Bare costs are all the costs without any markups. Material costs are based on RS Means data, expert data, or internet sources. The total includes overhead and profit (O&P), which is calculated using labor and material markups from RS Means. Values reported in this appendix are based on national average labor costs. The labor costs shown in the tables in this appendix are the national average values. In its analysis, DOE used regional material and labor costs to more accurately estimate maintenance and repair costs by region. Section 8E.4 describes the derivation of regional material and labor costs. DOE then applied the appropriate regional material and labor cost to each RECS sample household. The total costs include O&P.

Table 8E.1.1 Example Cost Table

Description	Crew	Labor Hours	Unit	Bare Costs *(2013$)*			Quantity	Total incl. O&P
				Material	Labor	Total		
Trip Charge	CREW1	0.5	-	0.00	23.00	23.00	1	35.00
Description of Cost Item	CREW1	0.5	Ea.	15.00	23.00	48.00	1	51.50
Total		1.0		15.00	46.00	71.00		**86.50**

8E.2 MAINTENANCE COST FOR RESIDENTIAL BOILERS

The maintenance cost is the routine annual cost to the consumer of general maintenance for equipment operation. DOE estimated maintenance costs at each considered efficiency level using a variety of sources, including *2015 RS Means Facilities Repair and Maintenance Data*,[2] manufacturer literature, and information from expert consultants. For AFUE standards analysis, DOE assumed that the maintenance cost is higher for condensing boilers. DOE added additional maintenance requirements for condensing boilers, including inspection of condensate system, replacement of condensate neutralizer filter, and increased maintenance for oil-fired boilers in high sulfur oil heating fuel areas. For standby and off mode standards, DOE assumed no additional maintenance costs for the baseline or higher-efficiency design options. DOE accounted for regional differences in material and labor costs, as is discussed in section 8E.4.

The frequency with which the maintenance occurs was derived from RECS 2009 and CBECS 2003 data about how often boiler owners perform maintenance and the 2008 American Home Comfort Survey (AHCS)[3] on the last time homeowners performed maintenance on their heating, ventilation, and air conditioning (HVAC) systems. RECS 2009 and CBECS 2003 survey respondents identified whether or not they performed regular maintenance. The 2008 consumer survey[3] reported the last time owners of different types of HVAC systems last performed maintenance. DOE assumed that regularly maintained boilers reported in RECS 2009 or CBECS 2003 are maintained 81 percent of the time every year and 19 percent of the time every two years, while boilers that are not regularly maintained are maintained 58 percent of the time every five years and 42 percent of the time every 20 years (see Table 8E.2.1).

Table 8E.2.1 Maintenance Frequency Based on RECS 2009, CBECS 2003, and 2008 American Home Comfort Survey

2008 AHCS Data		RECS 2009/CBECS 2003 Data	DOE Analysis Assumptions	
Date of Last Boiler Maintenance	**Fraction of Households**	**Reported Regular Maintenance**	**Assumed Frequency**	**Fraction of Households**
Within a year	71%	Yes	Annual	81%
Within two years	17%		Every Two Years	19%
Over 2 years	7%	No	Every 5 years	58%
Never	5%		Every 20 Years	42%

DOE assumed that the labor hours required to perform boiler maintenance tasks would be 1.495 hours as reported in RS Means in addition to a 0.5 hours for the trip charge.[4] For condensing boilers, DOE assumed an additional 0.077 labor hours to check the condensate withdrawal system. DOE also assumed that the condensate neutralizer is cleaned every 3 years if present, which requires an additional 0.078 hours for each cleaning.

For condensing oil boilers, the high quantity of sulfur in the fuel oil results in frequent cleaning of the secondary heat exchanger, which DOE included in its analysis. DOE investigated the effects of recent low sulfur fuel oil requirements on oil boiler maintenance (see section 8E.2.1). Based on the information presented in section 8E.2.1, DOE adjusted maintenance costs to account or these changes. Around 61 percent of residential boiler shipments are to states that currently have or will have low sulfur restrictions. Some studies suggest that low sulfur fuel oil can reduce maintenance costs. For this analysis, DOE made the following assumptions:

1) Non-regulated areas: Purchase high sulfur oil fuel with the current maintenance frequency for non-condensing and condensing products. For this analysis, the frequency

of maintenance remains the same, but condensing maintenance costs include an additional 0.254 hour of labor.

2) Regulated areas: Purchase low sulfur oil with decreased maintenance costs for all products. For this analysis, the frequency of maintenance is halved.

3) Fuel prices were assumed to be already adjusted in *AEO 2015* projections.

8E.2.1 Low Sulfur Fuel Oil

8-E.2.1.1 Sulfur Production

Ordinary oil fuel used for heating in the United States typically contains sulfur levels on the order of 2,500 parts per million.[5] Approximately 99 percent of the burned sulfur turns into sulfur dioxide (SO_2), which, when emitted into the atmosphere, can irritate lungs, contribute to pulmonary disease, and create haze.[6]

In addition to the production of SO_2, a small amount of the sulfur present in fuel oil is also converted during combustion into sulfur trioxide (SO_3). SO_3 combines with the water present in combustion gas and creates sulfuric acid, which condenses within heat exchangers and venting systems when heated to high temperatures. This sticky acid can react with the iron or steel of the heat exchanger walls, flue pipe, and chimney interior to create scale, which both reduces the boiler's efficiency and damages the equipment.[5]

Low sulfur fuel oil has a smaller amount of sulfur present, typically on the order of 15 to 500 ppm. Not only can the use of low sulfur fuel oil reduce production of sulfur dioxide and trioxide, but the same process that removes sulfur from fuel has the added benefit of also removing nitrogen.[7] 11/18/2015 4:08:00 PM

8-E.2.1.2 Current Regulatory Requirements

New York was the first state to mandate the EPA rules that established the use of Ultra Low Sulfur Diesel (ULSD) (less than 15 ppm sulfur) for transportation in certain parts of the country[8] be applied to heating oil. The following chart shows the individual states that have also mandated ULSD levels for heating oil.[9]

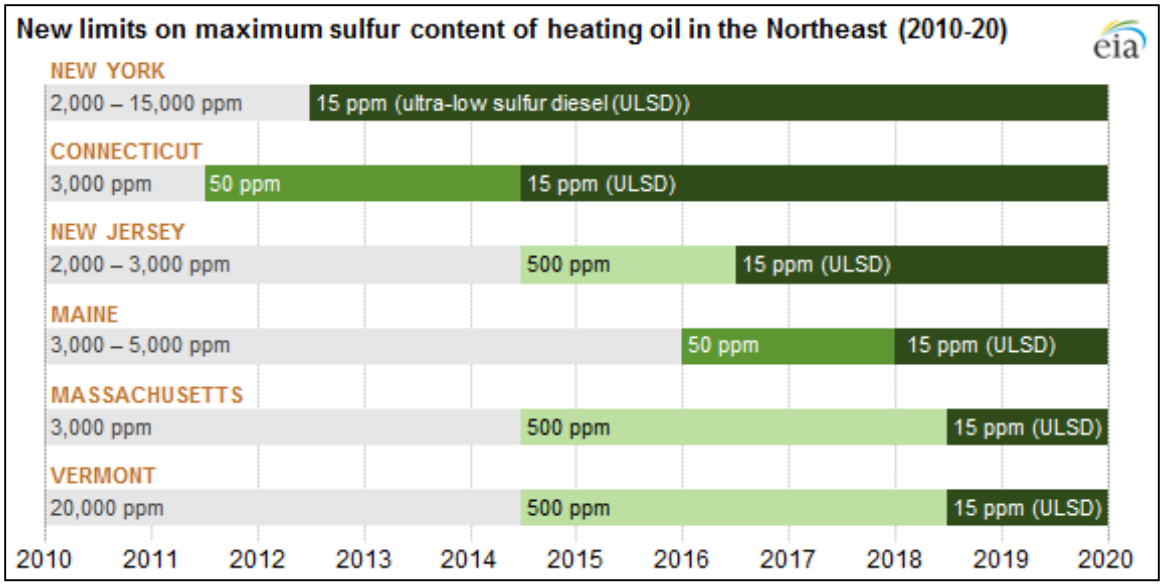

Figure 8E.2.1 States with Low Sulfur Regulations

Several sources state that the Northeast restrictions that will take effect in 2018 will mark a drastic decline of the high sulfur fuel market in the U.S.[10,11,12]

At the federal level, high sulfur diesel exists despite being banned for on-road use in 2010 and off-road use (such as barges and locomotives) in 2012.[10] However, lowering the sulfur content of highway diesel has had some impact on heating oil sulfur content as well. Because refineries are manufacturing highway diesel and heating fuel through the same process, there is often a mix of the two fuels, leading to lower sulfur levels in heating fuel. Therefore, heating fuel refined directly after highway diesel has decreased overall sulfur content.[13]

8-E.2.1.3 Reduction of Sulfur Effects on Boiler Maintenance

A variety of sources cite the fact that lower-sulfur fuel can reduce operating and maintenance costs and improve boiler efficiency. [6,14,15] Tests by Brookhaven National Laboratory and the New York State Energy Research and Development Authority (NYSERDA) show that 500 ppm low sulfur fuel leads to very clean heat exchangers, while 15 ppm fuel leads to completely clean heat exchangers.[6,16] The most consistent decrease in the rate of sulfur particles collecting on solid surfaces was two-and-a-half times, but some test results have shown even better rates.[13] NYSERDA and Brookhaven studied 20 homes in a larger 1,000 home study to assess fouling deposits. The following graph shows some of their findings:

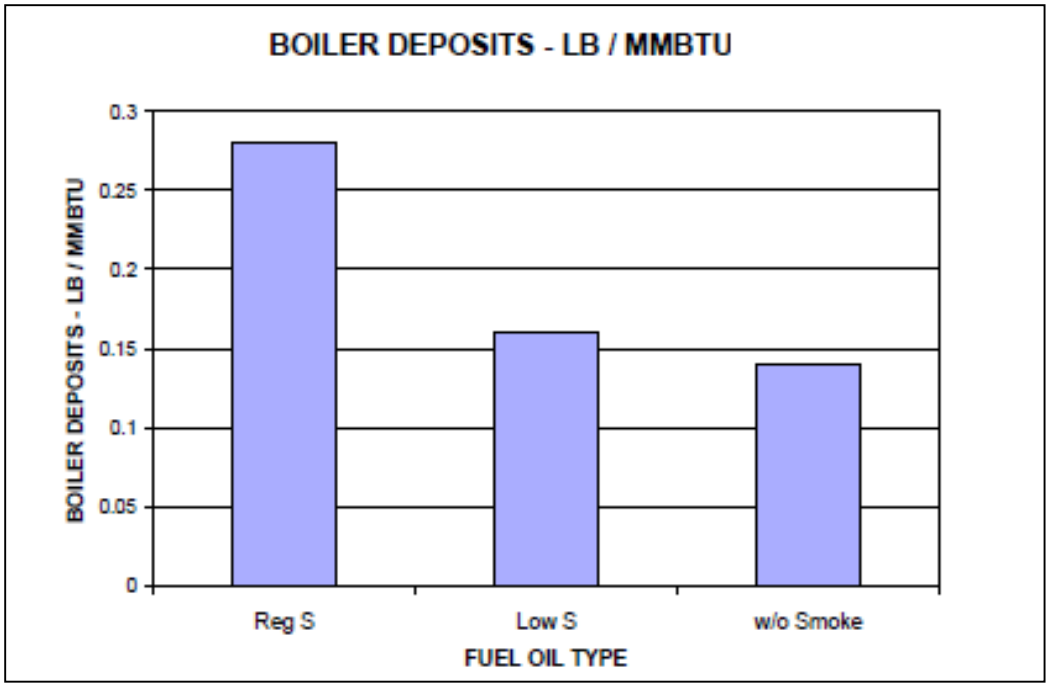

Figure 8E.2.2 Boiler Deposits by Fuel Oil Type

Normal sulfur oil produced 0.28 pounds of deposits per million BTU of fuel consumed. Deposits in the low sulfur group, excluding "heating only boilers" and "high smoke boilers," produced 0.14 pounds per million BTU of fuel. This equates to a 2:1 reduction in deposits from the use of low sulfur fuel oil, results which agree with research conducted by Brookhaven National Laboratory and CAMET Energy Technology Centre in Canada.[16] A 1995 report entitled "Oilheat Advantages Project – Engineering Analysis and Documentation Report" also states that decreased fouling of heat exchangers from low sulfur fuel can either extend the period between cleanings from 21 months (the average interval between cleanings) to 58 months, or cleanings at the existing frequency will take less time than the current average of 1.1 hours.[13]

Using lower-sulfur heating oil with boiler systems can not only reduce the emission of particulate matter, but also allow the use of secondary condensing heat exchangers on oil-fired boilers.[17]

There are some drawbacks to using low sulfur fuel. In 2003, the German organization *Institut Fur wirtschafliche Oelheizung* tested 50 ppm fuel with condensing and wall hung units with blue flame burners (which burn at a higher temperature than standard current yellow flame oil-fired burners), and found that the combustion was impacted by low lubricity and metal dusting. However, these issues may also be related to the blue flame burners, as the metal dusting was not observed in the field.[6] More information is needed to determine the application of higher temperature blue flame burners in the U.S. market.

Boilers that burn either residual or heavy-distillate fuel oils require more maintenance because of soot-production. To compensate for this production, daily soot blowing is required

during the heating season to remove excess soot from heat exchanger surfaces, in addition to regular boiler tuning to ensure proper combustion air volume.[17]

MJ Bradley and Associates recommend the following annual maintenance service for boilers that burn No. 2, distillate, heating oil:[17]

- Burner tip and heat exchanger cleaning
- Ash and soot removal
- Flue gas analysis/carbon monoxide test
- Air intake filter replacement
- Oil filter replacement

For residential boilers that burn natural gas, less maintenance is required but should still include:

- Air intake filter replacement
- Flue gas analysis/carbon monoxide test

8-E.2.1.4 Market Share of Low Sulfur Residential Boilers

Based on the list of states in Table 8E.2.2 with low sulfur restrictions and the number of residential oil-fired boiler shipments from 2008-2012 to those states,[18] DOE approximated that 24 percent of residential boilers shipments are currently to areas with low sulfur restrictions and estimated that this fraction could rise to 95 percent by 2021.

Table 8E.2.2 States and Year of SO_X Regulation Implementation, and Regional Oil-fired Boiler Market Shares

State	Year of Implementation	Residential Oil-fired Boiler Shipment Fraction from AHRI Data (2008-2012)
New York	2012 (<15 ppm)	24.3%
Connecticut	2014 (<500 ppm), 2018 (<15 ppm)	11.4%
Delaware	2016 (<15 ppm)	0.3%
District of Columbia	2016 (<500 ppm), 2018 (<15 ppm)	0.04%
Maine	2018 (<15 ppm)	3.5%
Maryland	2014 (<2000 ppm), 2016 (<500 ppm)	7.4%
Massachusetts	2014 (<500 ppm), 2018 (<15 ppm)	15.9%
New Hampshire	Current (<4000 ppm)	14.0%
New Jersey	2014 (<500 ppm)	5.6%
Pennsylvania	2016 (<500 ppm)	10.6%
Rhode Island	2014 (<500 ppm)	1.3%
Vermont	2014 (<50 ppm), 2018 (ULSD, <15ppm)	0.4%
	Total by 2021	94.7%

Source: Energy Information Administration.[9, 12], Energy Kinetics, No. 52 at pp. 2-3[a]

8-E.2.1.5 Low Sulfur Energy Prices

Heating oil prices are influenced by factors such as demand per season, the cost of crude oil, competition among heating oil dealers, and regional costs such as distribution. Marketing and distribution usually accounts for 46 percent of the retail price to consumers.[13] Low sulfur regulations could also potentially affect the price of fuel oil. A 2003 report cites the price differential between regular #2 heating oil and low sulfur oil as one to two cents per gallon.[13] Research funded by the Connecticut government states that the stock of ultra-low sulfur fuel in the US has increased significantly over the last decade, which would also affect pricing.[6] Data already shows that New York State's requirement of ultra-low sulfur fuel oil will result in slightly higher heating oil futures prices when compared to historical prices. For example, in February and March of 2013, the difference between the April heating oil contract and the May heating oil contract averaged nearly $0.08 per gallon."[9]

DOE believes that low sulfur oil pricing for regulated regions is already taken into account in EIA's *AEO 2015* projections, and therefore did not make any adjustments to the energy price data to account for low-sulfur oil prices.

[a] A notation in this form provides a reference for information that is in the docket of DOE's rulemaking to develop energy conservation standards for residential boilers (Docket No. EERE-2012-BT-STD-0047), which is maintained at www.regulations.gov. This notation indicates that the statement preceding the reference is document number 52 in the docket for the residential boilers energy conservation standards rulemaking, and appears at pages 2-3 of that document.

8E.2.2 Maintenance Cost Results for Residential Boilers

Table 8E.2.3 show the total maintenance cost, and associated incremental cost compared to the baseline, as well as the maintenance year applied in the LCC analysis for residential boilers.

Table 8E.2.3 Average Maintenance Cost and Average Maintenance Year for Residential Boilers (2014$)

Product Class	Efficiency Level	Maintenance Cost 2014$	Incremental Cost 2014$	Maintenance Year
Gas-Fired Hot Water Boiler	82% AFUE - Baseline	$201	-	7.4
	83% AFUE - Increased HX Area	$201	$0.00	7.4
	84% AFUE - Increased HX Area	$201	$0.00	7.4
	85% AFUE - Increased HX Area	$201	$0.00	7.4
	90% AFUE - Condensing Baseline	$209	$8.05	7.4
	92% AFUE - Increased HX Area	$209	$8.05	7.4
	96% AFUE - Max Tech	$209	$8.05	7.4
Gas-Fired Steam Boiler	80% AFUE - Baseline	$201	-	7.5
	82% AFUE - Increased HX Area	$201	$0.00	7.5
	83% AFUE - Max Tech	$201	$0.00	7.5
Oil-Fired Hot Water Boiler	84% AFUE - Baseline	$200	-	4.0
	85% AFUE - Increased HX Area	$200	$0.00	4.0
	86% AFUE - Increased HX Area	$200	$0.00	4.0
	91% AFUE - Condensing (Max Tech)	$208	$8.48	4.0
Oil-Fired Steam Boiler	82% AFUE - Baseline	$203	-	4.3
	84% AFUE - Increased HX Area	$203	$0.00	4.3
	85% AFUE - Increased HX Area	$203	$0.00	4.3
	86% AFUE - Max Tech	$203	$0.00	4.3

8E.3 REPAIR COST FOR RESIDENTIAL BOILERS

The repair cost is the cost to the consumer for replacing or repairing components in the residential boiler that have failed. DOE estimated repair costs at each considered efficiency level using a variety of sources, including Burnham Holding's contractor data (Burnham, No. 60 at pp. 32-33), *2015 RS Means Facility Repair and Maintenance Data*,[4] manufacturer literature, and information from expert consultants. DOE estimated repair rates by using information from manufacturer literature, expert consultants, and stakeholder comment to determine Weibull distributions representing the lifetime of each component. DOE accounted for regional differences in material and labor costs, as is discussed in section 8E.4. Table 8.1.5 and Table 8.1.6 show repair rate and cost assumptions that DOE used in its analysis.

Table 8E.3.1 Boiler Repair Rates

Repair Description	Mean Failure Year	Repair Rate
Ignition, Controls, Gas Valve, Automatic Means	12.0	50%
Mechanical Vent or Power Vent Blower	15.0	25%
Heat Exchanger (Non-Condensing)	27	1%
Heat Exchanger (Condensing)	20	2%

Table 8E.3.2 Boiler Repair Costs

Repair Description	Bare Material Cost (2014$)*	Total Labor Hours**
Ignition, Controls, Gas Valve, Automatic Means (for Non-Condensing Boiler)	$135.81	1.70
Ignition, Controls, Gas Valve, Automatic Means (for Condensing Boilers)	$281.57	2.20
Blower (for Non-Condensing Boiler)	$245.79	3.43
Blower (for Condensing Boiler)	$316.34	3.93
Heat Exchanger (for Non-Condensing Boiler)	Half of Eqp Price	10.50
Heat Exchanger (for Condensing Boiler)	Half of Eqp Price	10.50

*Does not include sales tax or markups.
**Includes 0.5 hour trip charge for each task.

Table 8.1.7 through Table 8.1.9 show the fractions residential boilers that undergo repairs, the total repair cost, and associated incremental cost compared to the baseline, as well as the repair year for all components considered in the repair methodology for residential boilers.

Table 8E.3.3 Repair Costs Applied for Ignition, Controls, Gas Valves, or Automatic Means for Residential Boilers (2014$)

Product Class	Efficiency Level	Fraction with Repair	Total Repair Cost *2014$*	Incremental Cost *2014$*	Repair Year
Gas-Fired Hot Water Boiler	82% AFUE - Baseline	43%	$326.9	-	11.9
	83% AFUE - Increased HX Area	43%	$326.9	$0.00	11.9
	84% AFUE - Increased HX Area	43%	$326.9	$0.00	11.9
	85% AFUE - Increased HX Area	43%	$326.9	$0.00	11.9
	90% AFUE - Condensing Baseline	43%	$546.2	$219.27	11.9
	92% AFUE - Increased HX Area	43%	$546.2	$219.27	11.9
	96% AFUE - Max Tech	43%	$546.2	$219.27	11.9
Gas-Fired Steam Boiler	80% AFUE - Baseline	42%	$329.5	-	11.8
	82% AFUE - Increased HX Area	42%	$329.5	$0.00	11.8
	83% AFUE - Max Tech	42%	$329.5	$0.00	11.8
Oil-Fired Hot Water Boiler	84% AFUE - Baseline	43%	$327.2	-	11.9
	85% AFUE - Increased HX Area	43%	$327.2	$0.00	11.9
	86% AFUE - Increased HX Area	43%	$327.2	$0.00	11.9
	91% AFUE - Condensing (Max Tech)	43%	$546.8	$219.54	11.9
Oil-Fired Steam Boiler	82% AFUE - Baseline	37%	$329.8	-	11.6
	84% AFUE - Increased HX Area	37%	$329.8	$0.00	11.6
	85% AFUE - Increased HX Area	37%	$329.8	$0.00	11.6
	86% AFUE - Max Tech	37%	$329.8	$0.00	11.6

Table 8E.3.4 Repair Costs Applied for Mechanical Vent or Power Blowers for Residential Boilers (2014$)

Product Class	Efficiency Level	Fraction with Repair	Total Repair Cost *2014$*	Incremental Cost *2014$*	Repair Year
Gas-Fired Hot Water Boiler	82% AFUE - Baseline	1.2%	$630	-	14.2
	83% AFUE - Increased HX Area	1.2%	$630	$0	14.2
	84% AFUE - Increased HX Area	1.2%	$630	$0	14.2
	85% AFUE - Increased HX Area	9.2%	$627	($2)	14.3
	90% AFUE - Condensing Baseline	19%	$759	$130	14.2
	92% AFUE - Increased HX Area	19%	$759	$130	14.2
	96% AFUE - Max Tech	19%	$759	$130	14.2
Gas-Fired Steam Boiler	80% AFUE - Baseline	0.0%	$0	-	---
	82% AFUE - Increased HX Area	0.9%	$627	$627	13.5
	83% AFUE - Max Tech	1.8%	$633	$633	13.4
Oil-Fired Hot Water Boiler	84% AFUE - Baseline	0.0%	$0	-	---
	85% AFUE - Increased HX Area	0.0%	$0	$0	---
	86% AFUE - Increased HX Area	0.0%	$0	$0	---
	91% AFUE - Condensing (Max Tech)	19%	$763	$763	14.1
Oil-Fired Steam Boiler	82% AFUE - Baseline	0.0%	$0	-	---
	84% AFUE - Increased HX Area	0.0%	$0	$0	---
	85% AFUE - Increased HX Area	0.0%	$0	$0	---
	86% AFUE - Max Tech	0.0%	$0	$0	---

Table 8E.3.5 Repair Costs Applied to Heat Exchangers for Residential Boilers (2014$)

Product Class	Efficiency Level	Fraction with Repair	Total Repair Cost *2014$*	Incremental Cost *2014$*	Repair Year
Gas-Fired Hot Water Boiler	82% AFUE - Baseline	0.2%	$2,275	-	25.6
	83% AFUE - Increased HX Area	0.2%	$2,284	$9	25.6
	84% AFUE - Increased HX Area	0.2%	$2,293	$17	25.6
	85% AFUE - Increased HX Area	0.2%	$2,364	$89	25.6
	90% AFUE - Condensing Baseline	6.2%	$2,715	$440	21.6
	92% AFUE - Increased HX Area	6.2%	$2,919	$644	21.6
	96% AFUE - Max Tech	6.2%	$3,321	$1,046	21.6
Gas-Fired Steam Boiler	80% AFUE - Baseline	0.2%	$2,572	-	25.8
	82% AFUE - Increased HX Area	0.2%	$2,591	$18	25.8
	83% AFUE - Max Tech	0.2%	$2,749	$177	25.8
Oil-Fired Hot Water Boiler	84% AFUE - Baseline	0.2%	$3,400	-	25.3
	85% AFUE - Increased HX Area	0.2%	$3,488	$88	25.3
	86% AFUE - Increased HX Area	0.2%	$3,576	$176	25.3
	91% AFUE - Condensing (Max Tech)	5.5%	$4,641	$1,241	21.5
Oil-Fired Steam Boiler	82% AFUE - Baseline	0.1%	$3,574	-	25.3
	84% AFUE - Increased HX Area	0.1%	$3,755	$181	25.3
	85% AFUE - Increased HX Area	0.1%	$3,845	$271	25.3
	86% AFUE - Max Tech	0.1%	$4,025	$452	25.3

8E.4 SENSITIVITY ANALYSIS

DOE conducted a sensitivity analysis for its repair cost estimates to assess the impact of varying repair frequency on consumer LCC savings. DOE derived alternative low and high repair scenarios based on doubling the repair frequency for high repair scenario and decreasing the repair frequency by half for the low repair scenario compared to the reference repair frequency and applied it to the LCC and PBP analysis. Table 8E.4.1 lists the repair frequency for high repair, low repair, and reference scenarios by product class. The results of the repair sensitivity analysis are shown in Table 8E.4.2 for the low and high repair scenarios. The sensitivity analysis results demonstrate that the LCC savings and payback period for non-condensing efficiency levels are less sensitive to the repair frequency compared to condensing efficiency levels. Note that the simple impact results are not impacted by the scenarios since simple payback calculation does not include repair costs.

Table 8E.4.1 Comparison of Repair Frequency for Reference, Low, and High Repair Scenarios

Product Class	EL	Ignition, Controls, Gas Valve, Other *Repair Frequency, %*			Inducer Blower *Repair Frequency, %*			Mechanical Exchanger *Repair Frequency, %*		
		Ref	**Low**	**High**	**Ref**	**Low**	**High**	**Ref**	**Low**	**High**
Gas-fired Hot Water Boiler	0	43%	22%	87%	1.2%	0.5%	2.3%	0.2%	0.1%	0.5%
	1	43%	22%	87%	1.2%	0.5%	2.3%	0.2%	0.1%	0.5%
	2	43%	22%	87%	1.2%	0.5%	2.3%	0.2%	0.1%	0.5%
	3	43%	22%	87%	9.2%	4.3%	19%	0.2%	0.1%	0.5%
	4	43%	22%	87%	19%	9.4%	40%	6.2%	3.0%	12%
	5	43%	22%	87%	19%	9.4%	40%	6.2%	3.0%	12%
	6	43%	22%	87%	19%	9.4%	40%	6.2%	3.0%	12%
Gas-fired Steam Boiler	0	42%	21%	83%	0.0%	0.0%	0.0%	0.2%	0.1%	0.4%
	1	42%	21%	83%	0.9%	0.4%	1.7%	0.2%	0.1%	0.4%
	2	42%	21%	83%	1.8%	0.9%	3.7%	0.2%	0.1%	0.4%
Oil-fired Hot Water Boiler	0	43%	22%	85%	0.0%	0.0%	0.0%	0.2%	0.1%	0.4%
	1	43%	22%	85%	0.0%	0.0%	0.0%	0.2%	0.1%	0.4%
	2	43%	22%	85%	0.0%	0.0%	0.0%	0.2%	0.1%	0.4%
	3	43%	22%	85%	19%	9.3%	39%	5.5%	2.7%	11%
Oil-fired Steam Boiler	0	37%	19%	74%	0.0%	0.0%	0.0%	0.1%	0.0%	0.2%
	1	37%	19%	74%	0.0%	0.0%	0.0%	0.1%	0.0%	0.2%
	2	37%	19%	74%	0.0%	0.0%	0.0%	0.1%	0.0%	0.2%
	3	37%	19%	74%	0.0%	0.0%	0.0%	0.1%	0.0%	0.2%

Table 8E.4.2 Comparison Average LCC Savings, Percent of Consumers that Experience Net Cost, and Simple Payback Period Results for Reference, Low, and High Repair Scenarios

Product Class	EL	Average LCC Savings *2014$*			% of Consumers that Experience Net Cost *%*			Simple Payback Period *Years*		
		Ref	Low	High	Ref	Low	High	Ref	Low	High
Gas-fired Hot Water Boiler	1	$210	$210	$210	0.3%	0.3%	0.3%	1.2	1.2	1.2
	2	$364	$364	$364	0.4%	0.4%	0.4%	1.2	1.2	1.2
	3	$182	$205	$133	13.0%	12.8%	13.5%	7.5	7.5	7.5
	4	$632	$788	$322	21.9%	20.7%	24.3%	8.4	8.4	8.4
	5	$513	$643	$256	29.2%	28.0%	31.5%	9.9	9.9	9.9
	6	$303	$386	$140	55.5%	54.1%	58.2%	11.8	11.8	11.8
Gas-fired Steam Boiler	1	$333	$336	$329	0.9%	0.9%	0.9%	2.7	2.7	2.7
	2	$207	$213	$196	30.8%	30.6%	30.6%	10.7	10.7	10.7
Oil-fired Hot Water Boiler	1	$260	$260	$260	10.4%	10.4%	10.4%	6.9	6.9	6.9
	2	$626	$626	$626	8.8%	8.8%	8.8%	5.8	5.8	5.8
	3	$192	$369	($146)	58.9%	56.9%	56.9%	16.5	16.5	16.5
Oil-fired Steam Boiler	1	$400	$400	$400	11.9%	11.9%	11.9%	6.6	6.6	6.6
	2	$434	$434	$434	19.7%	19.7%	19.7%	6.7	6.7	6.7
	3	$505	$505	$505	34.2%	34.2%	34.2%	7.8	7.8	7.8

8E.5 REGIONAL MATERIAL AND LABOR COSTS

DOE used regional material and labor costs to more accurately estimate maintenance, and repair costs by region. RS Means provides average national labor costs for different trade groups. DOE used the residential repair and remodeling labor cost from RS Means crew type Q1 (1 Plumber, 1 Plumber Apprentice) for all repair and maintenance labor cost calculations as shown in Table 8E.4.1.[1] Bare costs are given in RS Means, while labor costs including overhead and profit (O&P) are the bare costs multiplied by the RS Means markups shown in Table 8E.4.2.

Table 8E.5.1 RS Means 2015 National Average Labor Costs by Crew (2014$)

Crew Type	Crew Description	Laborers per Crew	Cost per Labor-Hour	
			Bare Costs	Incl. O&P*
2015 RS Means Labor Costs Data (Residential, Repair/Remodeling)				
Q1	1 Plumber, 1 Plumber Apprentice	2	$52.78	$82.33

* O&P includes markups

Table 8E.5.2 RS Means Labor Costs Markups by Trade

Trade	Workers Comp.	Aver Fixed Overhead	Overhead	Profit	Total
Plumber (Repair/Remodel)	7.0%	18.0%	16.0%	10.0%	5.0%

RS Means also provides material and labor cost factors for 295 cities and towns in the U.S. To derive average labor cost values by state, DOE weighted the price factors by city or town population size using 2012 census data. To weight these values by geographical region for the RECS 2009 and CBECS 2003 sample, DOE used 2008-2012 state shipment data.[18] DOE used the material and labor cost factors for cost associated with fire suppression, plumbing, and HVAC. Table 8E.4.3 and Table 8E.4.4 show the final regional material and labor price factors used in the analysis by geographical area. The distribution of each CBECS 2003 equipment class sample is different, so the average labor cost weighted by CBECS 2003 sample weights is different from the RS Means national average labor cost factor of 1.00.

Table 8E.5.3 Material and Labor Cost Factors by RECS 2009 Geographical Area

Geographical Area (Census Division)	Material	Labor
Connecticut, Maine, New Hampshire, Rhode Island, Vermont	0.99	0.90
Massachusetts	1.00	1.19
New York	1.00	1.61
New Jersey	1.00	1.25
Pennsylvania	0.98	1.14
Illinois	0.99	1.28
Indiana, Ohio	0.99	0.89
Michigan	1.00	1.01
Wisconsin	0.99	0.95
Iowa, Minnesota, North Dakota, South Dakota	0.99	0.97
Kansas, Nebraska	0.99	0.74
Missouri	0.99	0.96
Virginia	0.99	0.66
Delaware, District of Columbia, Maryland	0.98	0.84
Georgia	0.99	0.66
North Carolina, South Carolina	1.00	0.36
Florida	1.00	0.69
Alabama, Kentucky, Mississippi	0.99	0.75
Tennessee	1.00	0.71
Arkansas, Louisiana, Oklahoma	1.00	0.59
Texas	0.99	0.56
Colorado	0.99	0.79
Idaho, Montana, Utah, Wyoming	1.00	0.70
Arizona	1.00	0.80
Nevada, New Mexico	1.00	0.76
California	0.99	1.21
Oregon, Washington	1.00	1.04
Alaska	1.00	1.05
Hawaii	1.00	1.10
West Virginia	0.98	0.85

Table 8E.5.4 Material and Labor Cost Factors by CBECS 2003 Geographical Area

Geographical Area (Census Division)	Material	Labor
New England	0.99	1.02
Middle Atlantic	0.99	1.43
East North Central	0.99	1.06
West North Central	0.99	0.96
South Atlantic	0.98	0.79
East South Central	1.00	0.73
West South Central	1.00	0.58
Mountain	1.00	0.76
Pacific	1.00	1.07

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APPENDIX 8F. RESIDENTIAL BOILER LIFETIME DETERMINATION

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APPENDIX 8F. RESIDENTIAL BOILER LIFETIME DETERMINATION

8F.1 INTRODUCTION

DOE defines lifetime as the age when a product is retired from service. DOE notes that a large percentage of residential boilers designs now on the market were not available 10+ years ago; therefore, comprehensive lifetime data is not yet available. Also, there is an ongoing evolution of the boiler component lifetime, which has not been thoroughly assessed yet.[1]

DOE used national survey data, along with manufacturer shipment data, to calculate the distribution of residential boiler lifetimes based on methods from Lutz *et al*. (2011).[2] DOE used the results from a contractor survey done by AHRI to adjust the lifetime of residential boilers by product class.[3] DOE estimated that the average lifetimes are 26.5 years for hot water gas-fired boilers, 23.6 years for steam gas-fired boilers, 24.7 years for hot water oil-fired boilers, and 19.2 years for steam gas-fired boilers. For electric boilers, DOE assumed the same lifetime as gas-fired boilers. DOE assumed that the lifetime of a residential boiler is the same among different efficiency levels.

8F.2 LIFETIME LITERATURE REVIEW

To compare DOE's lifetime estimates to other estimates, DOE performed a lifetime literature review. Table 8F.2.1 presents a range of product lifetimes and sources found by DOE. The data show that DOE's assumed lifetime for boilers fits within the bounds of the current boiler lifetime estimates.

Table 8F.2.1 Residential Boilers: Product Lifetime Estimates and Sources

Typical Lifetime or Range (years)	Source
Unspecified Boiler Fuel Type	
10-20	Federal Trade Commission[4]
10-15	PM Engineer (2012) [∞,5]
15	WAPTAC[6]
15-20	Dunlop (2003)[‡,†,7]
23 (historic); 17 (future)	Keman, et al.[8]
18-32	1998 Gas Research Institute[a,9]
20	1994 Gas Research Institute[b,1], PM Engineer (2002)[†,10]

[a] GRI notes that the expected (based on historic expectations on traditional equipment) lifetime of boilers was 30-50 years however they believed (based on contemporary equipment as indicated by interview and focus group responses) boiler lifetime would be 20-40 years. Actual lifetime range is listed in table and is based on actual data collected.

[b] Lifetime value represents weighted median age for servicing of a non-condensing boiler primary heat exchanger. The GRI sample includes 84 units which had a mean service lifetime of 18.9 years, weighted mean of 18.9 years, and median of 20 years.

Typical Lifetime or Range (years)	Source
21	PM Engineer (2002)[‡,10]
25-35	AHR The NEWS (1999)[11]
29	PM Engineer (2002)*[,^,10]
30	Old House Web[12]
30-50	Dunlop (2003)* [,7]
80 (coal to oil to gas)	Dunlop (2003)*[,7]
20-30	EIA (2013)
Gas Boilers	
Low = 13, Ave=17, High=22	1990 Gas Research Institute (GRI) study[13]
15-20	4ecotips[14]
18	Mid-Atlantic Technical Reference Manual (2011)[15]
Average = 20; Low = 17; High = 24	Appliance Magazine (2009)[16]
20	PM Engineering (2001)[†,17] , Mid-Atlantic Technical Reference Manual (2011)[15]
20-30	RAND Engineering[‡,18]
21	2007 National Association of Home Builders Study[19], PM Engineering (2001)[‡,17]
>22	ASHRAE (2011)[‡,20]
Average = 23	Keman, et al.*[8]
24-25	ASHRAE (2011)[‡,20]
24-30	American School & University[‡,21]
25	DOE 2003[22], RAND Engineering*[,18] , DCA (2011)[23]
Average = 25; Low = 20; High = 30	Residential Boilers Final Rule 2007[c,24]
25.3	LBNL study(2011)[2]
29	PM Engineering(2001)*[,^,17]
30	RS Means (2013)[25]
35	ASHRAE (2011)*[,20]
40	1994 Gas Research Institute[∞,d,1]
Oil Boilers	
Low = 12, Ave=15, High=19	1990 Gas Research Institute (GRI) study[13]
20	Nelson and Small Energy Solutions[∞26]
22	DCA (2011)[23]
Average =25; Low = 20; High = 30	Residential Boilers Final Rule 2007[e,24]

[c] Triangular distribution was used.
[d] Lifetime value represents median age for servicing of a condensing boilers primary heat exchanger. GRI notes that five units which had a mean service lifetime of 19.9 years, weighted mean of 36 years, and median of 20 years.
[e] Triangular distribution was used.

Typical Lifetime or Range (years)	Source
30	DCA (2011)[23], RS Means (2013)[25]
134 (coal to oil)	AHR The NEWS (2005)[27]
Electric Boilers	
13	2007 National Association of Home Builders Study[19]
15	ASHRAE (2011)[20]
18	GDS Associates (2012) [∞,28]
20	GDS Associates (2012)[28], DCA (2011)[23]

* Cast iron
† Copper tube
^ Stainless steel
‡ Steel
∞ Condensing

Additionally, the Air-Conditioning, Heating, and Refrigeration Institute (AHRI) conducted a survey of boiler installation contractors in which AHRI asked contractors to estimate the typical life for different types of residential boilers.[3] AHRI submitted the results of the survey in response to the NOPR. The results of the survey are shown in Figure 8F.2.2 and Figure 8F.2.3 below.

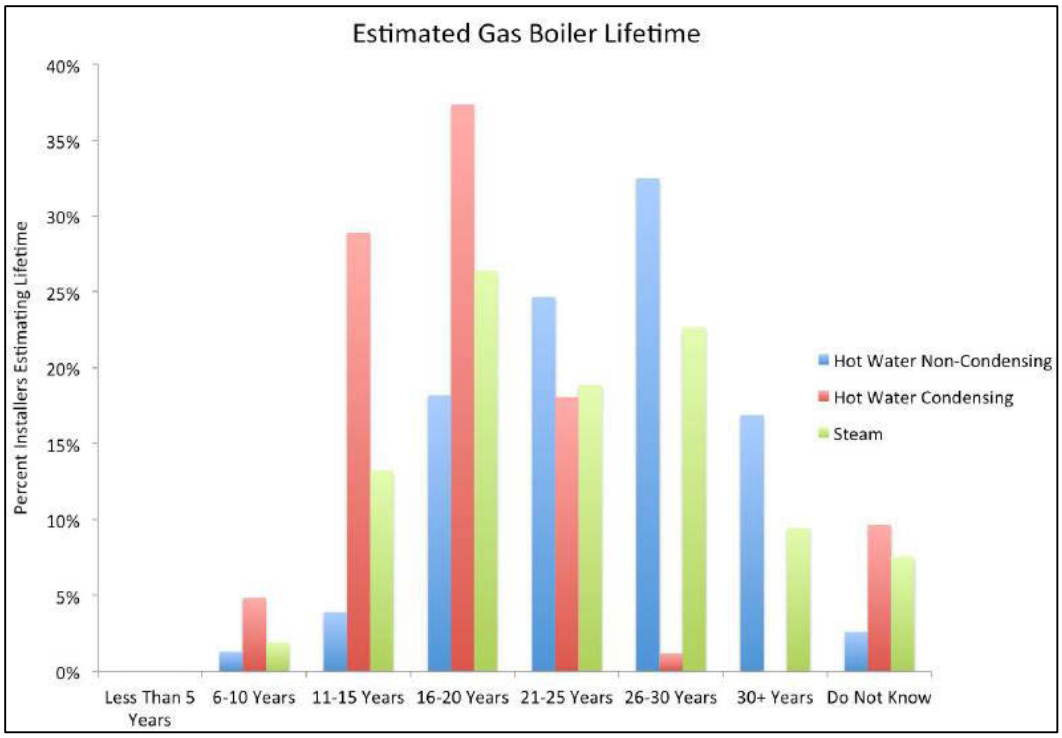

Figure 8F.2.2 AHRI Contractor Survey Results for Gas Boiler Lifetime

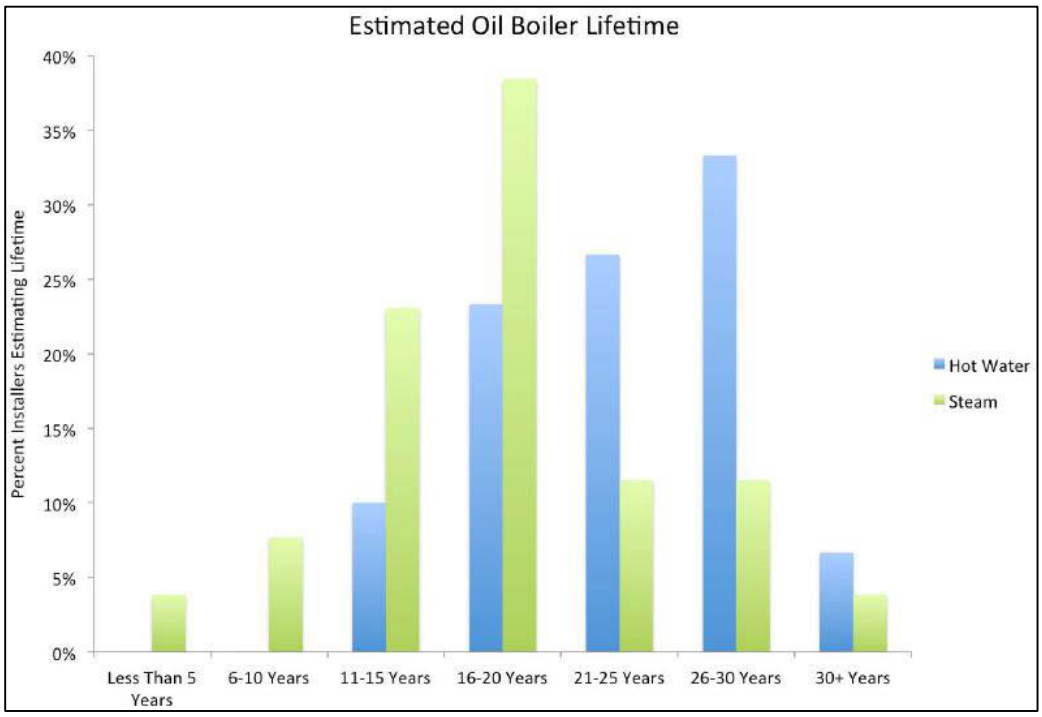

Figure 8F.2.3 AHRI Contractor Survey Results for Oil Boiler Lifetime

DOE notes that the lifetime for condensing boilers in the literature and in the AHRI contractor survey is noted as being less than that of non-condensing boilers. Additionally, stakeholders commented in response to the NOPR that condensing boilers generally have a shorter lifetime than non-condensing boilers. Burnham also stated that sources listed by DOE that pre-date 2003 (*i.e.*, around the time that the number of condensing boilers started to increase in the U.S.) cannot be used to estimate the life expectancy of condensing boilers. Burnham stated that references after 2003 should not be used either because statistically significant condensing boiler life expectancy data will take years to accumulate after these boilers were introduced into the U.S. market.[29]

Additionally, DOE conducted manufacturer interviews for the initial and NOPR analyses to gather information regarding the lifetime of residential boilers. Many manufacturers stated that the design and efficiency level of the boiler affects the expected lifetime. Several manufacturers stated that higher efficiency condensing boilers, made of stainless steel or cast aluminum, often have shorter lifetimes than lower efficiency cast iron boilers. Manufacturers pointed to the warranties offered on both types of heat exchangers to substantiate their claims. However, these manufacturers also generally noted that condensing residential boilers have only been available a relatively short time, so estimating the lifetime is difficult.

DOE has concluded that there is not enough data available to accurately distinguish the lifetime of condensing boilers because, as Burnham stated, they have not been prevalent in the

U.S. market long enough to demonstrate whether their average lifetime is less than or greater than 15 years. In addition, condensing boiler technologies have been improving since their introduction to the U.S. market; therefore, the lifetime of the earliest condensing boilers may not be representative of current or future condensing boiler designs. Therefore, condensing lifetime results from the Burnham's and AHRI's contractor survey might be biased towards earliest condensing boiler designs and lack the number of condensing boilers installed 15 years or older. Based on the lack of clear and convincing information that condensing boilers have a shorter lifetime, DOE maintained the same lifetime for condensing and non-condensing boilers. However, DOE did include additional repair costs for condensing boilers that would likely allow a similar lifetime as non-condensing boilers by assuming different service lifetimes for heat exchangers for condensing boilers and non-condensing boilers based on warranty data from product literature and survey data provided by stakeholders. DOE also conducted a sensitivity analysis using a different heat exchanger scenarios (appendix 8E) and boilers lifetime scenarios (section 8F.4).

8F.3 METHODOLOGY

DOE's lifetime methods are based on Lutz *et al*. (2011).[2] The Energy Information Administration's (EIA) Residential Energy Consumption Survey (RECS) from 1990-2009[30] surveyed occupied primary housing units, noting the presence of a range of appliances and placing the age of each appliance into several-year bins. The U.S. Census's *American Housing Survey* (AHS) from 1974-2013[31] surveyed all housing, including vacant and second homes. Using the AHS data allowed DOE to adjust the RECS data to reflect some appliance use outside of primary residences. AHS also has a larger sample size, with correspondingly smaller sampling error. By combining these survey results with DOE's estimated historical residential boiler shipments, DOE estimated the fraction of appliances of a given age still in operation. DOE's estimated historical residential boiler shipments data is described in more detail in appendix 9B.[f] This survival function, which DOE assumed has the form of a cumulative Weibull distribution, provides an estimate of the average and median appliance lifetime.

The Weibull distribution is a probability distribution function commonly used to measure failure rates.[32] Its form is similar to an exponential distribution, which would model a fixed failure rate, except that it allows for a failure rate that changes over time in a particular fashion. The cumulative distribution takes the form:

$$P(x) = e^{-\left(\frac{x-\theta}{\alpha}\right)^{\beta}} \text{ for } x > \theta \text{ and } P(x) = 1 \text{ for } x \leq \theta,$$

Eq. 8F.1

[f] DOE only used residential boiler shipments going into the residential market segment. DOE assumed that 7 percent of shipments are to commercial applications (see chapter 9).

Where:

$P(x)$ = probability that the appliance is still in use at age x,
x = appliance age,
α = the scale parameter, which is the decay length in an exponential distribution,
β = the shape parameter, which determines the way in which the failure rate changes in time, and
θ = the delay parameter, which allows for a delay before any failures occur.

When $\beta = 1$, the failure rate is constant over time, and this distribution takes the form of a cumulative exponential distribution. For the case of appliances, β is commonly greater than 1, which results from a rising failure rate as the appliance ages. A plot of a Weibull distribution (DOE's calculated boiler survival function) is shown as Figure 8F.3.1.

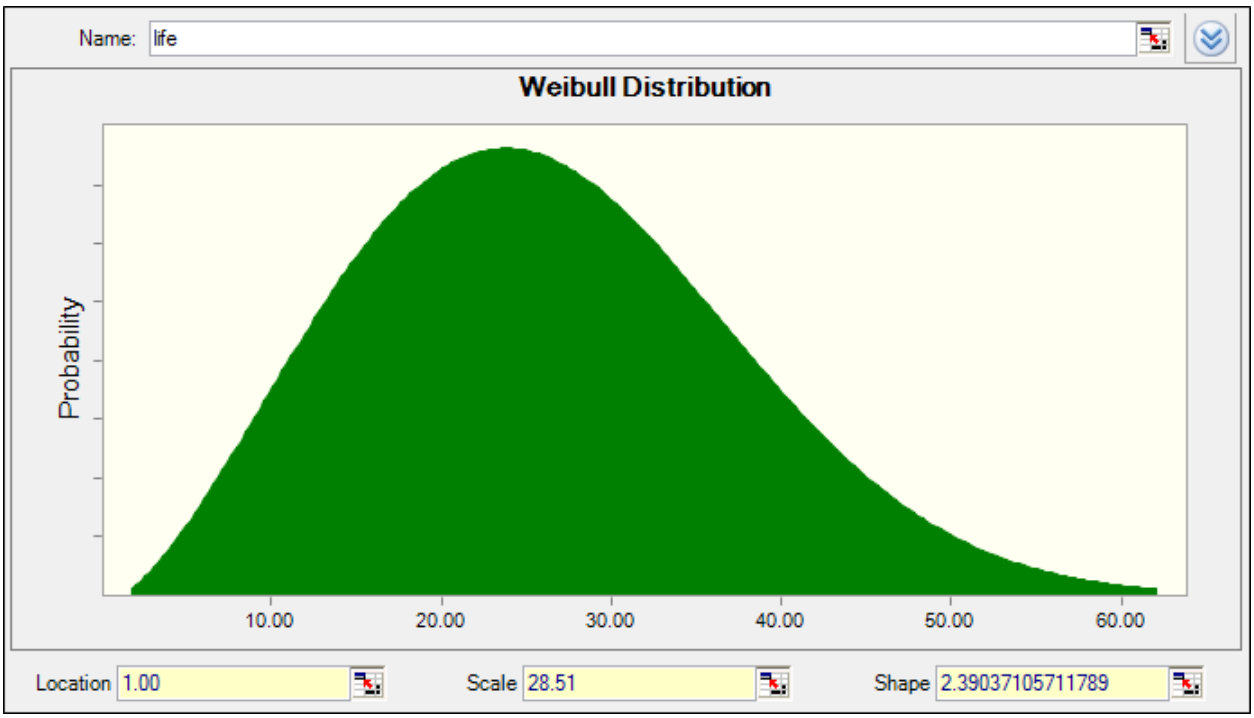

Figure 8F.3.1 Calculated Lifetime Distribution for Residential Gas-fired Boilers

The RECS survey is DOE's primary resource for boiler ages. For several appliances, including boilers, the survey asks respondents to place the appliance's age into one of these bins:[g]

- less than 2 years;

[g] For RECS 2009 the 10 to 19 year bin is split into two bins (10 to 14 years and 15 to 19 years).

- 2 to 4 years;
- 5 to 9 years;
- 10 to 19 years; and
- more than 20 years.

The RECS survey has been conducted every 3 or 4 years for the last several decades. For this analysis, DOE used the surveys conducted in 1990, 1993, 1997, 2001, 2005, and 2009.[30] DOE also used the biennial AHS surveys conducted from 1974 to 2013.[31] DOE used the AHS count of housing units with boilers to scale the RECS data to better match the total installed stock. DOE used the surveys' household-level micro-data to count households with shared or multiple boilers. Households that did not know the age of their appliances were allocated among the remaining age bins according to the distribution of respondents who did report their appliance age.

DOE used appliance age data derived from RECS, AHS total installed stock data, and historical boiler shipments to generate an estimate of the residential boiler survival function. For example, DOE summed the total shipments from 5 to 9 years prior to the RECS survey, and compared this number with the number of units of those ages still in use, to calculate one approximation of the surviving appliance fraction within that age bin. The AHS total stock acts as an "all ages" bin. By combining the age bins from six RECS surveys and seventeen AHS surveys with shipments data, DOE had enough data to build a fit to a Weibull distribution and find the parameters (α, β, θ) that best approximate the surviving units, using a least-squares method. Because the first two (youngest) RECS bin data tend to have a large scatter relative to the shipments in those years, DOE combined the RECS and shipments data in the first two bins. Generally, appliances do not tend to fail in large numbers during this period, so combining bins does not appreciably lower the accuracy of the shape of the distribution. DOE weighted each bin's contribution to the sum of squares by the inverse of the variance in the survey results, which controls for the changes in sample size between RECS bins, between RECS and AHS, and within each survey over time. RECS and AHS have complicated error models; DOE used only the error due to finite sample size to determine the variance used to weight each data point's contribution. The error due to sampling is less than 1 percent for AHS survey data and is typically about 5 percent for RECS age bins. The equation for the sum of squares DOE minimized is therefore:

$$\sum_i \frac{\left(\boldsymbol{RECS}_i - \boldsymbol{Surv}_i\right)^2}{\sigma^2_{i,RECS}} + \sum_j \frac{\left(\boldsymbol{AHS}_j - \boldsymbol{Surv}_j\right)^2}{\sigma^2_{j,AHS}}$$

Eq. 8F.2

Where:

i = the identifier for a bin from a single RECS survey,

j = the identifier for a single AHS survey,
$RECS_i$ = the number of appliances reported by RECS in bin i,
AHS_j = the number of appliances reported by AHS in survey year j,
$Surv_i$ = the number of surviving appliances in bin i predicted by the Weibull distribution applied to the number of appliances shipped (a function of α, β, and θ),
$\sigma_{i,RECS}$ = the standard error (square root of the variance) of the RECS data point for bin i, and
$\sigma_{j,AHS}$ = the standard error (square root of the variance) of the AHS data point for year j.

DOE adjusted the RECS and AHS survey data in several ways to align the timing of the survey data with the historical shipment data. In particular, DOE adjusted for the fact that the RECS survey is scaled to July of its reference year, the AHS survey is conducted in the middle portion of the year, and shipment data is provided for each calendar year. Adjustments included:

- DOE modeled the additional retirement of older appliances and their replacement by new ones that took place in the latter half of the survey year (after a given respondent had been surveyed), using the survival function. This had the effect of moving households from the older RECS age bins to the youngest age bin.
- For appliances installed directly in new construction, such as boilers, DOE added units to the youngest RECS age bin and to the AHS total stock to represent half of the new construction for the final year of the survey, which were known to have installed the appliance type in question, using data from the U.S. Census for new construction starts.

8F.3.1 Assumptions

DOE's lifetime-calculation technique depends on several assumptions:

- Appliance lifetime can be modeled by a survival function. In particular, a Weibull distribution is an appropriate survival function.
- The appliance survival function does not change over time.
- The survival function is independent of other household factors (such as household size, region, *etc.*) as well as product class (within boilers).
- The age bin for the appliance as reported by the RECS respondent is correct.
- The historical shipment data is correct.
- The Weibull delay parameter, θ, is limited to between 1 and 5 years.

Three of these assumptions are of particular importance. The first is the assumption that a Weibull distribution is the correct distribution to use for appliance retirement rates. This distribution is the standard distribution for use in lifetime analysis, but it is not guaranteed to reflect actual consumer behavior. The second assumption is that consumer behavior and mechanical appliance lifetime have not changed over time. This assumption required DOE to treat all data from different RECS surveys on an equal footing. Using only recent surveys (to

potentially better reflect recent consumer behavior and appliance lifetime) would result in attempted least-squares fits using a small number of data points, leading to large statistical uncertainty.

DOE limited the delay parameter to between 1 and 5 years to reflect the range of common appliance warranties. A delay of less than 1 year would imply that some appliances fail or are replaced within their initial year of use, a period during which they are commonly covered by parts and labor warranties. A delay of greater than 5 years implies that no appliances are replaced for some length of time after the end of the longest standard warranty. Fits with $\theta > 5$ also commonly show nonsensical behavior with sharp changes in consumer behavior or appliance survival immediately following the "delay" period.

8F.3.2 Results

For the final rule, DOE used the AHRI contractor survey data to disaggregate the lifetimes for the different product classes by scaling the scale factor in the Weibull lifetime distribution determined for gas-boilers by the method described above and assuming the other parameters remain unchanged as shown in Table 8F.3.2. Electric boiler lifetimes are assumed to be the same as gas-fired boiler lifetimes.

Table 8F.3.1 Lifetime Parameters for Residential Boilers

Product Class	Weibull Parameters		AHRI Survey		Lifetime	
	Alpha (scale)	Beta (shape)	Location (delay)	Average	Average	Median
Calculated Gas Boiler Lifetime	**28.51**	**2.39**	**1.00**	**-**	**26.28**	**25.46**
Gas-Fired Hot Water Boiler	28.87	2.39	1.00	25.17	26.50	25.55
Gas-Fired Steam Boiler	25.51	2.39	1.00	22.19	23.38	22.72
Oil-Fired Hot Water Boiler	26.77	2.39	1.00	23.31	24.84	24.15
Oil-Fired Steam Boiler	20.63	2.39	1.00	17.87	19.25	18.68
Electric Hot Water Boiler	28.87	2.39	1.00	-	26.50	25.55
Electric Steam Boiler	25.51	2.39	1.00	-	23.38	22.72

8F.4 SENSITIVITY ANALYSIS

Currently, DOE does not have sufficient data to justify different lifetimes for non-condensing and condensing boilers. Boiler lifetime is not only affected by material and design characteristics, but also by the choices of consumers, who may replace a boiler before the product fails. Because the market share of condensing boilers only started to increase after 2003, it is unlikely that DOE's lifetime data includes many condensing to condensing boiler replacements.

DOE conducted a sensitivity analysis for its lifetime estimates to assess the impact of varying boiler lifetime on consumer LCC savings. DOE derived alternative low and high lifetime values based on the high and low values used in the 2007 Final Rule Rulemaking[24] and applied it to the LCC and PBP analysis. Data from the literature review discussed in section 8F.2 also points to alternative lifetime estimates of between 20 and 30 years. Table 8F.4.1 lists the average and median lifetime values for the high (30 years), low (20 years), and reference scenarios by product class.

Table 8F.4.1 Residential Boilers Average and Median Lifetime Values for Sensitivity Analysis

Product Class	Reference		High (30 Year)		Low (20 Year)	
	Average	Median	Average	Median	Average	Median
Calculated Gas Boiler Lifetime	**26.28**	**25.46**	**30.00**	**29.07**	**20.00**	**19.39**
Gas-Fired Hot Water Boiler	26.50	25.55	30.31	29.37	20.31	19.69
Gas-Fired Steam Boiler	23.38	22.72	27.33	26.48	17.33	16.81
Oil-Fired Hot Water Boiler	24.84	24.15	28.45	27.57	18.45	17.89
Oil-Fired Steam Boiler	19.25	18.68	23.01	22.30	13.01	12.63

The results of the lifetime sensitivity analysis are shown in Table 8F.4.2 through Table 8F.4.5 for the low and high lifetime scenarios. In the first of each pair of tables, the simple payback is measured relative to the baseline equipment. In the second of each pair of tables, the impacts are measured relative to the efficiency distribution in the no-new-standards case in the compliance year (2021). The summary Table 8F.4.6 shows a comparison of the lifetime sensitivity LCC results and the reference case LCC results. As shown in Table 8F.4.6, the LCC savings in the low lifetime scenario are lower than in the reference case, and the LCC savings are in the high lifetime scenario are higher than in the reference case. In general, the LCC savings at condensing efficiency levels are impacted more from the alternative lifetime values because condensing boilers have a higher total installed cost compared to non-condensing boilers, which is more difficult to recover through decreased energy use over the shorter boiler lifetime. The simple PBPs of the reference lifetime are slightly lower than low lifetime scenario and are slightly higher than the high lifetime scenario because lifetime impacts the installation cost for households requiring chimney resizing or vent relining (see appendix 8C). The sensitivity analysis results demonstrate that the LCC savings and payback period for non-condensing efficiency levels are less sensitive to the lifetime value compared to condensing efficiency levels.

Table 8F.4.2 Low Lifetime Scenario (20 year average): Average LCC and PBP Results

Product Class	EL	Average Costs (2014$)				Simple Payback *years*	Average Lifetime *years*
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
Gas-Fired Hot Water Boilers	0	$6,261	$1,224	$18,324	$24,585	NA	20.3
	1	$6,276	$1,211	$18,132	$24,408	1.2	20.3
	2	$6,292	$1,198	$17,944	$24,236	1.2	20.3
	3	$6,579	$1,186	$17,774	$24,353	8.6	20.3
	4	$7,231	$1,119	$16,760	$23,991	9.2	20.3
	5	$7,581	$1,098	$16,463	$24,044	10.6	20.3
	6	$8,271	$1,061	$15,904	$24,175	12.4	20.3
Gas-Fired Steam Boilers	0	$6,120	$1,087	$14,227	$20,347	NA	17.3
	1	$6,189	$1,063	$13,922	$20,111	2.9	17.3
	2	$6,505	$1,052	$13,778	$20,282	11.1	17.3
Oil-Fired Hot Water Boilers	0	$7,894	$2,021	$30,282	$38,176	NA	18.5
	1	$8,045	$1,999	$29,950	$37,996	6.9	18.5
	2	$8,196	$1,969	$29,491	$37,688	5.8	18.5
	3	$10,671	$1,861	$27,855	$38,525	17.3	18.5
Oil-Fired Steam Boilers	0	$7,816	$1,973	$21,421	$29,237	NA	13.0
	1	$8,119	$1,927	$20,923	$29,042	6.6	13.0
	2	$8,271	$1,905	$20,683	$28,954	6.7	13.0
	3	$8,575	$1,876	$20,358	$28,932	7.8	13.0

Note: The results for each TSL are calculated assuming that all consumers use products at that efficiency level. The PBP is measured relative to the baseline equipment.

Table 8F.4.3 Low Lifetime Scenario (20 year average): LCC Savings Relative to the No-New-Standards Case Efficiency Distribution

Product Class	EL	% of Consumers that Experience Net Cost	Average LCC Savings* *2014$*
Gas-Fired Hot Water Boilers	0	0.0%	NA
	1	0.5%	$166
	2	0.5%	$288
	3	14.7%	$45
	4	25.1%	$241
	5	33.8%	$128
	6	64.8%	($56)
Gas-Fired Steam Boilers	0	0.0%	NA
	1	1.0%	$241
	2	40.4%	$63
Oil-Fired Hot Water Boilers	0	0.0%	NA
	1	13.8%	$166
	2	12.6%	$427
	3	69.5%	($554)
Oil-Fired Steam Boilers	0	0.0%	NA
	1	18.5%	$194
	2	30.5%	$208
	3	49.0%	$189

* The savings represent the average LCC for affected consumers

Table 8F.4.4 High Lifetime Scenario (30 year average): Average LCC and PBP Results

Product Class	EL	Average Costs (2014$)				Simple Payback *years*	Average Lifetime *years*
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
Gas-Fired Hot Water Boilers	0	$6,433	$1,224	$25,126	$31,559	NA	30.3
	1	$6,449	$1,211	$24,862	$31,311	1.2	30.3
	2	$6,465	$1,198	$24,605	$31,069	1.2	30.3
	3	$6,687	$1,186	$24,370	$31,056	6.8	30.3
	4	$7,268	$1,119	$22,967	$30,235	7.9	30.3
	5	$7,618	$1,098	$22,560	$30,178	9.5	30.3
	6	$8,308	$1,061	$21,794	$30,102	11.5	30.3
Gas-Fired Steam Boilers	0	$6,470	$1,087	$20,493	$26,963	NA	27.3
	1	$6,530	$1,063	$20,054	$26,584	2.5	27.3
	2	$6,830	$1,052	$19,846	$26,675	10.4	27.3
Oil-Fired Hot Water Boilers	0	$8,142	$2,021	$43,909	$52,051	NA	28.5
	1	$8,293	$1,999	$43,426	$51,718	6.9	28.5
	2	$8,444	$1,969	$42,759	$51,203	5.8	28.5
	3	$10,705	$1,861	$40,363	$51,067	16.0	28.5
Oil-Fired Steam Boilers	0	$7,995	$1,973	$35,225	$43,221	NA	23.0
	1	$8,299	$1,928	$34,404	$42,703	6.6	23.0
	2	$8,451	$1,906	$34,009	$42,460	6.7	23.0
	3	$8,754	$1,876	$33,474	$42,228	7.8	23.0

Note: The results for each TSL are calculated assuming that all consumers use products at that efficiency level. The PBP is measured relative to the baseline equipment.

Table 8F.4.5 High Lifetime Scenario (30 year average): LCC Savings Relative to the No-New-Standards Case Efficiency Distribution

Product Class	EL	% of Consumers that Experience Net Cost	Average LCC Savings* *2014$*
Gas-Fired Hot Water Boilers	0	0.0%	NA
	1	0.3%	$233
	2	0.3%	$405
	3	12.0%	$264
	4	20.4%	$856
	5	27.0%	$733
	6	51.0%	$505
Gas-Fired Steam Boilers	0	0.0%	NA
	1	0.8%	$390
	2	27.2%	$289
Oil-Fired Hot Water Boilers	0	0.0%	NA
	1	9.0%	$313
	2	7.8%	$740
	3	53.8%	$624
Oil-Fired Steam Boilers	0	0.0%	NA
	1	9.8%	$516
	2	16.1%	$562
	3	28.9%	$683

* The savings represent the average LCC for affected consumers

Table 8F.4.6 Comparison Average LCC Savings, Percent of Consumers that Experience Net Cost, and Simple Payback Period Results for Reference, Low, and High Lifetime Scenarios

Product Class	EL	Average LCC Savings *2014$*			% of Consumers that Experience Net Cost *%*			Simple Payback Period *Years*		
		Ref	Low	High	Ref	Low	High	Ref	Low	High
Gas-fired Hot Water Boiler	1	$210	$166	$233	0.3%	0.5%	0.3%	1.2	1.2	1.2
	2	$364	$288	$405	0.4%	0.5%	0.3%	1.2	1.2	1.2
	3	$182	$45	$264	13.0%	14.7%	12.0%	7.5	8.6	6.8
	4	$632	$241	$856	21.9%	25.1%	20.4%	8.4	9.2	7.9
	5	$513	$128	$733	29.2%	33.8%	27.0%	9.9	10.6	9.5
	6	$303	($56)	$505	55.5%	64.8%	51.0%	11.8	12.4	11.5
Gas-fired Steam Boiler	1	$333	$241	$390	0.9%	1.0%	0.8%	2.7	2.9	2.5
	2	$207	$63	$289	30.8%	40.4%	27.2%	10.7	11.1	10.4
Oil-fired Hot Water Boiler	1	$260	$166	$313	10.4%	13.8%	9.0%	6.9	6.9	6.9
	2	$626	$427	$740	8.8%	12.6%	7.8%	5.8	5.8	5.8
	3	$192	($554)	$624	58.9%	69.5%	53.8%	16.5	17.3	16.0
Oil-fired Steam Boiler	1	$400	$194	$516	11.9%	18.5%	9.8%	6.6	6.6	6.6
	2	$434	$208	$562	19.7%	30.5%	16.1%	6.7	6.7	6.7
	3	$505	$189	$683	34.2%	49.0%	28.9%	7.8	7.8	7.8

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APPENDIX 8G. DISTRIBUTIONS USED FOR DISCOUNT RATES

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APPENDIX 8G. DISTRIBUTIONS USED FOR DISCOUNT RATES

8G.1 INTRODUCTION

The Department of Energy (DOE) estimated discount rate distributions by customer type: commercial and consumer (*i.e.* non-commercial residential end user). This appendix describes the distributions used.

8G.2 DISTRIBUTIONS USED FOR CONSUMER DISCOUNT RATES

The Department of Energy (DOE) derived consumer discount rates for the life-cycle cost (LCC) analysis using data on interest or return rates for various types of debt and equity to calculate a real effective discount rate for each household in the Federal Reserve Board's *Survey of Consumer Finances (SCF)* in 1995, 1998, 2001, 2004, 2007, 2010, and 2013.[1] To account for variation among households in rates for each of the types, DOE sampled a rate for each household in its building sample from a distribution of discount rates for each of six income groups. This appendix describes the distributions used.

8G.2.1 Distribution of Rates for Debt Classes

Figure 8G.2.1 through Figure 8G.2.6 show the distribution of real interest rates for different types of household debt. The data source for the interest rates for mortgages, home equity loans, credit cards, installment loans, other residence loans, and other lines of credit is the Federal Reserve Board's *SCF* in 1995, 1998, 2001, 2004, 2007, 2010 and 2013. DOE adjusted the nominal rates to real rates using the annual inflation rate in each year.

Using the appropriate *SCF* data for each year, DOE adjusted the nominal mortgage interest rate and the nominal home equity loan interest rate for each relevant household in the *SCF* for mortgage tax deduction and inflation. In cases where the effective interest rate is equal to or below the inflation rate (resulting in a negative real interest rate), DOE set the real effective interest rate to zero.

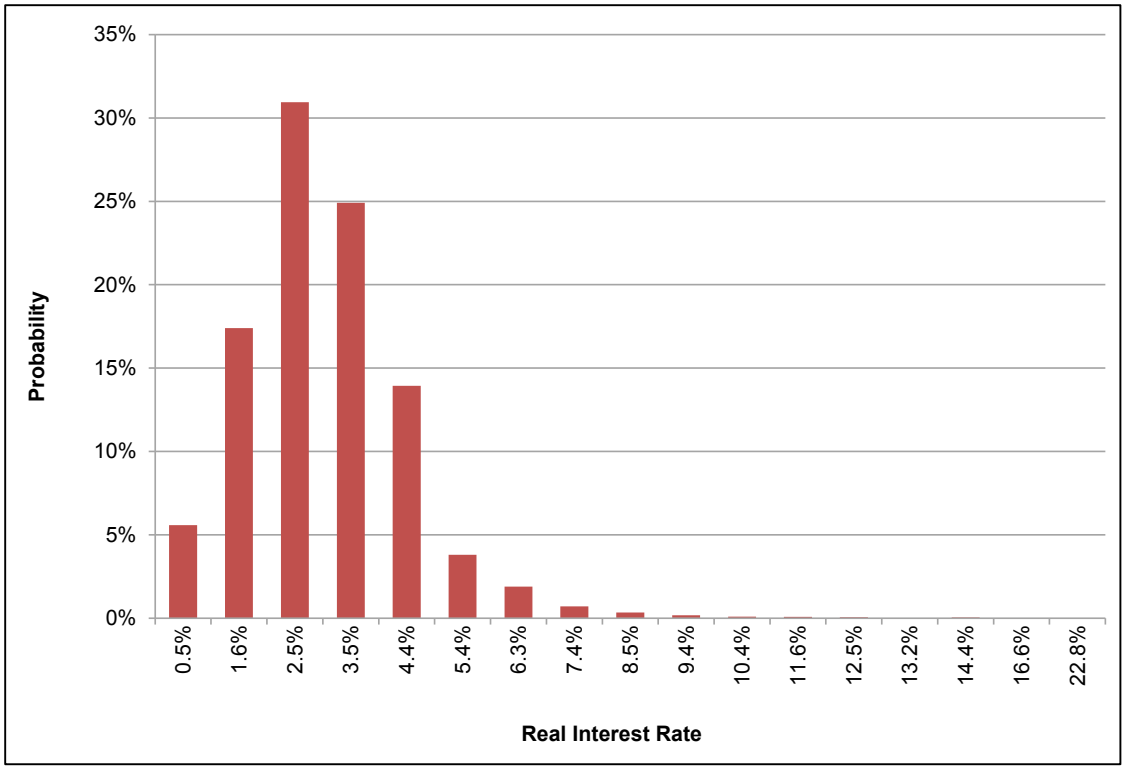

Figure 8G.2.1 Distribution of Mortgage Interest Rates

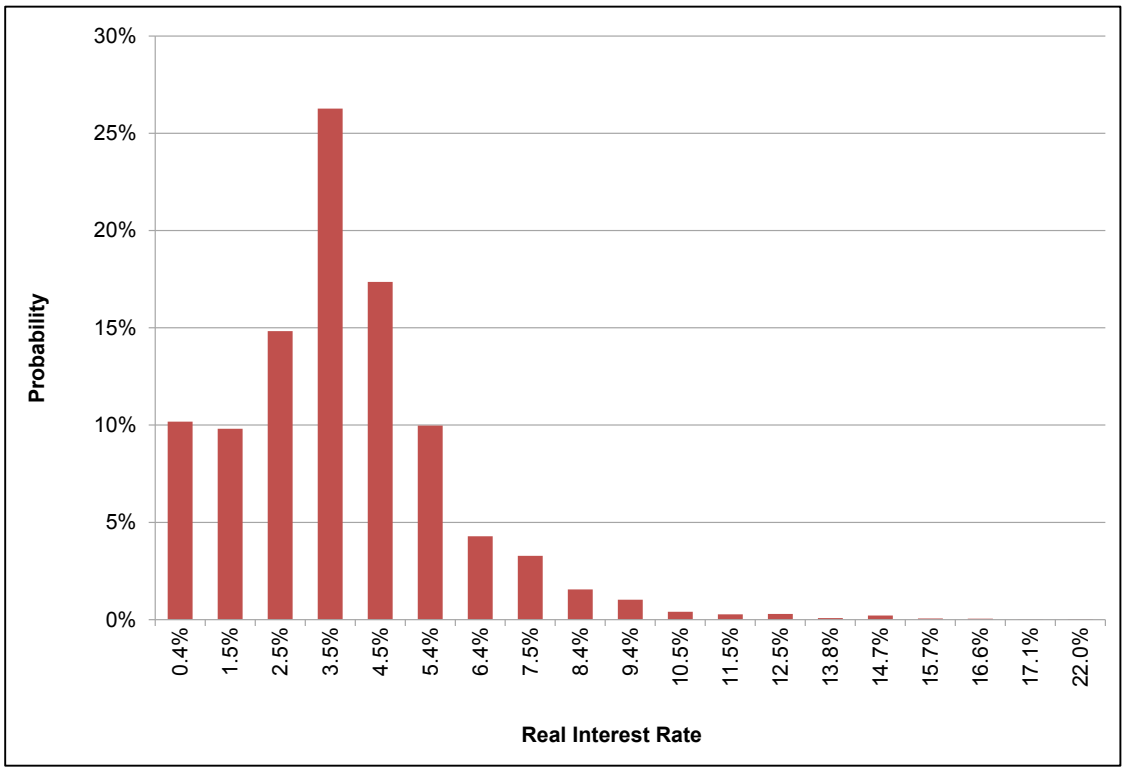

Figure 8G.2.2 Distribution of Home Equity Loan Interest Rates

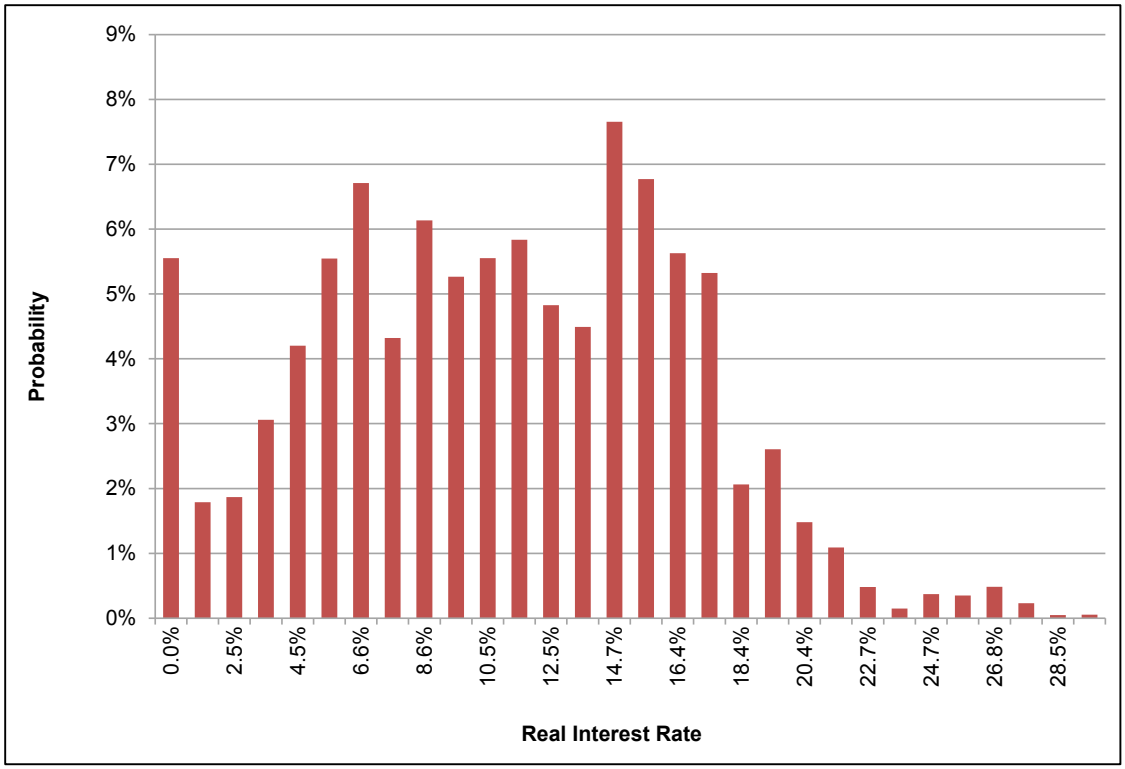

Figure 8G.2.3 Distribution of Credit Card Interest Rates

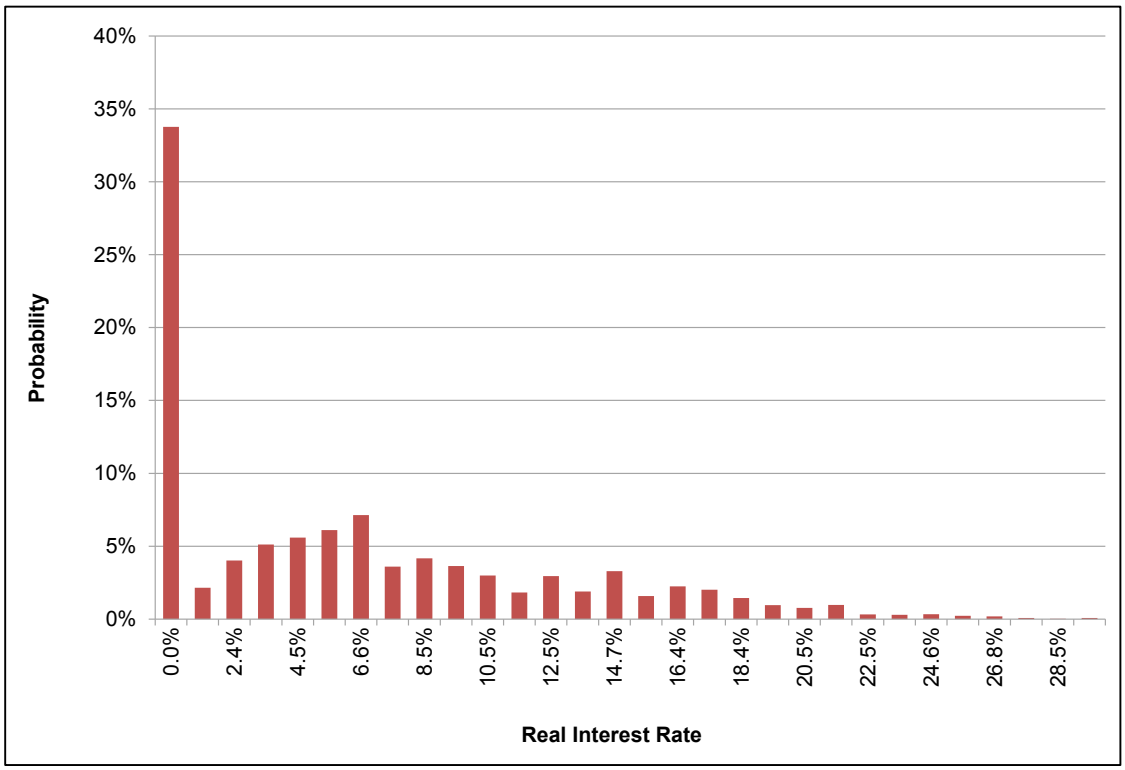

Figure 8G.2.4 Distribution of Installment Loan Interest Rates

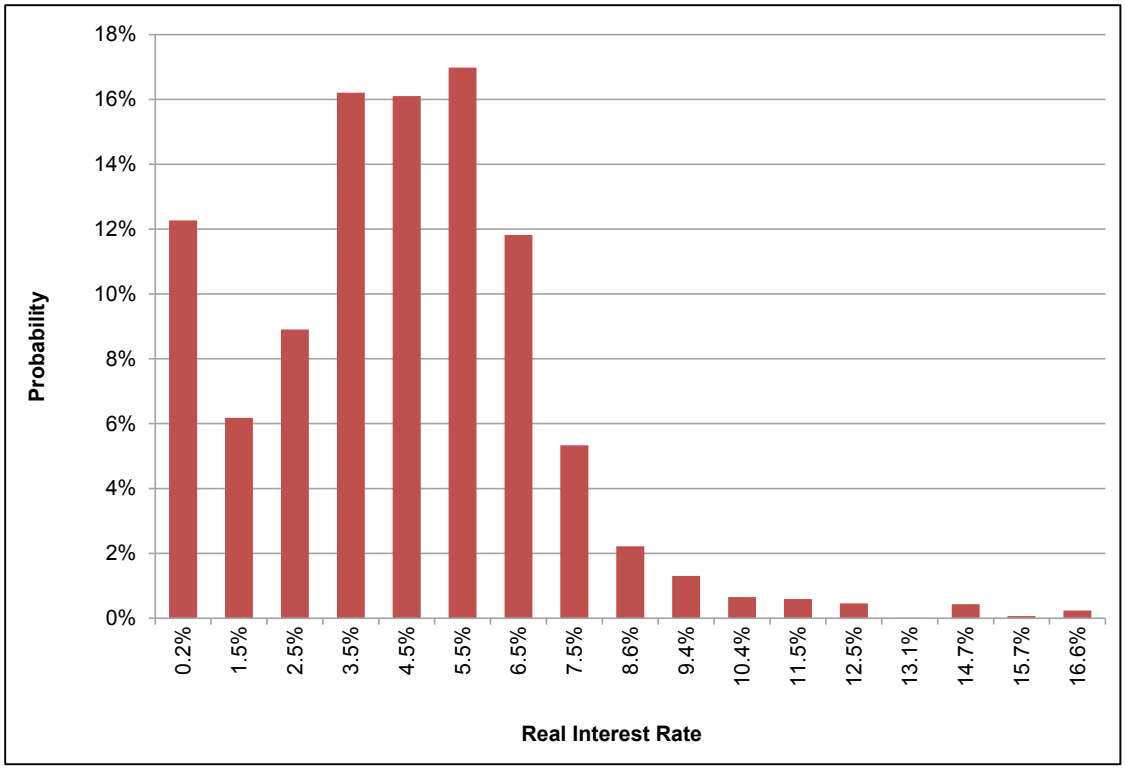

Figure 8G.2.5 Distribution of Other Residence Loan Interest Rates

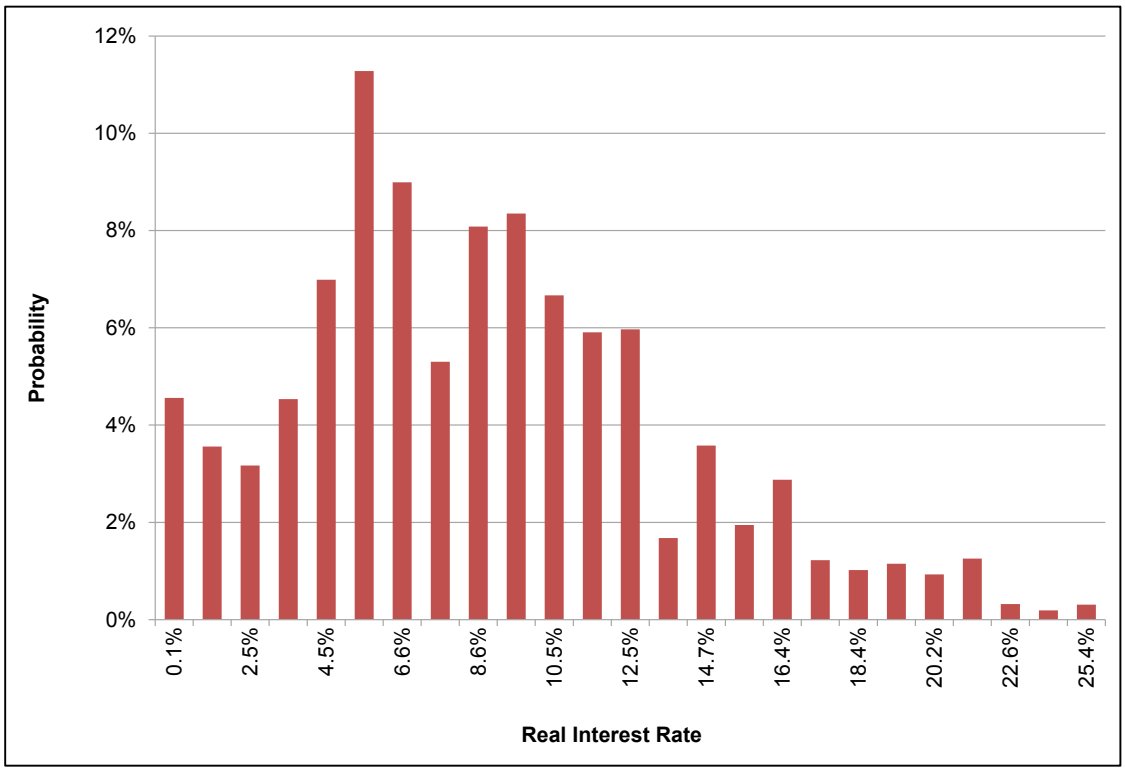

Figure 8G.2.6 Distribution of Other Lines of Credit Loan Interest Rates

8G.2.2 Distribution of Rates for Equity Classes

Figure 8G.2.7 through Figure 8G.2.12 show the distribution of real interest rates for different types of equity. Data for equity classes are not available from the Federal Reserve Board's *SCF*, so DOE derived data for these classes from national-level historical data (1986-2014). The interest rates associated with certificates of deposit (CDs),[2] savings bonds,[3] and AAA corporate bonds[4] are from Federal Reserve Board time-series data. DOE assumed rates on checking accounts to be zero. Rates on savings and money market accounts are from Cost of Savings Index data.[5] The rates for stocks are the annual returns on the Standard and Poor's (S&P) 500.[6] The mutual fund rates are a weighted average of the stock rates (two-thirds weight) and the bond rates (one-third weight) in each year. DOE adjusted the nominal rates to real rates using the annual inflation rate in each year.

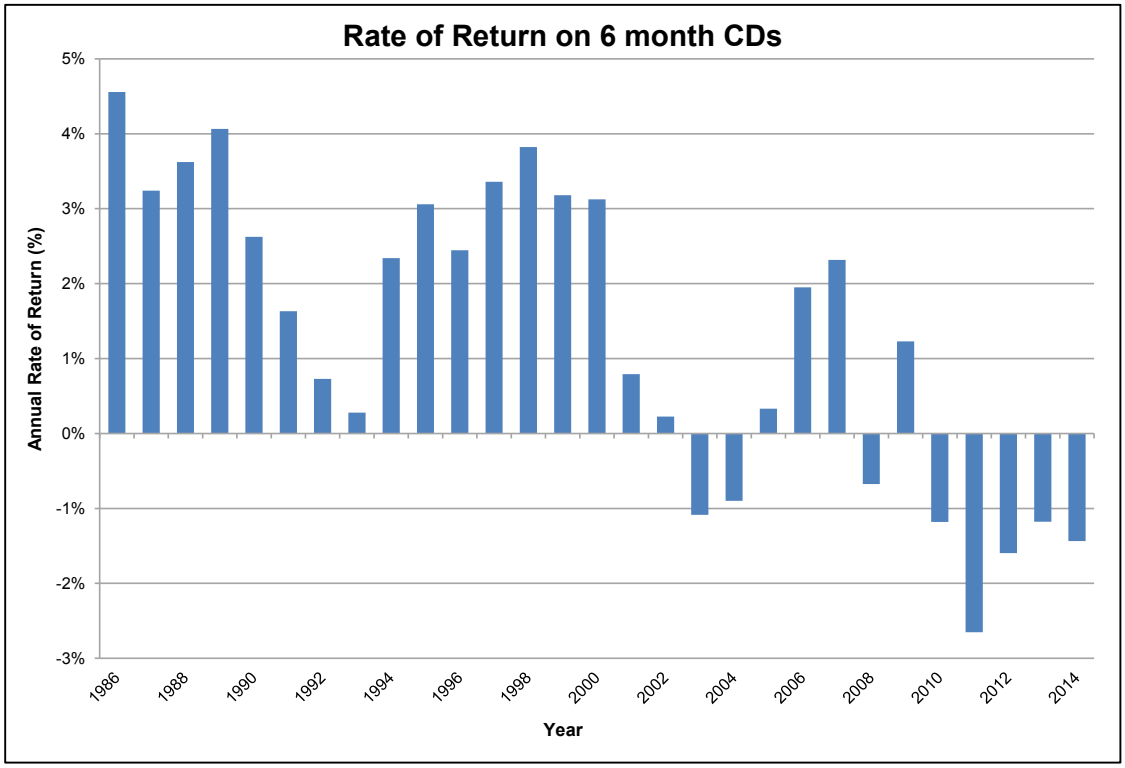

Figure 8G.2.7 Distribution of Annual Rate of Return on CDs

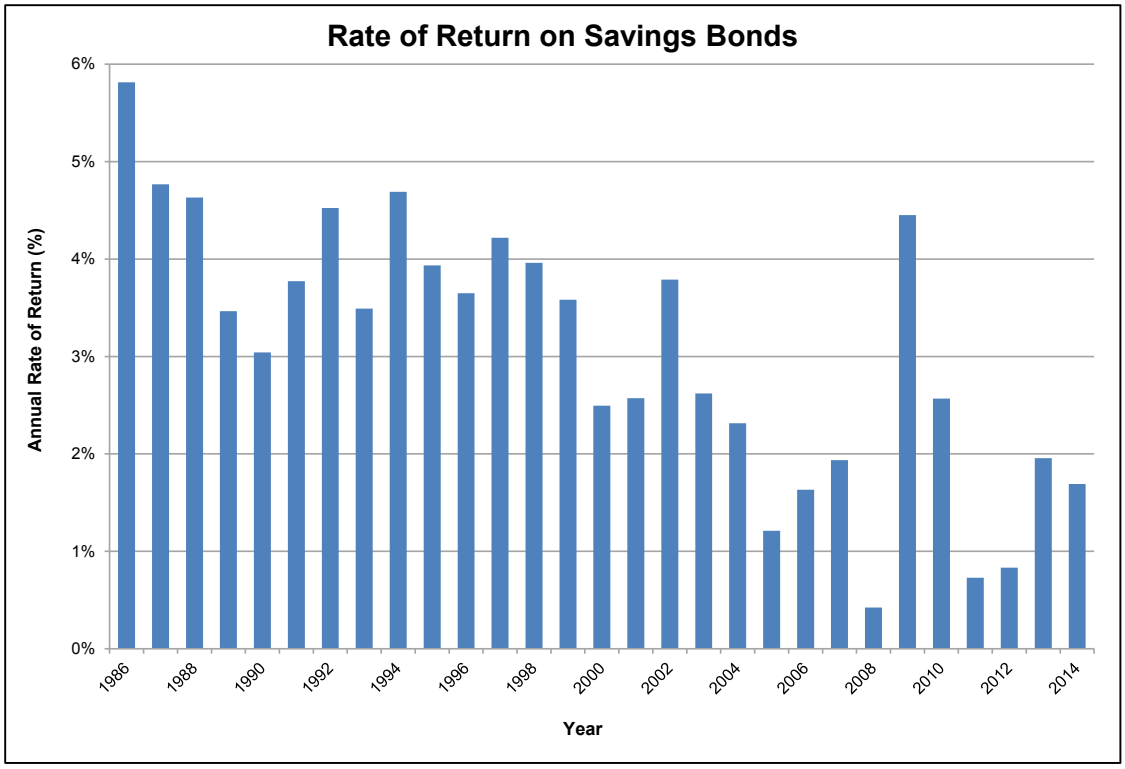

Figure 8G.2.8 Distribution of Annual Rate of Return on Savings Bonds

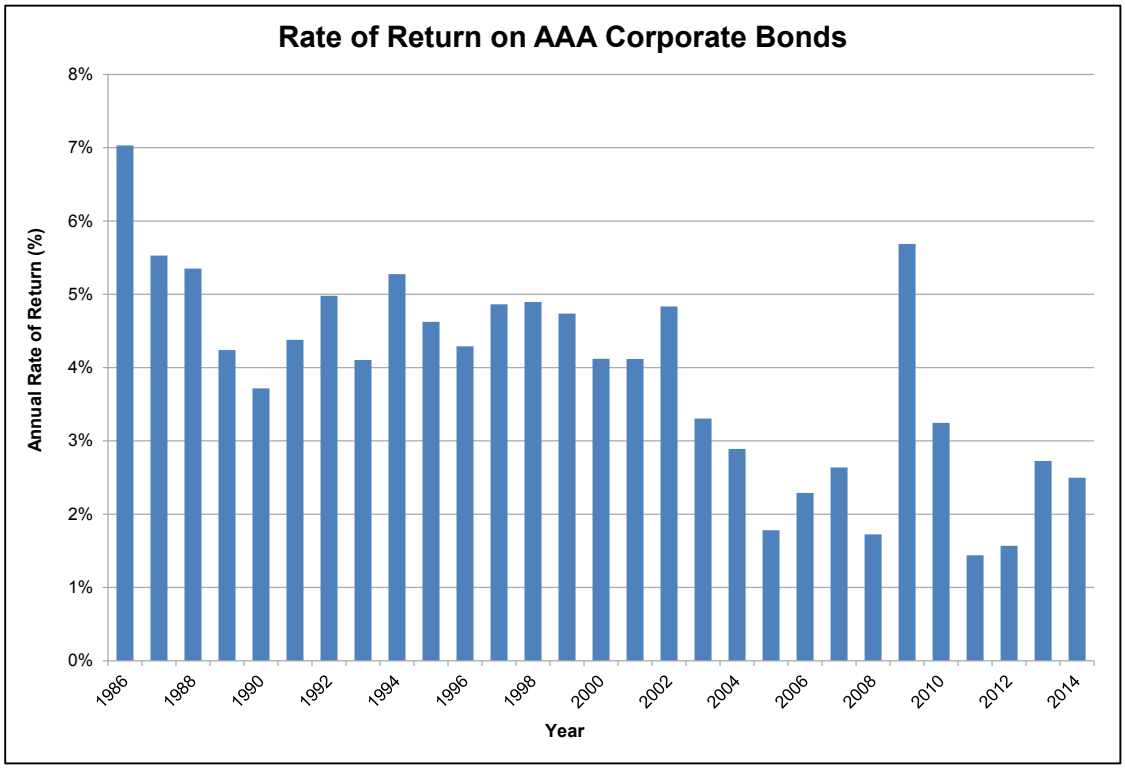

Figure 8G.2.9 Distribution of Annual Rate of Return on Corporate AAA Bonds

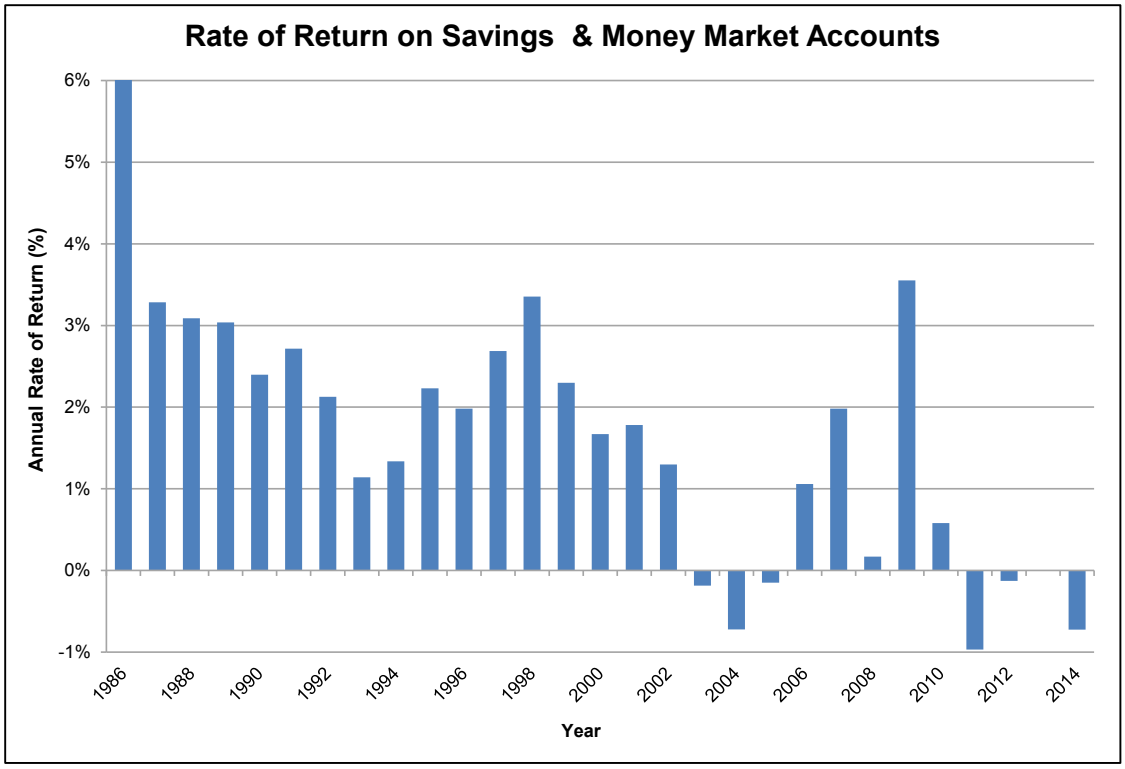

Figure 8G.2.10 Distribution of Annual Rate of Savings Accounts

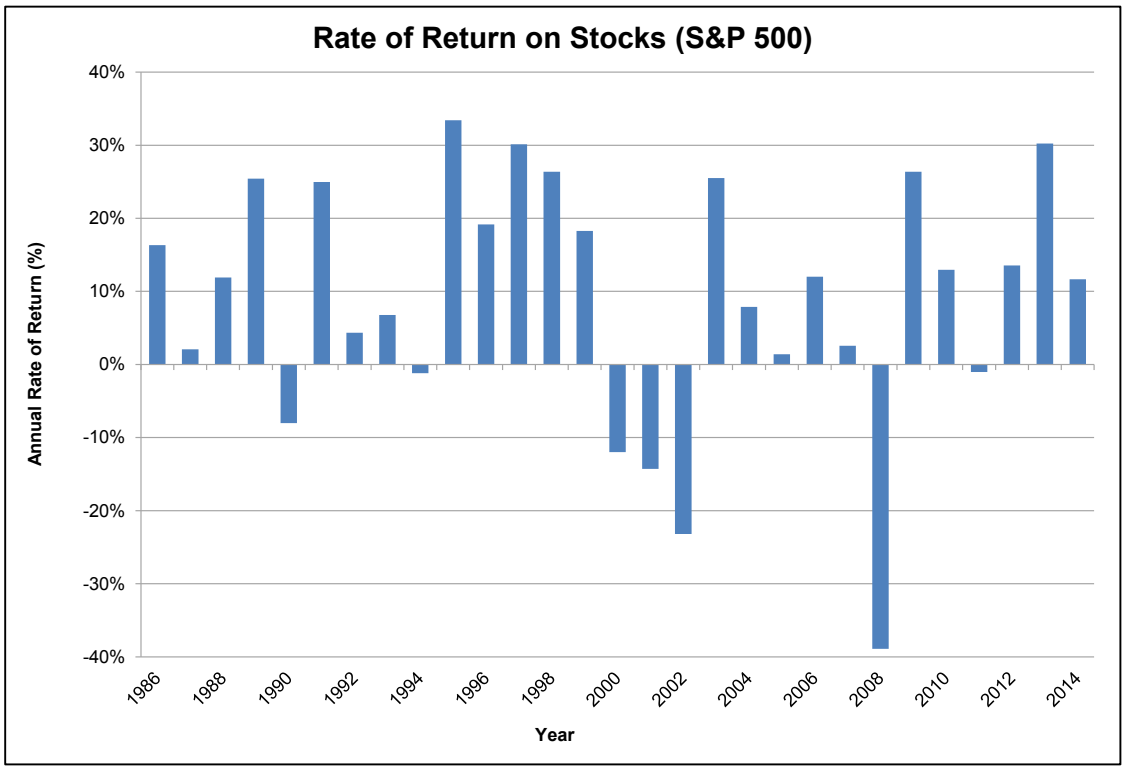

Figure 8G.2.11 Distribution of Annual Rate of Return on S&P 500

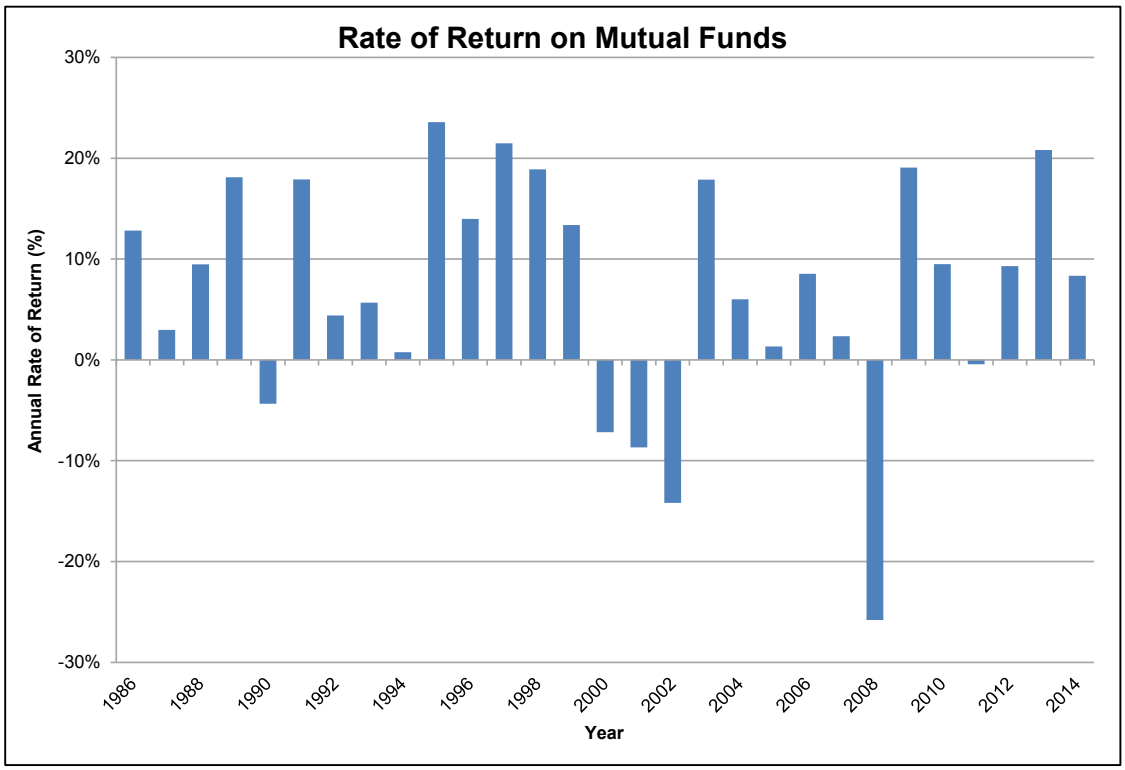

Figure 8G.2.12 Distribution of Annual Rate of Return on Mutual Funds

8G.2.3 Distribution of Real Effective Discount Rates by Income Group

Figure 8G.2.13 and Table 8G.2.1 present the distributions of real discount rates for each income group.

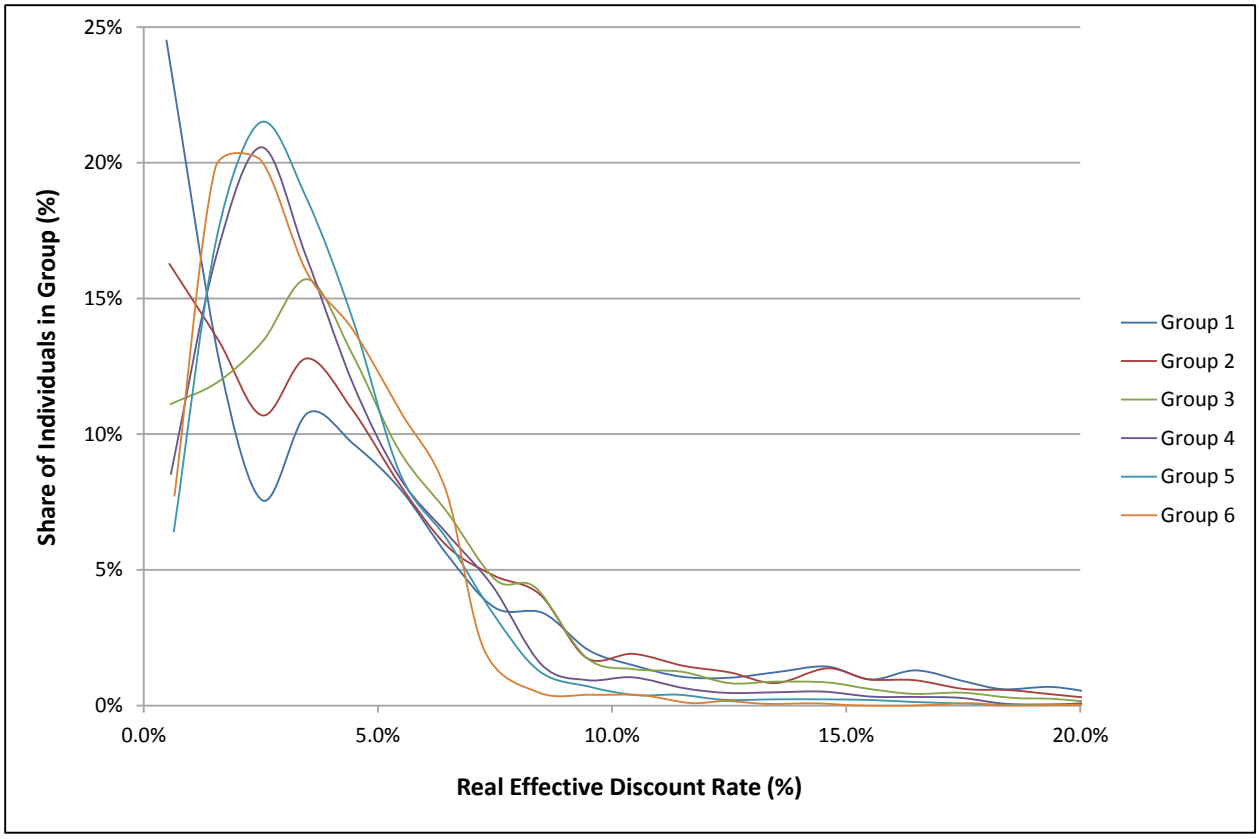

Figure 8G.2.13 Distribution of Real Discount Rates by Income Group

Table 8G.2.1 Distribution of Real Discount Rates by Income Group

DR Bin	Income Group 1 (1-20 percentile)		Income Group 2 (21-40 percentile)		Income Group 3 (41-60 percentile)		Income Group 4 (61-80 percentile)		Income Group 5 (81-90 percentile)		Income Group 6 (90-99 percentile)	
	rate	weight	rate	weight	rate	weight	rate	weight	rate	weight	rate	weight
0-1	0.5%	0.245	0.5%	0.163	0.6%	0.111	0.6%	0.085	0.6%	0.064	0.7%	0.077
1-2	1.6%	0.126	1.6%	0.134	1.6%	0.119	1.5%	0.165	1.6%	0.172	1.5%	0.198
2-3	2.5%	0.076	2.5%	0.107	2.5%	0.134	2.5%	0.206	2.5%	0.215	2.5%	0.201
3-4	3.5%	0.108	3.5%	0.128	3.5%	0.157	3.5%	0.165	3.5%	0.187	3.5%	0.160
4-5	4.5%	0.096	4.5%	0.109	4.5%	0.129	4.5%	0.118	4.5%	0.142	4.5%	0.138
5-6	5.5%	0.080	5.5%	0.081	5.5%	0.094	5.5%	0.084	5.5%	0.086	5.5%	0.108
6-7	6.5%	0.055	6.5%	0.059	6.5%	0.071	6.5%	0.063	6.5%	0.062	6.5%	0.079
7-8	7.5%	0.036	7.5%	0.048	7.5%	0.046	7.5%	0.044	7.5%	0.033	7.3%	0.020
8-9	8.5%	0.034	8.5%	0.041	8.4%	0.043	8.5%	0.015	8.5%	0.013	8.4%	0.005
9-10	9.5%	0.020	9.4%	0.018	9.5%	0.018	9.5%	0.009	9.5%	0.007	9.6%	0.004
10-11	10.5%	0.015	10.5%	0.019	10.5%	0.013	10.4%	0.010	10.5%	0.004	10.6%	0.004
11-12	11.5%	0.011	11.5%	0.015	11.5%	0.012	11.5%	0.006	11.4%	0.004	11.7%	0.001
12-13	12.5%	0.010	12.5%	0.012	12.5%	0.008	12.4%	0.005	12.4%	0.002	12.4%	0.002
13-14	13.5%	0.012	13.5%	0.008	13.5%	0.009	13.5%	0.005	13.5%	0.002	13.3%	0.001
14-15	14.6%	0.014	14.6%	0.014	14.6%	0.009	14.5%	0.005	14.6%	0.002	14.3%	0.001
15-16	15.5%	0.010	15.5%	0.010	15.5%	0.006	15.5%	0.003	15.5%	0.002	15.2%	0.000
16-17	16.5%	0.013	16.5%	0.009	16.4%	0.004	16.5%	0.003	16.4%	0.001	0.0%	0.000
17-18	17.5%	0.009	17.5%	0.006	17.5%	0.005	17.5%	0.003	17.6%	0.001	17.7%	0.001
18-19	18.4%	0.006	18.5%	0.006	18.5%	0.003	18.4%	0.001	18.2%	0.000	18.3%	0.000
19-20	19.4%	0.007	19.4%	0.004	19.4%	0.002	19.6%	0.001	19.7%	0.000	19.3%	0.000
20-21	20.6%	0.004	20.4%	0.003	20.4%	0.001	20.3%	0.001	20.5%	0.000	20.3%	0.000
21-22	21.4%	0.005	21.3%	0.002	21.4%	0.001	21.4%	0.001	0.0%	0.000	21.4%	0.000
22-23	22.4%	0.002	22.4%	0.001	22.6%	0.001	22.6%	0.000	22.8%	0.000	22.3%	0.000
23-24	23.5%	0.001	23.4%	0.001	23.5%	0.001	0.0%	0.000	0.0%	0.000	23.9%	0.000
24-25	24.6%	0.001	24.4%	0.000	24.6%	0.000	24.1%	0.000	24.3%	0.000	0.0%	0.000
25-26	25.4%	0.001	25.4%	0.001	25.4%	0.001	25.0%	0.000	0.0%	0.000	0.0%	0.000
26-27	26.4%	0.001	26.4%	0.000	26.3%	0.000	0.0%	0.000	0.0%	0.000	0.0%	0.000
27-28	27.5%	0.000	27.6%	0.000	27.5%	0.000	27.1%	0.000	27.1%	0.000	0.0%	0.000
28-29	28.1%	0.001	28.1%	0.000	0.0%	0.000	0.0%	0.000	0.0%	0.000	0.0%	0.000
29-23	29.9%	0.000	29.3%	0.000	0.0%	0.000	0.0%	0.000	0.0%	0.000	0.0%	0.000
>30	70.1%	0.001	162.1%	0.002	33.7%	0.000	53.3%	0.000	0.0%	0.000	0.0%	0.000

8G.3 DISTRIBUTIONS USED FOR COMMERCIAL DISCOUNT RATES

DOE derived commercial discount rates (*i.e.* weighted average cost of capital) for the life-cycle cost (LCC) analysis using the capital asset pricing model and firm-level data provided by Damodaran Online.[7] State and local government discount rates were estimated using the rate

of return on 20-year municipal bonds, as provided by the Federal Reserve Board.[3] Separate distributions were constructed for each major industry. Figure 8G.3.1 through Figure 8G.3.9 show the probability distributions of commercial discount rates by industry.

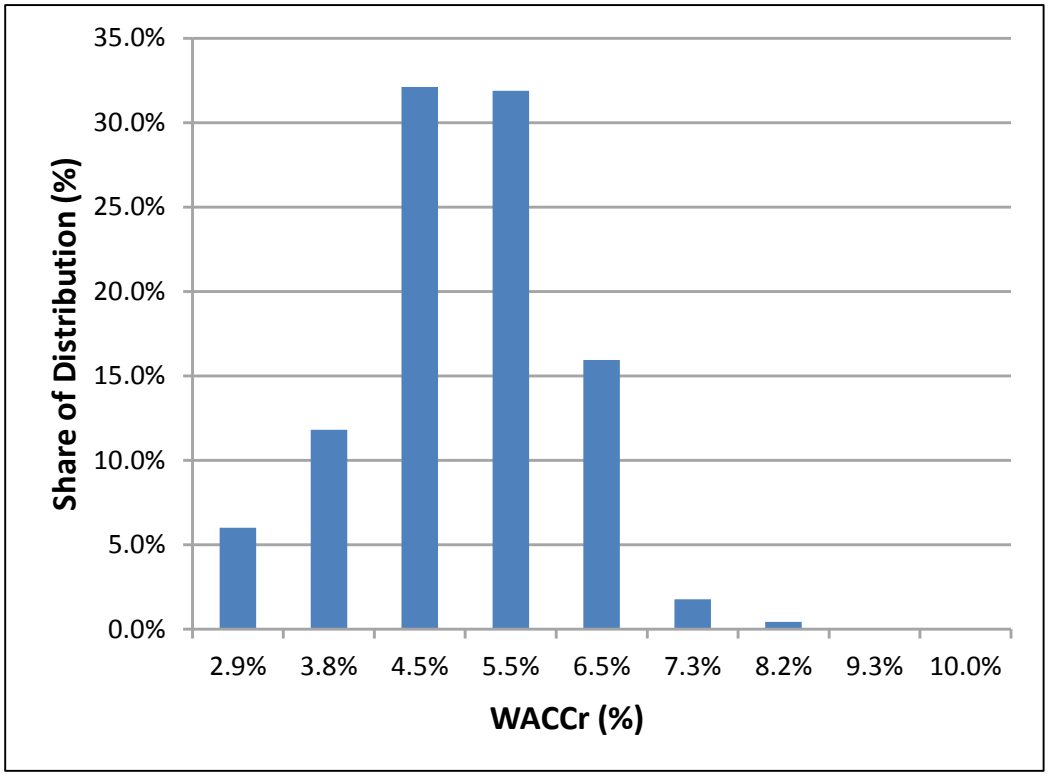

Figure 8G.3.1 Distribution of Commercial Discount Rates: Retail

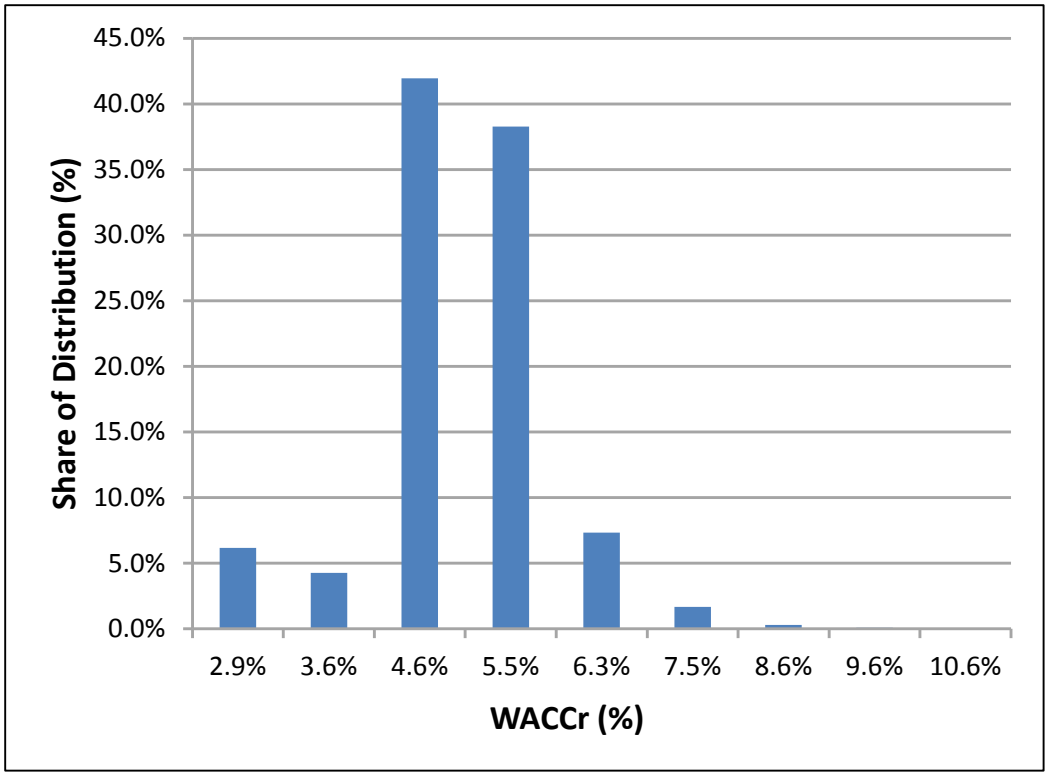

Figure 8G.3.2 Distribution of Commercial Discount Rates: Medical

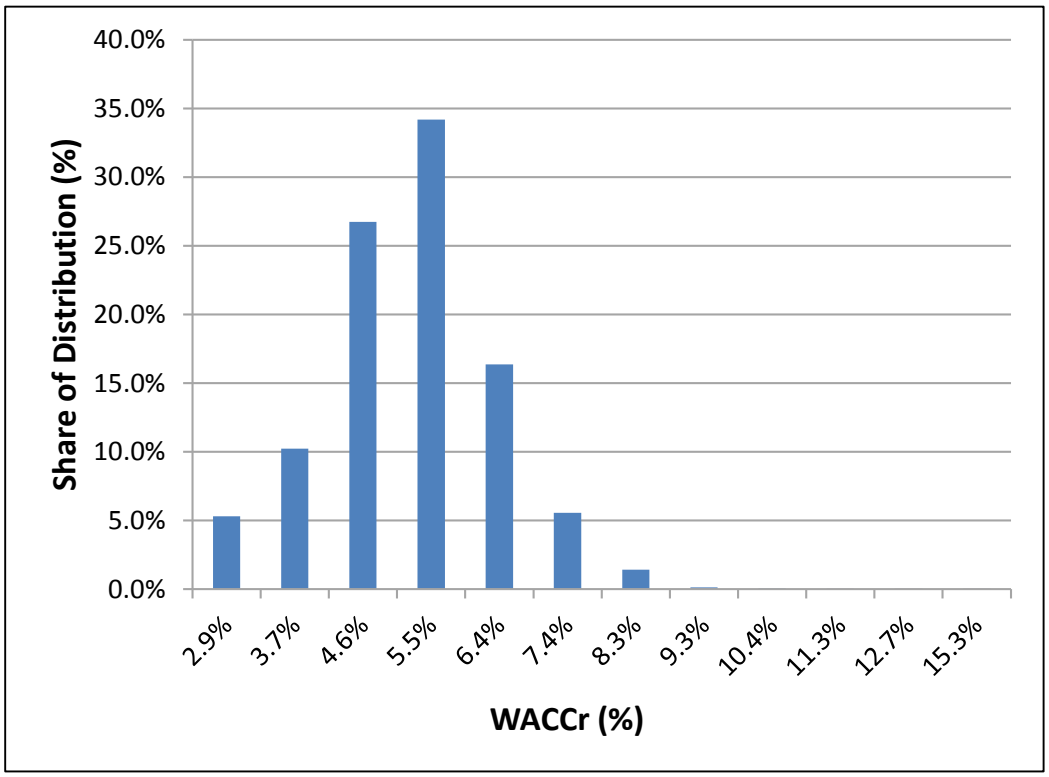

Figure 8G.3.3 Distribution of Commercial Discount Rates: Industrial

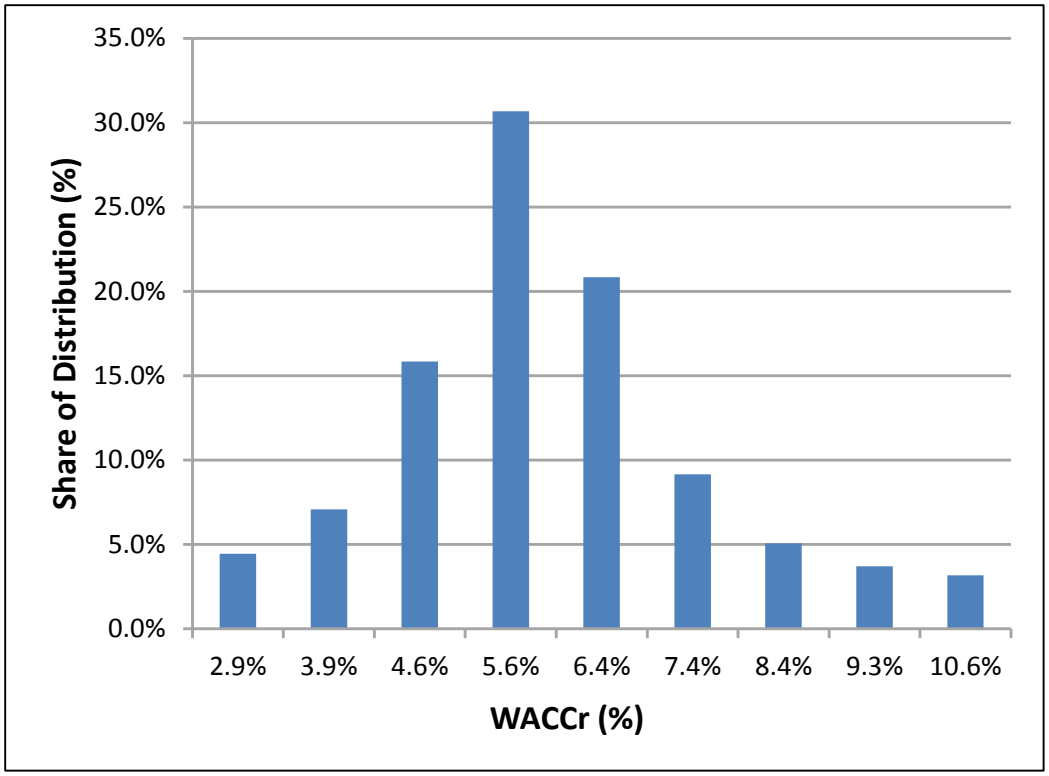

Figure 8G.3.4 Distribution of Commercial Discount Rates: Lodging

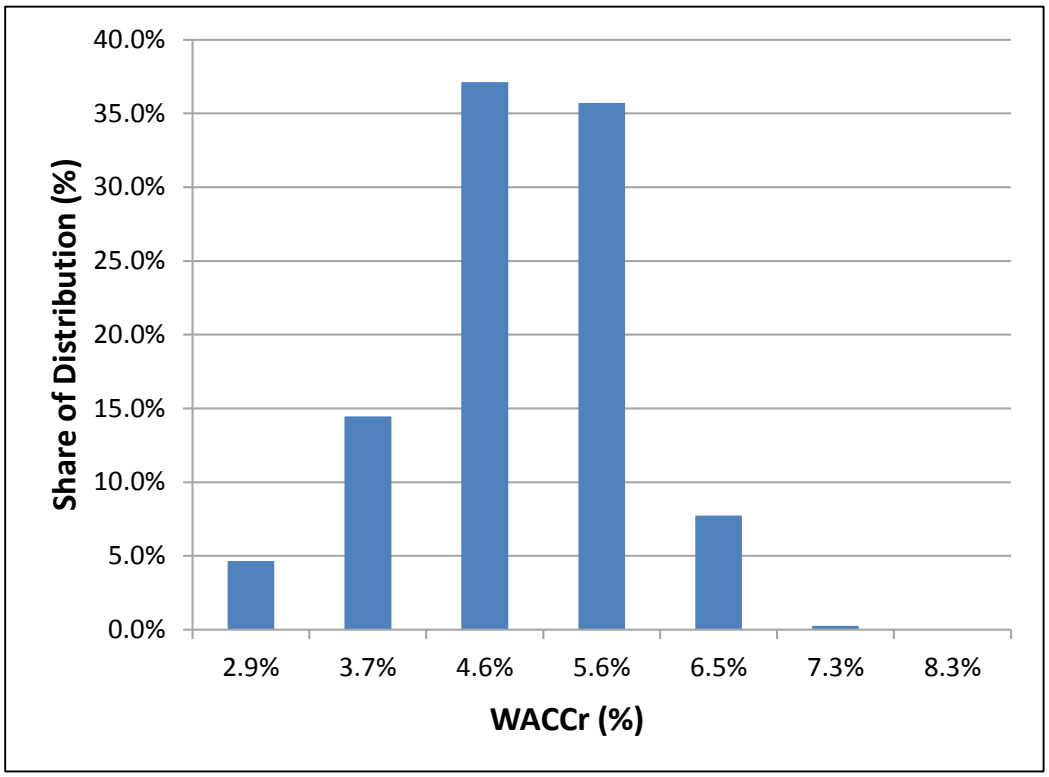

Figure 8G.3.5 Distribution of Commercial Discount Rates: Food Service

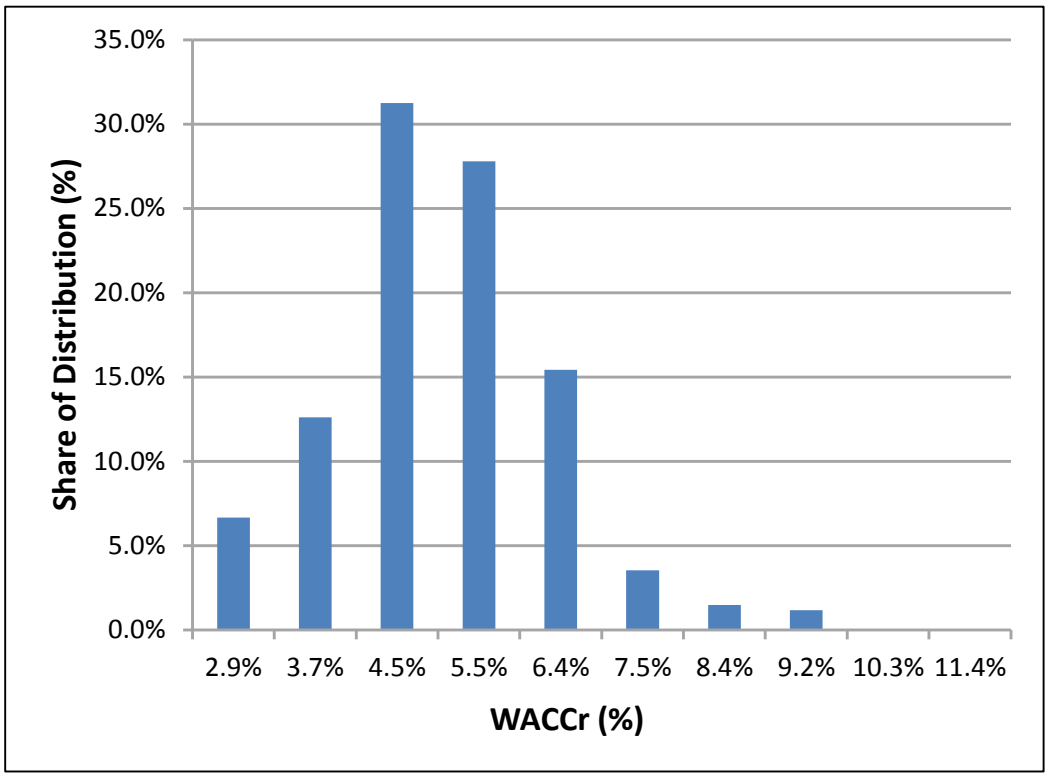

Figure 8G.3.6 Distribution of Commercial Discount Rates: Office

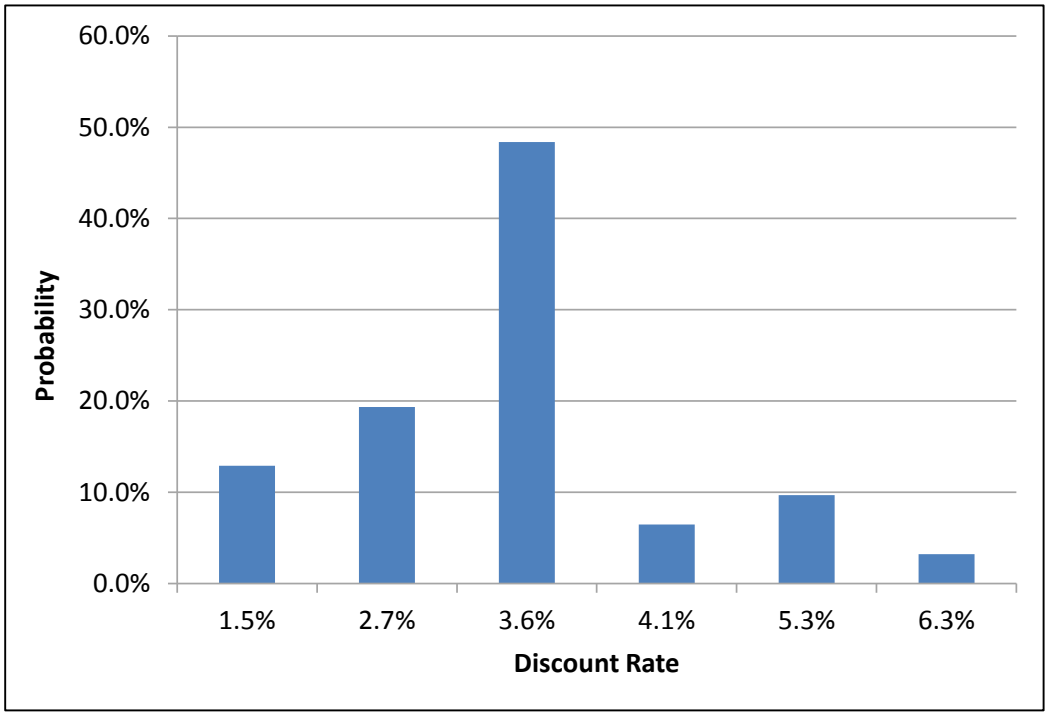

Figure 8G.3.7 Distribution of Commercial Discount Rates: State and Local Government

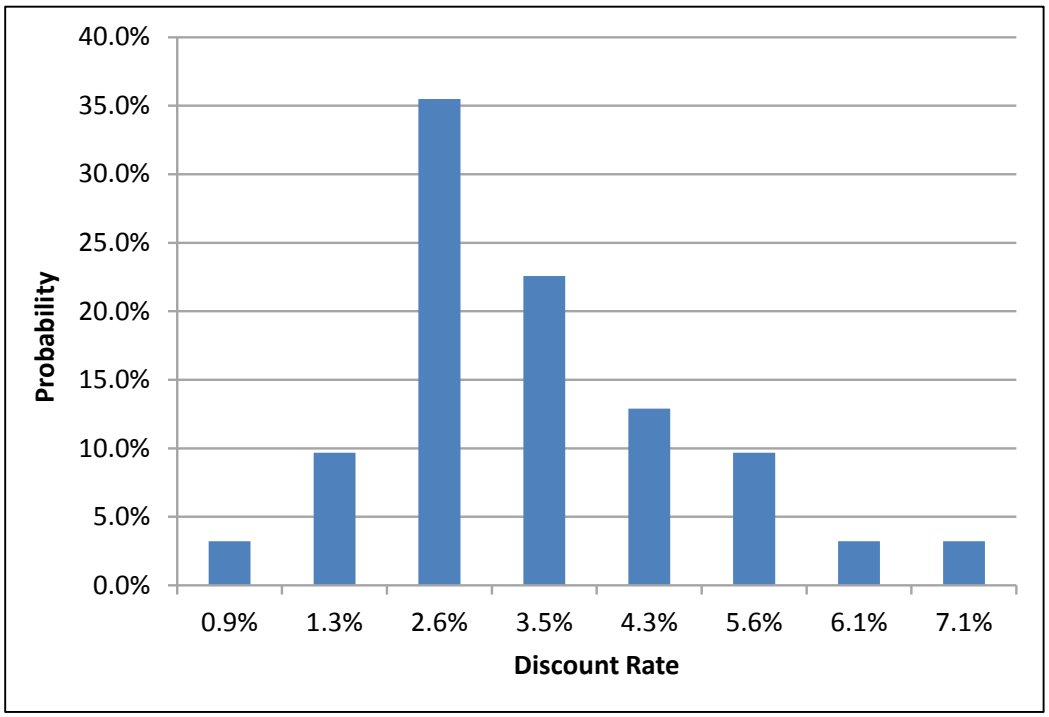

Figure 8G.3.8 Distribution of Commercial Discount Rates: Federal Government

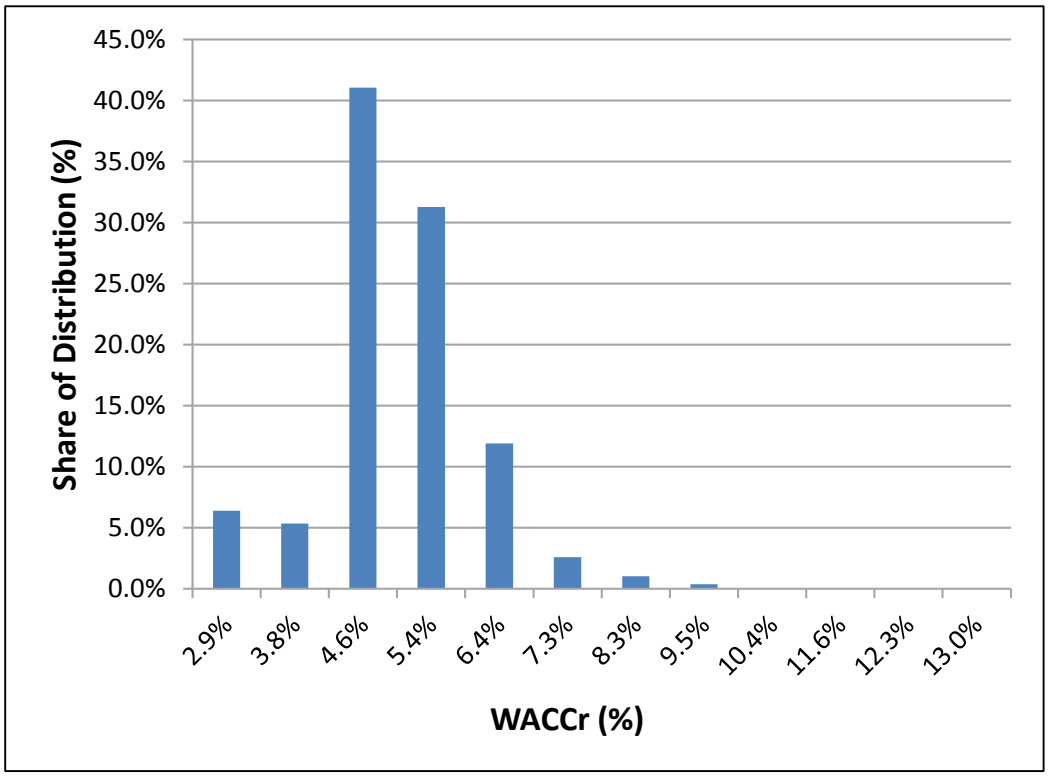

Figure 8G.3.9 Distribution of Commercial Discount Rates: Other

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APPENDIX 8H. DISTRIBUTION OF EFFICIENCY LEVELS IN THE NO-NEW-STANDARDS CASE

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APPENDIX 8H. DISTRIBUTION OF EFFICIENCY LEVELS IN THE NO-NEW-STANDARDS CASE

8H.1 INTRODUCTION

The Department of Energy (DOE) derived distributions of efficiency levels in the no-new-standards case (*i.e.*, in the absence of amended efficiency standards) by product class, which recognizes that consumers already purchasing products at efficiencies greater than or equal to a prospective standard level are not impacted by the standard. This appendix describes the distributions used.

DOE did not have access to sales data describing the actual distribution of efficiencies in current sales, nor was such information provided by industry for this rulemaking. As a consequence, DOE developed estimates of the distribution of AFUE levels for each of the four residential boiler product classes: gas-fired hot water boiler, gas-fired steam boiler, oil-fired hot water boiler, and oil-fired steam boiler. The development of these distributions was based on the following key data inputs:

- The average fraction of ENERGY STAR® shipments for gas and oil-fired boilers from 2003–2014, from ENERGY STAR data.[1]
- DOE's estimated historical residential boiler shipments by product class. See chapter 9 for further details.
- Specific efficiencies sold into the market for each product class, based on Air-Conditioning, Heating, and Refrigeration Institute (AHRI) contractor survey and Burnham's 2014 shipments data, as well as from DOE's reduced set of residential boiler models, which was derived from the AHRI Directory of Certified Product Performance and additional models for non-AHRI member manufacturers from the California Energy Commission (CEC), ENERGY STAR, and Natural Resources Canada (NRCan) boiler certification directories.[2, 3, 4, 5, 6, 7] See appendix 7D for further details.

DOE determined the standby and off mode efficiency distributions using tested from 15 boiler models and data provided by Burnham.[3]

8H.2 HISTORICAL AFUE EFFICIENCY DISTRIBUTIONS

8H.2.1 ENERGY STAR Data

The ENERGY STAR program for residential boilers started in June of 1996, and the performance criterion for ENERGY STAR boilers was set at 85-percent AFUE.[8, a] Table 8H.2.1

[a] On October 1, 2014, new ENERGY STAR criteria became effective. For gas-fired boilers, the criterion was set at 90-percent AFUE. For oil-fired boilers, the criterion was set at 87-percent AFUE.[9]

shows the market penetrations of ENERGY STAR-qualified residential boilers from 2003-2014. Some of the growth in higher efficiency boilers has been due to incentive programs (*e.g.*, Federal tax incentives, State, and utility incentives). Federal tax credits started in 2005 and remained in effect until December 31, 2014.[10]

Because there are no gas-fired steam boilers with an efficiency greater than 85-percent AFUE, DOE estimated that gas-fired steam boilers account for 0 percent of the ENERGY STAR-qualified gas-fired boilers in the period from 2003 to 2014. DOE also estimated that 94.6 percent of oil-fired boilers that qualified the ENERGY STAR performance criteria are hot water boilers, based on the fractions of oil-fired boiler models by AFUE in the DOE's reduced set of residential boiler models and the DOE's estimated historical residential boiler shipments by product class. The gas-fired and oil-fired boiler shipments that qualified for the ENERGY STAR performance criterion before October 1, 2014 were adjusted by the response rate of the ENERGY STAR partners that submitted unit shipments data. The adjusted ENERGY STAR shipments, DOE's estimated historical shipments, and the resulting disaggregated market shares of boilers by product class are summarized in Table 8H.2.1.

Table 8H.2.1 Market Penetrations of ENERGY STAR Qualified Residential Boilers

Year	Adjusted ENERGY STAR Shipments		DOE's Estimated Shipments*				DOE's Estimated Market Penetration of ENERGY STAR Shipments			
	Gas Boiler	Oil Boiler	HWGB	SGB	HWOB	SOB	HWGB	SGB	HWOB	SOB
2003	48,769	89,441	246,117	38,395	162,933	17,706	25.1%	0.0%	65.7%	34.7%
2004	96,000	115,000	271,044	37,139	180,915	19,460	39.4%	0.0%	66.8%	35.6%
2005	55,091	83,434	254,835	37,435	164,894	17,256	26.7%	0.0%	59.1%	32.4%
2006	68,102	84,668	231,573	30,504	136,518	16,016	36.3%	0.0%	72.4%	35.4%
2007	76,309	99,226	235,551	34,236	128,240	15,494	32.4%	0.0%	73.2%	34.8%
2008	109,605	75,151	257,479	40,132	100,177	12,375	44.8%	0.0%	74.7%	34.7%
2009	88,000	76,000	202,737	29,192	84,778	10,758	43.4%	0.0%	84.8%	38.3%
2010	100,000	75,000	203,742	27,237	86,690	11,132	50.1%	0.0%	83.5%	37.3%
2011	82,000	64,000	211,835	31,786	79,883	10,162	41.6%	0.0%	81.5%	36.7%
2012	109,000	57,000	243,167	35,397	65,555	8,371	45.7%	0.0%	83.9%	37.7%
2013	129,000	53,000	241,475	32,535	83,562	9,987	54.5%	0.0%	61.2%	29.4%
2014	117,000	39,000	240,454	32,054	82,475	9,793	52.9%	0.0%	48.6%	23.5%
2-year average (2013 to 2014)	123,000	46,000	240,965	32,294	83,018	9,890	53.7%	0.0%	54.9%	26.4%

* Based on the historical shipments DOE estimated for the shipments analysis. For more details see chapter 9.

8H.3 ESTIMATE OF 2015 AFUE EFFICIENCY DISTRIBUTIONS BY PRODUCT CLASS AND EFFICIENCY LEVEL

DOE developed data on the share of models in each product class by AFUE bins as shown in Table 8H.3.1 based on the latest AHRI certification directory and additional models for non-AHRI member manufacturers from CEC, ENERGY STAR, and NRCan boiler certification

directories.[11, 5, 6, 7] See appendix 7D for a full description on the development of the reduced set of models DOE used.

Table 8H.3.1 Fraction of Residential Boiler Models in 2015 by AFUE

AFUE	AFUE Bin Range	Gas-Fired Hot Water	Gas-Fired Steam	Oil-Fired Hot Water	Oil-Fired Steam
80	80-80.9		0.0%		
81	81-81.9		16.8%		
82	82-82.9	21.5%	71.6%		17.5%
83	83-83.9	7.0%	11.6%		27.5%
84	84-84.9	9.7%		26.9%	28.8%
85	85-85.9	12.1%		25.1%	18.8%
86	86-86.9	0.8%		25.7%	7.5%
87	87-87.9	0.1%		16.6%	
88	88-88.9	0.8%		2.4%	
89	89-89.9	0.1%		0.6%	
90	90-90.9	6.4%		1.6%	
91	91-91.9	3.5%		1.0%	
92	92-92.9	4.7%			
93	93-93.9	5.1%			
94	94-94.9	5.8%			
95	95-95.9	21.3%			
96	96-96.9	1.0%			
Energy Star-Qualified*		47.9%	0.0%	22.2%	0.0%

* For boilers certified after October 1, 2014.

To create the fractions of residential boilers by efficiency levels, DOE used the following criteria to process the reduced set of residential boiler models:

1. The 85% AFUE bin for gas-fired hot water boiler includes 86%-89% AFUE models.
2. The 90% AFUE bin for gas-fired hot water boilers includes 90%-91% AFUE models
3. The 92% AFUE bin for gas-fired hot water boilers includes 92%-95% AFUE models
4. The 96% AFUE bin for gas-fired hot water boilers includes 96% AFUE and above
5. The 80% AFUE bin for gas-fired steam boilers includes 80%-81% AFUE models
6. The 82% AFUE bin for gas-fired steam boilers includes 82% AFUE models
7. The 90% AFUE bin for oil-fired hot water boilers includes 90% - 91% AFUE models
8. The 82% AFUE bin for oil-fired steam boilers includes 82%-83% AFUE models
9. The 84% AFUE bin for oil-fired steam boilers includes 84% AFUE models

Table 8H.3.2 shows the adjusted fractions of residential boiler models by efficiency level in 2015 based on DOE's reduced set of boiler models.

Table 8H.3.2 Fraction of Residential Boiler Models in 2015 by Efficiency Level

EL	Design Option	Fraction of Models
Gas-fired Hot Water Boiler		
0	82% AFUE – Baseline	21.5%
1	83% AFUE – Increased HX Area	7.0%
2	84% AFUE – Increased HX Area	9.7%
3	85% AFUE – Increased HX Area	13.9%
4	90% AFUE – Condensing Baseline	10.0%
5	92% AFUE – Increased HX Area	36.9%
6	96% AFUE – Max Tech	1.0%
Gas-fired Steam Boiler		
0	80% AFUE – Baseline	16.8%
1	82% AFUE – Increased HX Area	71.6%
2	83% AFUE – Max Tech	11.6%
Oil-fired Hot Water Boiler		
0	84% AFUE – Baseline	26.9%
1	85% AFUE – Increased HX Area	25.1%
2	86% AFUE – Increased HX Area	46.9%
3	91% AFUE – Max Tech	1.0%
Oil-fired Steam Boiler		
0	82% AFUE – Baseline	45.0%
1	84% AFUE – Increased HX Area	28.8%
2	85% AFUE – Increased HX Area	18.8%
3	86% AFUE – Max Tech	7.5%

DOE then used Burnham shipments data, AHRI contractor survey data, and ENERGY STAR shipments data to further refine its estimated efficiency distribution as shown in Table 8H.3.3 to Table 8H.3.6. DOE used a combination of Burnham shipments data and AHRI contractor survey to derive fractions for non-condensing gas-fired hot water boilers and the AHRI contractor survey was used to derive fractions for non-condensing oil-fired hot water boilers. To estimate the fraction of boilers above 85% AFUE,[b] DOE used the 2-year averaged (2013-2014) market shares of residential boilers that met the ENERGY STAR performance criterion by product class (Table 8H.2.1), which result in 53.7 percent for gas-fired hot water boilers, 0 percent for gas-fired steam boilers, 54.9 percent for oil-fired hot water boilers, 26.4

[b] ENERGY STAR performance criterion before October 1, 2014, which DOE believes would still have similar market share in 2015.

percent for oil-fired steam boilers. DOE's reduced set of boiler models in 2015 (Table 8H.3.1) is then used to further disaggregated into the individual efficiency levels

Table 8H.3.3 Burnham Shipment Data in 2014 by Efficiency Level for Gas-fired Hot Water Boilers

AFUE	Total Shipments	Fraction Mechanical Draft Non-Condensing
82% AFUE	32%	2.6%
83% AFUE	26%	2.2%
84% AFUE	9%	2.3%
85% AFUE	16%	38.7%
90%+ AFUE	17%	-

Table 8H.3.4 AHRI Contractor Survey Shipment Data in 2014 by Efficiency Level for Gas-fired Boilers

AFUE Range – Draft Type	Total Shipments	Hot Water Boilers Only
82% - 83.9% - Natural Draft	18%	20%
84% - 85.0% - Natural Draft	11%	12%
82% - 88.9% - Mechanical Draft	8%	9%
89.0% - 98.0% - Mechanical Draft	50%	58%
Steam Boilers	7%	-

Table 8H.3.5 AHRI Contractor Survey Shipment Data in 2014 by Efficiency Level for Oil-fired Boilers

AFUE Range – Draft Type	Total Shipments	Hot Water Boilers Only
84% - 85.9% - Natural Draft	64%	69%
86% - 88.0% - Natural Draft	18%	20%
84% - 85.9% - Mechanical Draft	7%	7%
86% - 90% - Mechanical Draft	3%	4%
Steam Boilers	5%	-

Table 8H.3.6 Summary of Fractions Used to Derive Shipment Weighted Distribution of Residential Boiler Models in 2015 by Efficiency Level

EL	Design Option	Fraction of Models	AHRI/ Burnham Data	Energy Star Data
Gas-fired Hot Water Boiler				
0	82% AFUE – Baseline	21.5%	54.5%*	46.3%
1	83% AFUE – Increased HX Area	7.0%		
2	84% AFUE – Increased HX Area	9.7%	45.5%*	
3	85% AFUE – Increased HX Area	13.9%		53.7%
4	90% AFUE – Condensing Baseline	10.0%		
5	92% AFUE – Increased HX Area	36.9%		
6	96% AFUE – Max Tech	1.0%		
Gas-fired Steam Boiler				
0	80% AFUE – Baseline	16.8%		
1	82% AFUE – Increased HX Area	71.6%		
2	83% AFUE – Max Tech	11.6%		
Oil-fired Hot Water Boiler				
0	84% AFUE – Baseline	26.9%	76.5%**	45.1%
1	85% AFUE – Increased HX Area	25.1%		54.9%
2	86% AFUE – Increased HX Area	46.9%	23.5%**	
3	91% AFUE – Max Tech	1.0%		
Oil-fired Steam Boiler				
0	82% AFUE – Baseline	45.0%		73.6%
1	84% AFUE – Increased HX Area	28.8%		
2	85% AFUE – Increased HX Area	18.8%		26.4%
3	86% AFUE – Max Tech	7.5%		

* Combination of AHRI contractor survey and Burnham Shipments data.
** AHRI Contractor Survey data

The resulting shipment-weighted distribution of residential boiler efficiency in 2015 is summarized in Table 8H.3.7.

Table 8H.3.7 Shipment Weighted Distribution of Residential Boiler Efficiency in 2015

EL	Design Option	2015 Efficiency Distribution
Gas-fired Hot Water Boiler		
0	82% AFUE – Baseline	25.3%
1	83% AFUE – Increased HX Area	8.5%
2	84% AFUE – Increased HX Area	12.6%
3	85% AFUE – Increased HX Area	11.6%
4	90% AFUE – Condensing Baseline	8.8%
5	92% AFUE – Increased HX Area	32.4%
6	96% AFUE – Max Tech	0.9%
Gas-fired Steam Boiler		
0	80% AFUE – Baseline	16.8%
1	82% AFUE – Increased HX Area	71.6%
2	83% AFUE – Max Tech	11.6%
Oil-fired Hot Water Boiler		
0	84% AFUE – Baseline	45.1%
1	85% AFUE – Increased HX Area	18.9%
2	86% AFUE – Increased HX Area	35.3%
3	91% AFUE – Max Tech	0.8%
Oil-fired Steam Boiler		
0	82% AFUE – Baseline	44.9%
1	84% AFUE – Increased HX Area	28.7%
2	85% AFUE – Increased HX Area	18.9%
3	86% AFUE – Max Tech	7.6%

8H.4 PROJECTED AFUE MARKET SHARES FROM 2015 TO 2021 AND BEYOND

In the absence of amended AFUE standards, DOE estimated that the market shares of condensing gas-fired and condensing oil-fired hot water boilers would continue to increase from 2015 to 2050, based on historical trends in efficiency. The shares within the condensing ELs (EL 4, EL 5 and EL 6 for gas-fired hot water boilers) and the shares within the non-condensing ELs are kept in the same proportional relationship as in 2015.

8H.4.1 Condensing Boiler Market Share Trends from 2015 to 2050

ENERGY STAR implemented new performance criteria on October 1, 2014: 90-percent AFUE for gas-fired boilers (*i.e.*, condensing technology) and 87-percent AFUE for oil-fired boilers.[9]

DOE expects that adoption of ENERGY STAR's new performance criteria will gradually increase the market share of condensing boilers, but at a slower rate than in the past. There are several reasons why future growth is likely to be slower. First, incentives have been a main

driver for growth of higher efficiency boilers, and the Federal tax credits for such boilers expired at the end of 2014. Second, the remaining homes with non-condensing boilers are more likely to have difficult installations or lower energy savings from efficiency upgrades.

DOE estimated that the condensing market share of gas-fired hot water boiler in 2021 equals the market penetration of gas-fired hot water boiler that qualify the ENERGY STAR performance criteria at 2015 (53.7 percent). DOE also estimated that the condensing market share of gas-fired hot water boiler would increase 75 percent from 2021 to 2021 (from 53.7 percent in 2021 to 73.7 percent in 2050).

For oil-fired hot water boilers, DOE estimated that the condensing market share in 2021 would double from 2015 to 2021 (from 2.0 percent in 2015 to 3.9 percent in 2021) and then double again from 2021 to 2050 (from 3.9 percent in 2021 to 7.8 percent in 2050).

For both gas- and oil-fired hot water boilers, the market shares of condensing units in the years between 2015 and 2021 and between 2021 and 2050 are interpolated using the estimated market shares in 2015, 2021, and 2050. Figure 8H.4.1 and Figure 8H.4.2 plot the historical data and projections of market share of condensing gas-fired hot water boilers and condensing oil-fired hot water boilers, respectively. See appendix 7B (section 7B.2.4) for the derivation of the historical fractions of condensing gas-fired hot water boilers and condensing oil-fired hot water boilers.

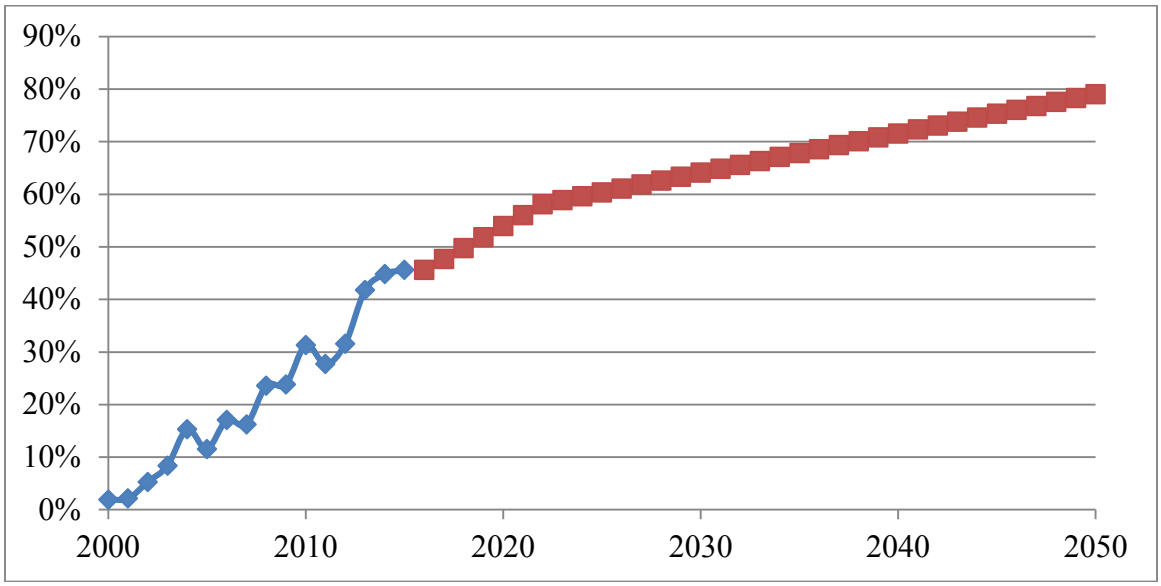

Figure 8H.4.1 Historical Data and Projection of No-New-Standards Case Market Share for Condensing Gas-fired Hot Water Residential Boilers

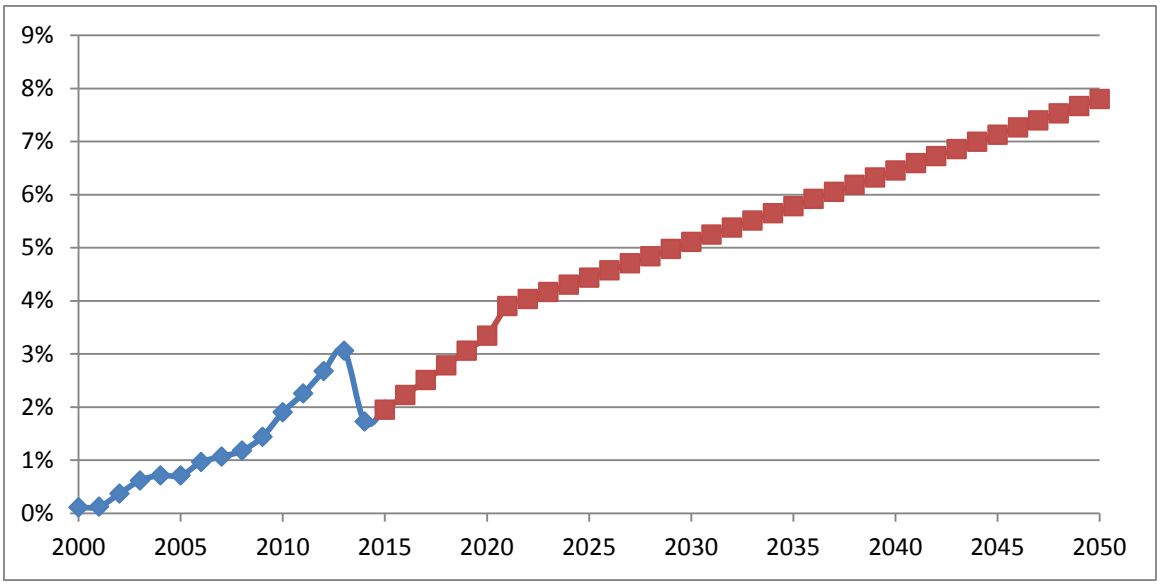

Figure 8H.4.2 Projection of No-New-Standards Case Market Share for Condensing Oil-fired Hot Water Residential Boilers

DOE estimated that the market shares of condensing gas-fired and oil-fired steam boilers will be negligible during the analysis period (2021-2050).

8H.5 ESTIMATE OF 2021 EFFICIENCY DISTRIBUTIONS BY PRODUCT CLASS

DOE used the efficiency distribution in 2015 and the projections of no-new-standards case market share of condensing boilers from 2015 to 2021 to project the efficiency distributions in 2021. The no-new-standards case efficiency distributions of condensing gas-fired and oil-fired hot water boilers in 2021 are calculated by multiplying the market shares in 2015 with a factor that considers the increase of market shares of condensing boilers from 2015 to 2021. The non-condensing gas-fired and oil-fired hot water boilers comprise the rest of the market, with their shares kept in the same proportional relationship as the market shares in 2015.[c] DOE also estimated that the no-new-standards case efficiency distributions of gas-fired and oil-fired steam boilers in 2021 are the same as in 2015. The calculated no-new-standards case efficiency distribution in 2021 is summarized in Table 8H.5.1. In addition, for gas-fired hot water boilers, DOE accounted for the regional differences in the market shares by efficiency levels (see section 8H.5.1).

[c] Note that the market share for 85% AFUE for gas-fired hot water boilers is assumed to be half that of simply applying a proportional relationship, since it is no longer the ENERGY STAR level (decreasing from 9.2% to 4.6%). The remaining half is divided proportional between 82-84% AFUE efficiency levels.

Table 8H.5.1 No-New-Standards Case Distribution of Residential Boiler Efficiency in 2021

EL	Design Option	2021 Efficiency Distribution
Gas-fired Hot Water Boiler		
0	82% AFUE – Baseline	22.8%
1	83% AFUE – Increased HX Area	7.6%
2	84% AFUE – Increased HX Area	11.3%
3	85% AFUE – Increased HX Area	4.6%
4	90% AFUE – Condensing Baseline	11.2%
5	92% AFUE – Increased HX Area	41.3%
6	96% AFUE – Max Tech	1.2%
Gas-fired Steam Boiler		
0	80% AFUE – Baseline	16.8%
1	82% AFUE – Increased HX Area	71.6%
2	83% AFUE – Max Tech	11.6%
Oil-fired Hot Water Boiler		
0	84% AFUE – Baseline	44.2%
1	85% AFUE – Increased HX Area	18.5%
2	86% AFUE – Increased HX Area	33.4%
3	91% AFUE – Max Tech	3.9%
Oil-fired Steam Boiler		
0	82% AFUE – Baseline	44.9%
1	84% AFUE – Increased HX Area	28.7%
2	85% AFUE – Increased HX Area	18.9%
3	86% AFUE – Max Tech	7.6%

8H.5.1 Gas-fired Hot Water Boiler Condensing Fraction by Region

Based on state-level shipments data provided by AHRI of cast-iron and condensing gas-fired hot water boilers from 2008-2012, the fraction of condensing gas-fired hot water boiler shipments by state varies significantly.[12] DOE used this data to estimate the fraction of condensing boiler shipments to each census division in 2021 by using the following equation:

$$Fraction\ of\ Condensing\ Gas\text{-}fired\ Boilers\ by\ Census\ Division = CondFrac_{census\ division,AHRI} \times \frac{CondFrac_{national,DOE\ in\ 2021}}{CondFrac_{national,AHRI}}$$

Eq. 8H.1

Where:

$CondFrac_{census\ division,AHRI}$ = average fraction of condensing gas-fired hot water boiler shipments by census division based on AHRI data from 2008-2012 as listed in Table 8H.5.3,

$CondFrac_{national,DOE\ in\ 2021}$ = DOE's projected national fraction of condensing gas-fired hot water boiler shipments as listed in section 8H.4.1 (45.8 percent), and

$CondFrac_{national,AHRI}$ = average national fraction of condensing gas-fired hot water boiler shipments based on AHRI data from 2008-2012 as listed in Table 8H.5.3 (28.6 percent).

The estimated fractions of condensing hot water gas-fired boiler shipments by RECS 2009 regions and by CBECS 2003 census division in 2021 are summarized in Table 8H.5.2 and Table 8H.5.3.

Table 8H.5.2 Fraction of Condensing Gas-fired Hot Water Boiler Shipments in 2021 by RECS 2009 Regions

ID	RECS 2009 Regions	Fraction of Condensing Gas-fired Hot Water Boiler Shipments (2008-2012)	Projected 2021 Fraction of Condensing Gas-fired Hot Water Boiler Shipments
1	CT, ME, NH, RI, VT	41.9%	70.4%
2	Massachusetts	40.6%	68.8%
3	New York	14.2%	35.5%
4	New Jersey	11.8%	32.5%
5	Pennsylvania	20.8%	43.8%
6	Illinois	19.8%	42.5%
7	Indiana, Ohio	32.7%	58.8%
8	Michigan	40.4%	68.5%
9	Wisconsin	58.6%	91.5%
10	IA, MN, ND, SD	44.5%	73.7%
11	Kansas, Nebraska	38.8%	66.6%
12	Missouri	46.1%	75.7%
13	Virginia	27.4%	52.1%
14	DE, DC, MD	26.7%	51.3%
15	Georgia	28.0%	52.9%
16	NC, SC	46.8%	76.6%
17	Florida	36.4%	63.5%
18	AL, KY, MS	62.1%	100.0%
19	Tennessee	16.7%	38.6%
20	AR, LA, OK	82.8%	100.0%
21	Texas	17.3%	39.4%
22	Colorado	61.1%	100.0%
23	ID, MT, UT, WY	66.7%	100.0%
24	Arizona	93.7%	100.0%
25	NV, NM	46.1%	75.7%
26	California	87.4%	100.0%
27	OR, WA	59.0%	92.1%
28	Alaska	51.0%	82.0%
29	Hawaii	50.0%	80.7%
30	West Virginia	55.6%	87.7%
	United States	28.6%	53.7%

Table 8H.5.3 Fraction of Condensing Gas-fired Hot Water Boiler Shipments in 2021 by CBECS 2003 Census Divisions

ID	Census Division	Fraction of Condensing Gas-fired Hot Water Boiler Shipments (2008-2012)	Projected 2021 Fraction of Condensing Gas-fired Hot Water Boiler Shipments
1	New England	41.3%	69.6%
2	Middle Atlantic	15.0%	36.5%
3	East North Central	36.1%	63.1%
4	West North Central	44.4%	73.7%
5	South Atlantic	27.7%	52.5%
6	East South Central	38.2%	65.8%
7	West South Central	56.2%	88.5%
8	Mountain	61.5%	100.0%
9	Pacific	64.0%	100.0%
	United States	28.6%	53.7%

8H.6 STANDBY AND OFF-MODE EFFICIENCY DISTRIBUTIONS

To determine the standby and off-mode efficiency distributions, DOE tested 15 boiler models and used the data Burnham provided for an additional 6 models (see Table 8H.6.1).[3] DOE determined that the only two out of the 21 models (or about 10 percent) were above max tech efficiency level (EL 3) Furthermore, the units with higher standby power tend to be higher efficiency units. Based on this, for the boiler standby mode and off mode standards, DOE estimated for higher efficiency hot water gas boilers (90% AFUE and above) and hot water oil boilers (86% AFUE and above) that 5 percent of shipments would be at the baseline standby and off mode efficiency level (EL 0), 5 percent of shipments would be at EL 1, 5 percent of shipments would be at EL 2, and 85 percent would be at the standby and off mode max-tech efficiency level (EL 3). For all other boilers, DOE estimated that 1 percent of shipments would be at the baseline standby and off mode efficiency level (EL 0), 1 percent of shipments would be at EL 1, 1 percent of shipments would be at EL 2, and 97 percent would be at the standby and off model max-tech efficiency level (EL 3).

Table 8H.6.1 Standby Power and Off-Mode Power Test Data

Manufacturer	Model	AFUE Range	Standby and Off-Mode Power (W)
Hot Water Gas-fired Boiler			
Mfr A	Model 1	82-85%	2.86
Mfr A	Model 2	82-85%	3.28
Mfr B	Model 1	82-85%	3.68
Mfr B	Model 2	82-85%	4.02
Mfr C	Model 1	82-85%	4.19
Mfr C	Model 2	82-85%	4.22
Mfr D	Model 1	90-96%	5.35
Burnham	Atmospheric	82-85%	7.19
Burnham	Fan Assisted	82-85%	7.42
Mfr E	Model 1	90-96%	7.84
Mfr D	Model 2	90-96%	7.99
Mfr E	Model 2	90-96%	8.04
Mfr B	Model 3	90-96%	8.04
Burnham	Condensing, Modulating	90-96%	8.34
Mfr B	Model 4	90-96%	8.62
Mfr B	Model 5	90-96%	9.76
Steam Gas-fired Boiler			
Mfr F	Model 1	80-84%	4.44
Mfr B	Model 6	80-84%	5.00
Burnham	Atmospheric	80-84%	11.16
Hot Water Oil-fired Boiler			
Burnham		unknown	7.42
Steam Oil-fired Boiler			
Burnham		unknown	7.69

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APPENDIX 8I. LIFE-CYCLE COST ANALYSIS USING ALTERNATIVE ECONOMIC GROWTH SCENARIOS FOR RESIDENTIAL BOILERS

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APPENDIX 8I. LIFE-CYCLE COST ANALYSIS USING ALTERNATIVE ECONOMIC GROWTH SCENARIOS FOR RESIDENTIAL BOILERS

8I.1 INTRODUCTION

This appendix presents life-cycle cost (LCC) results using energy price projections from alternative economic growth scenarios. The scenarios are based on the High Economic Growth case and the Low Economic Growth case from Energy Information Administration (EIA)'s *Annual Energy Outlook 2015* (*AEO 2015*).[1]

This appendix describes the High and Low Economic Growth scenarios in further detail. See appendix 8-A for details about how to generate LCC results for High Economic Growth and Low Economic Growth scenarios using the LCC spreadsheet.

8I.2 DESCRIPTION OF HIGH AND LOW ECONOMIC SCENARIOS

To generate LCC results reported in chapter 8, DOE uses the Reference case energy price projections from *AEO 2015*. The reference case is a business-as-usual estimate, given known market, demographic, and technological trends. For *AEO 2015*, EIA explored the impacts of alternative assumptions in other scenarios with different macroeconomic growth rates, world oil prices, rates of technology progress, and policy changes.

To reflect uncertainty in the projection of U.S. economic growth, EIA's *AEO 2015* uses High and Low Economic Growth scenarios to project the possible impacts of alternative economic growth assumptions on energy markets. The High Economic Growth scenario incorporates population, labor force and productivity growth rates that are higher than the Reference scenario, while these values are lower for the Low Economic Growth scenario. Economic output as measured by real GDP increases by 2.4 percent per year from 2013 through 2040, in the Reference case, 1.8 percent per year in the Low Economic Growth case, and 2.9 percent per year in the High Economic Growth case.[2]

Energy prices are higher in the High Economic Growth scenario and lower in the Low Economic Growth scenario. The energy price forecasts affect the operating cost savings at different efficiency levels. Figure 8I.2.1 through Figure 8I.2.4 show the national price trends for the Reference, High Economic Growth, and Low Economic Growth scenarios to illustrate the general price trends. To estimate energy prices after 2040 in the high and low scenarios, DOE used the growth rate between 2025 and 2040. In these figures, price trends after 2040 are presented with a dashed line because they are not part of *AEO 2015* projections.

Because *AEO 2015* provides the price trends by census division, each sampled household is matched to the appropriate census division price trend. See appendix 8D for details about how energy price trends by census division are applied in the LCC analysis.

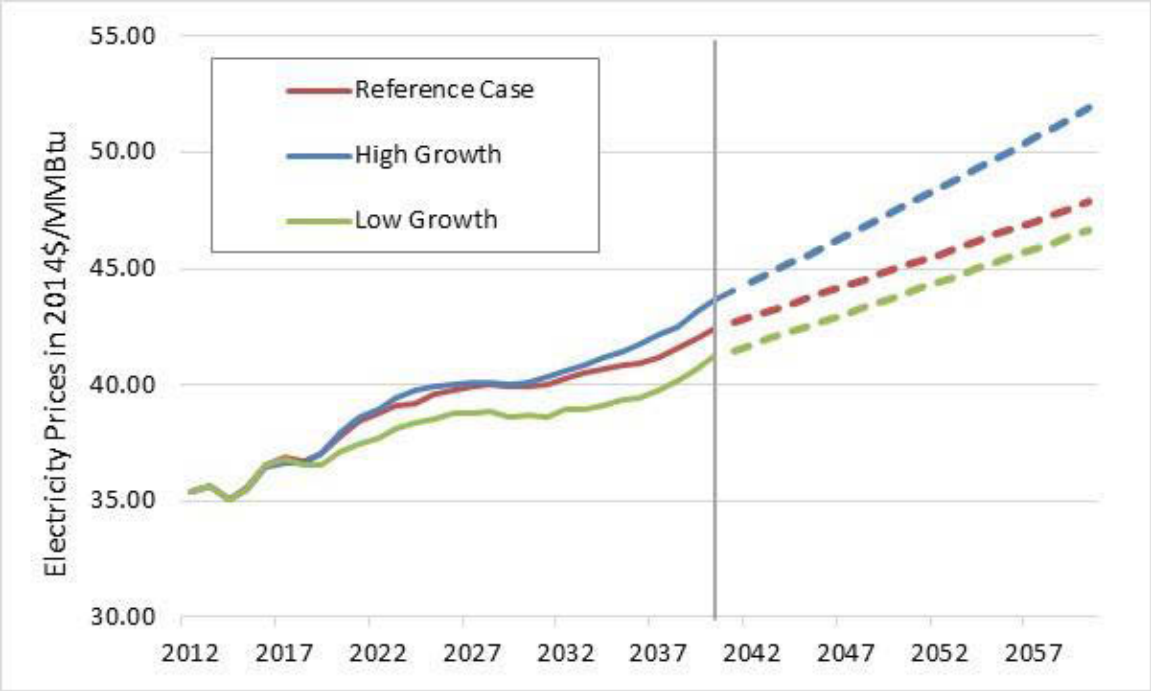

Figure 8I.2.1 Electricity Price Forecasts for Reference Case and High and Low Economic Growth Scenarios (National)

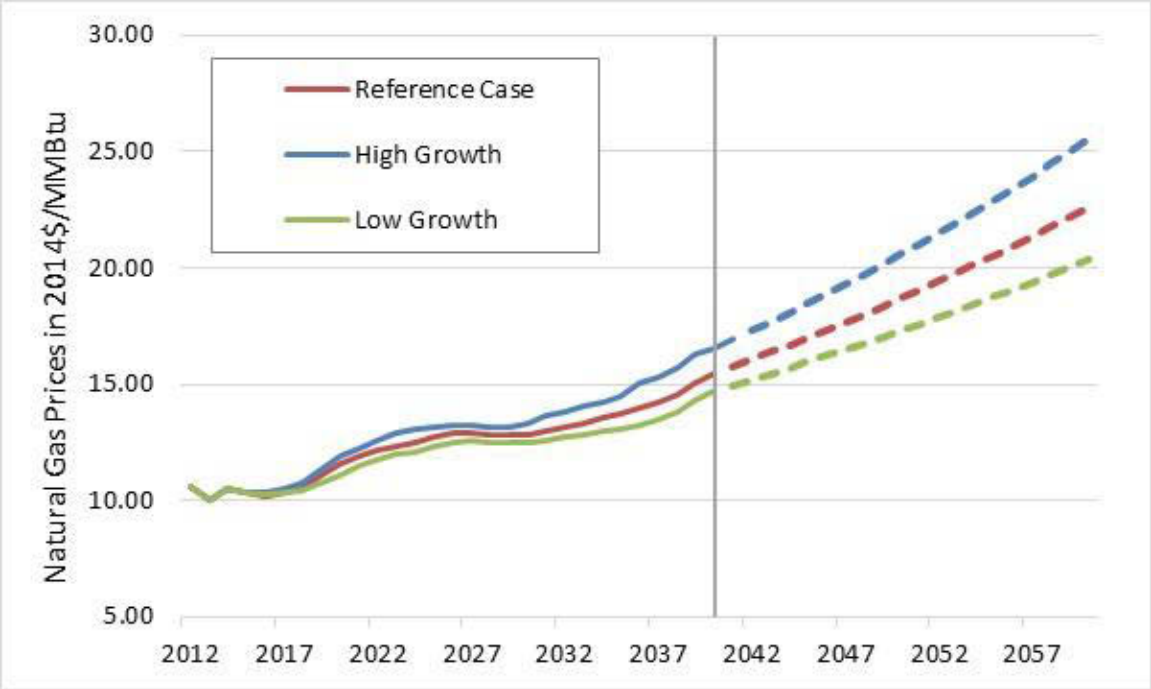

Figure 8I.2.2 Natural Gas Price Forecasts for Reference Case and High and Low Economic Growth Scenarios (National)

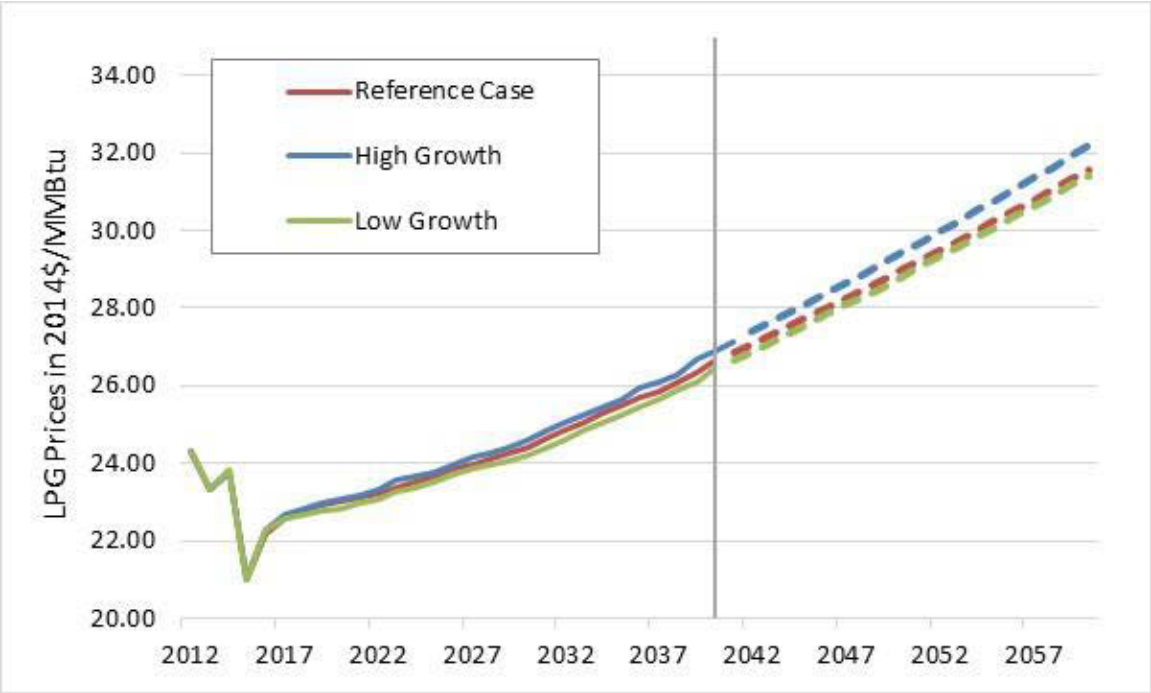

Figure 8I.2.3 LPG Price Forecasts for Reference Case and High and Low Economic Growth Scenarios (National)

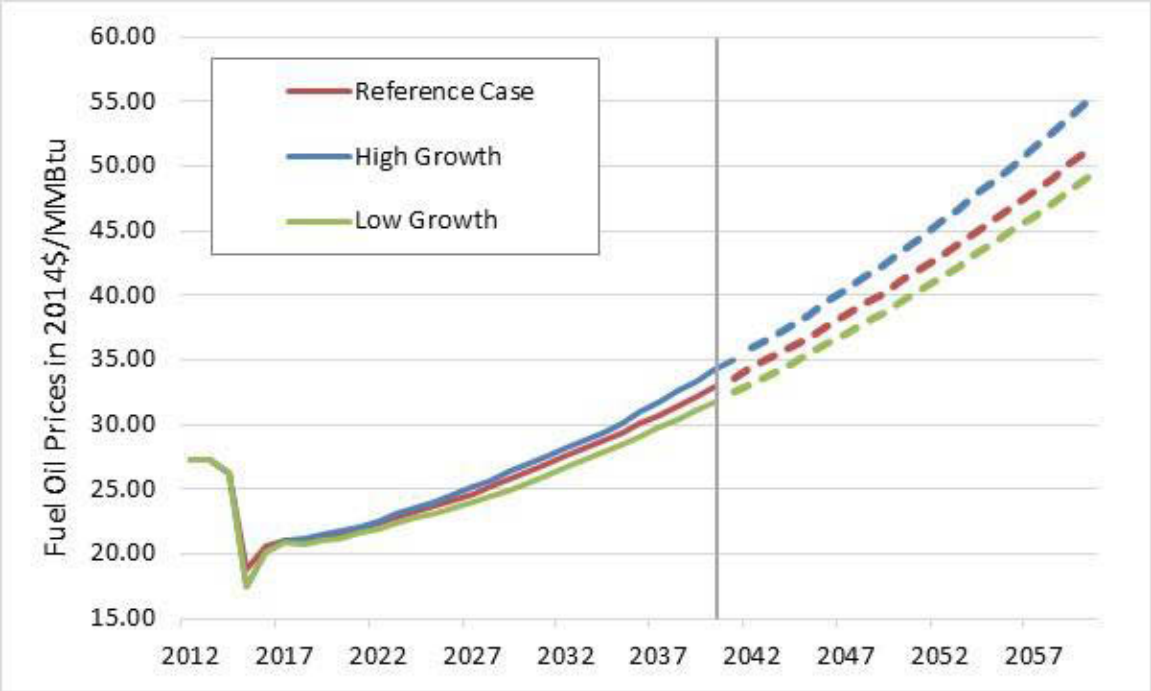

Figure 8I.2.4 Fuel Oil Price Forecasts for Reference Case and High and Low Economic Growth Scenarios (National)

8I.3 RESULTS

8I.3.1 AFUE Standards

Table 8I.3.1 through Table 8I.3.4 summarize the LCC and PBP results for High-Economic Growth and Low Economic Growth scenarios for AFUE standards. In the first of each pair of tables, the simple payback is measured relative to the baseline equipment. In the second of each pair of tables, the impacts are measured relative to the efficiency distribution in the no-new-standards case in the compliance year (2021). Table 8I.3.5 compares average LCC savings and simple payback for these scenarios to the Reference case for AFUE standards. The High-Economic Growth LCC savings are slightly higher and PBP are slightly shorter than the Reference case. The Low Economic Growth LCC savings are slightly lower and PBP are slightly longer than the Reference case.

Table 8I.3.1 Average LCC and PBP Results for High Economic Growth Scenario for AFUE Standards

Product Class	EL	Average Costs (2014$)				Simple Payback *years*	Average Lifetime *years*
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
Gas-Fired Hot Water Boilers	0	$6,371	$1,264	$23,714	$30,085	NA	26.6
	1	$6,387	$1,250	$23,464	$29,851	1.2	26.6
	2	$6,402	$1,237	$23,221	$29,623	1.2	26.6
	3	$6,649	$1,225	$22,997	$29,646	7.2	26.6
	4	$7,255	$1,155	$21,664	$28,919	8.1	26.6
	5	$7,605	$1,134	$21,278	$28,884	9.5	26.6
	6	$8,295	$1,095	$20,554	$28,849	11.4	26.6
Gas-Fired Steam Boilers	0	$6,313	$1,125	$19,055	$25,367	NA	23.6
	1	$6,376	$1,101	$18,645	$25,021	2.6	23.6
	2	$6,682	$1,089	$18,451	$25,133	10.3	23.6
Oil-Fired Hot Water Boilers	0	$8,049	$2,037	$40,006	$48,055	NA	24.7
	1	$8,200	$2,015	$39,565	$47,766	6.8	24.7
	2	$8,351	$1,984	$38,957	$47,309	5.7	24.7
	3	$10,691	$1,875	$36,775	$47,467	16.4	24.7
Oil-Fired Steam Boilers	0	$7,886	$1,988	$30,924	$38,810	NA	19.3
	1	$8,189	$1,942	$30,203	$38,392	6.6	19.3
	2	$8,341	$1,920	$29,856	$38,197	6.7	19.3
	3	$8,644	$1,890	$29,386	$38,031	7.7	19.3

Note: The results for each TSL are calculated assuming that all consumers use products at that efficiency level. The PBP is measured relative to the baseline equipment.

Table 8I.3.2 LCC Savings Relative to the No-New-Standards Case Efficiency Distribution for High Economic Growth Scenario for AFUE Standards

Product Class	EL	% of Consumers that Experience Net Cost	Average LCC Savings* *2014$*
Gas-Fired Hot Water Boilers	0	0%	NA
	1	0%	$220
	2	0%	$382
	3	13%	$207
	4	21%	$720
	5	28%	$601
	6	54%	$386
Gas-Fired Steam Boilers	0	0%	NA
	1	1%	$353
	2	29%	$235
Oil-Fired Hot Water Boilers	0	0%	NA
	1	10%	$272
	2	9%	$651
	3	58%	$272
Oil-Fired Steam Boilers	0	0%	NA
	1	12%	$416
	2	19%	$452
	3	33%	$530

* The savings represent the average LCC for affected consumers

Table 8I.3.3 Average LCC and PBP Results for Low Economic Growth Scenario for AFUE Standards

Product Class	EL	Average Costs (2014$)				Simple Payback *years*	Average Lifetime *years*
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
Gas-Fired Hot Water Boilers	0	$6,387	$1,176	$21,678	$28,065	NA	26.6
	1	$6,402	$1,163	$21,454	$27,856	1.2	26.6
	2	$6,649	$1,152	$21,251	$27,900	1.3	26.6
	3	$7,255	$1,086	$20,041	$27,296	7.7	26.6
	4	$7,605	$1,067	$19,686	$27,292	8.7	26.6
	5	$8,295	$1,030	$19,019	$27,315	10.1	26.6
	6	$6,387	$1,176	$21,678	$28,065	12.2	26.6
Gas-Fired Steam Boilers	0	$6,313	$1,054	$17,641	$23,954	NA	23.6
	1	$6,376	$1,031	$17,264	$23,641	2.8	23.6
	2	$6,682	$1,020	$17,086	$23,768	11.0	23.6
Oil-Fired Hot Water Boilers	0	$8,049	$1,990	$37,893	$45,942	NA	24.7
	1	$8,200	$1,968	$37,477	$45,678	7.0	24.7
	2	$8,351	$1,938	$36,903	$45,255	5.9	24.7
	3	$10,691	$1,832	$34,849	$45,541	16.8	24.7
Oil-Fired Steam Boilers	0	$7,886	$1,943	$29,468	$37,353	NA	19.3
	1	$8,189	$1,898	$28,783	$36,972	6.7	19.3
	2	$8,341	$1,876	$28,453	$36,794	6.8	19.3
	3	$8,644	$1,847	$28,006	$36,651	7.9	19.3

Note: The results for each TSL are calculated assuming that all consumers use products at that efficiency level. The PBP is measured relative to the baseline equipment.

Table 8I.3.4 LCC Savings Relative to the No-New-Standards Case Efficiency Distribution for Low Economic Growth Scenario for AFUE Standards

Product Class	EL	% of Consumers that Experience Net Cost	Average LCC Savings* *2014$*
Gas-Fired Hot Water Boilers	0	0%	NA
	1	0%	$201
	2	0%	$348
	3	13%	$163
	4	22%	$563
	5	30%	$444
	6	57%	$237
Gas-Fired Steam Boilers	0	0%	NA
	1	1%	$319
	2	32%	$186
Oil-Fired Hot Water Boilers	0	0%	NA
	1	11%	$247
	2	9%	$600
	3	60%	$109
Oil-Fired Steam Boilers	0	0%	NA
	1	12%	$380
	2	20%	$413
	3	35%	$475

* The savings represent the average LCC for affected consumers

Table 8I.3.5 Comparison of Average LCC Savings, Percent of Consumers that Experience Net Cost, and Simple Payback Period Results for Reference Case and High and Low Economic Growth Scenarios for AFUE Standards

Product Class	EL	Average LCC Savings *2014$*			% of Consumers that Experience Net Cost *%*			Simple Payback Period *Years*		
		High Growth	Low Growth	Ref Case	High Growth	Low Growth	Ref Case	High Growth	Low Growth	Ref Case
Gas-fired Hot Water Boiler	1	$220	$201	$210	0%	0%	0%	1.2	1.2	1.2
	2	$382	$348	$364	0%	0%	0%	1.2	1.3	1.2
	3	$207	$163	$182	13%	13%	13%	7.2	7.7	7.5
	4	$720	$563	$632	21%	22%	22%	8.1	8.7	8.4
	5	$601	$444	$513	28%	30%	29%	9.5	10.1	9.9
	6	$386	$237	$303	54%	57%	55%	11.4	12.2	11.8
Gas-fired Steam Boiler	1	$353	$319	$333	1%	1%	1%	2.6	2.8	2.7
	2	$235	$186	$207	29%	32%	31%	10.3	11.0	10.7
Oil-fired Hot Water Boiler	1	$272	$247	$260	10%	11%	10%	6.8	7.0	6.9
	2	$651	$600	$626	9%	9%	9%	5.7	5.9	5.8
	3	$272	$109	$192	58%	60%	59%	16.4	16.8	16.5
Oil-fired Steam Boiler	1	$416	$380	$400	12%	12%	12%	6.6	6.7	6.6
	2	$452	$413	$434	19%	20%	20%	6.7	6.8	6.7
	3	$530	$475	$505	33%	35%	34%	7.7	7.9	7.8

8I.3.2 Standby Mode and Off Mode Standards

Table 8I.3.6 through Table 8I.3.9 summarize the LCC and PBP results for High-Economic Growth and Low Economic Growth scenarios for standby mode and off mode standards. In the first of each pair of tables, the simple payback is measured relative to the baseline equipment. In the second of each pair of tables, the impacts are measured relative to the efficiency distribution in the no-new-standards case in the compliance year (2021). Table 8I.3.10 compares average LCC savings and simple payback for these scenarios to the Reference case for standby mode and off mode standards. The LCC savings and PBPs for both economic scenarios are very similar to the Reference case. The High Economic Growth LCC savings are slightly higher and PBP are slightly shorter than the Reference case. The Low Economic Growth LCC savings are slightly lower and PBP are slightly longer than the Reference case.

Table 8I.3.6 LCC and PBP Results for High Economic Growth Scenario for Standby Mode and Off Mode Standards

Product Class	EL	Average Costs (2014$)				Simple Payback *years*	Average Lifetime *years*
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
Gas-Fired Hot Water Boilers	0	$28	$15	$264	$293	NA	26.6
	1	$32	$13	$229	$261	2.0	26.6
	2	$49	$12	$222	$271	8.8	26.6
	3	$50	$11	$205	$255	6.6	26.6
Gas-Fired Steam Boilers	0	$28	$14	$231	$259	NA	23.6
	1	$31	$12	$197	$229	1.9	23.6
	2	$48	$12	$191	$239	8.4	23.6
	3	$49	$11	$175	$224	6.3	23.6
Oil-Fired Hot Water Boilers	0	$28	$19	$322	$349	NA	24.7
	1	$31	$17	$286	$317	1.8	24.7
	2	$48	$16	$278	$326	8.1	24.7
	3	$49	$15	$262	$311	6.1	24.7
Oil-Fired Steam Boilers	0	$28	$19	$269	$297	NA	19.3
	1	$31	$17	$239	$270	1.8	19.3
	2	$48	$16	$233	$281	7.9	19.3
	3	$49	$15	$219	$268	6.0	19.3
Electric Hot Water Boilers	0	$27	$10	$175	$202	NA	26.6
	1	$31	$8	$149	$180	2.6	26.6
	2	$47	$8	$144	$192	11.6	26.6
	3	$48	$8	$133	$181	8.8	26.6
Electric Steam Boilers	0	$27	$10	$159	$186	NA	23.6
	1	$31	$9	$136	$167	2.6	23.6
	2	$47	$8	$132	$179	11.6	23.6
	3	$48	$8	$121	$169	8.8	23.6

Note: The results for each TSL are calculated assuming that all consumers use products at that efficiency level. The PBP is measured relative to the baseline equipment.

Table 8I.3.7 LCC Savings Relative to the No-New-Standards Case Efficiency Distribution for High Economic Growth Scenario for Standby Mode and Off Mode Standards

Product Class	EL	% of Consumers that Experience Net Cost	Average LCC Savings* *2014$*
Gas-Fired Hot Water Boilers	0	0%	NA
	1	0%	$27
	2	4%	$3
	3	2%	$16
Gas-Fired Steam Boilers	0	0%	NA
	1	0%	$32
	2	1%	$4
	3	1%	$18
Oil-Fired Hot Water Boilers	0	0%	NA
	1	0%	$33
	2	3%	$6
	3	1%	$20
Oil-Fired Steam Boilers	0	0%	NA
	1	0%	$26
	2	1%	$1
	3	1%	$13
Electric Hot Water Boilers	0	0%	NA
	1	0%	$20
	2	2%	-$3
	3	1%	$9
Electric Steam Boilers	0	0%	NA
	1	0%	$18
	2	2%	-$4
	3	1%	$7

* The savings represent the average LCC for affected consumers

Table 8I.3.8 Average LCC and PBP Results for Low Economic Growth Scenario for Standby Mode and Off Mode Standards

Product Class	EL	Average Costs (2014$)				Simple Payback *years*	Average Lifetime *years*
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
Gas-Fired Hot Water Boilers	0	$28	$14	$254	$282	NA	26.6
	1	$32	$12	$220	$252	2.1	26.6
	2	$49	$12	$213	$262	9.3	26.6
	3	$50	$11	$197	$247	7.0	26.6
Gas-Fired Steam Boilers	0	$28	$13	$222	$249	NA	23.6
	1	$31	$11	$190	$221	2.0	23.6
	2	$48	$11	$183	$231	8.9	23.6
	3	$49	$10	$168	$217	6.7	23.6
Oil-Fired Hot Water Boilers	0	$28	$18	$309	$337	NA	24.7
	1	$31	$16	$275	$306	1.9	24.7
	2	$48	$15	$268	$316	8.6	24.7
	3	$49	$14	$252	$301	6.5	24.7
Oil-Fired Steam Boilers	0	$28	$18	$260	$287	NA	19.3
	1	$31	$16	$230	$262	1.9	19.3
	2	$48	$15	$225	$272	8.4	19.3
	3	$49	$15	$211	$260	6.4	19.3
Electric Hot Water Boilers	0	$27	$9	$164	$191	NA	26.6
	1	$31	$8	$140	$171	2.7	26.6
	2	$47	$8	$135	$183	12.2	26.6
	3	$48	$7	$124	$173	9.2	26.6
Electric Steam Boilers	0	$27	$10	$150	$177	NA	23.6
	1	$31	$8	$128	$159	2.7	23.6
	2	$47	$8	$124	$171	12.2	23.6
	3	$48	$7	$114	$162	9.2	23.6

Note: The results for each TSL are calculated assuming that all consumers use products at that efficiency level. The PBP is measured relative to the baseline equipment.

Table 8I.3.9 LCC Savings Relative to the No-New-Standards Case Efficiency Distribution for Low Economic Growth Scenario for Standby Mode and Off Mode Standards

Product Class	EL	% of Consumers that Experience Net Cost	Average LCC Savings* *2014$*
Gas-Fired Hot Water Boilers	0	0%	NA
	1	0%	$25
	2	4%	$2
	3	2%	$14
Gas-Fired Steam Boilers	0	0%	NA
	1	0%	$30
	2	1%	$3
	3	1%	$17
Oil-Fired Hot Water Boilers	0	0%	NA
	1	0%	$31
	2	4%	$5
	3	2%	$19
Oil-Fired Steam Boilers	0	0%	NA
	1	0%	$25
	2	1%	$0
	3	1%	$12
Electric Hot Water Boilers	0	0%	NA
	1	0%	$19
	2	2%	-$4
	3	1%	$7
Electric Steam Boilers	0	0%	NA
	1	0%	$17
	2	2%	-$5
	3	1%	$5

* The savings represent the average LCC for affected consumers

Table 8I.3.10 Comparison of Average LCC Savings, Percent of Consumers that Experience Net Cost, and Simple Payback Period Results for Reference Case and High and Low Economic Growth Scenarios for Standby Mode and Off Mode Standards

Product Class	EL	Average LCC Savings *2014$*			% of Consumers that Experience Net Cost *%*			Simple Payback Period *Years*		
		High Growth	Low Growth	Ref Case	High Growth	Low Growth	Ref Case	High Growth	Low Growth	Ref Case
Gas-fired Hot Water Boiler	1	$27	$25	$26	0%	0%	0%	2.0	2.1	2.0
	2	$3	$2	$2	4%	4%	4%	8.8	9.3	8.9
	3	$16	$14	$15	2%	2%	2%	6.6	7.0	6.7
Gas-fired Steam Boiler	1	$32	$30	$31	0%	0%	0%	1.9	2.0	1.9
	2	$4	$3	$4	1%	1%	1%	8.4	8.9	8.5
	3	$18	$17	$18	1%	1%	1%	6.3	6.7	6.4
Oil-fired Hot Water Boiler	1	$33	$31	$32	0%	0%	0%	1.8	1.9	1.8
	2	$6	$5	$6	3%	4%	3%	8.1	8.6	8.2
	3	$20	$19	$20	1%	2%	1%	6.1	6.5	6.2
Oil-fired Steam Boiler	1	$26	$25	$26	0%	0%	0%	1.8	1.9	1.8
	2	$1	$0	$0	1%	1%	1%	7.9	8.4	8.0
	3	$13	$12	$13	1%	1%	1%	6.0	6.4	6.1
Electric Hot Water Boiler	1	$20	$19	$19	0%	0%	0%	2.6	2.7	2.6
	2	-$3	-$4	-$3	2%	2%	2%	11.6	12.2	11.7
	3	$9	$7	$8	1%	1%	1%	8.8	9.2	8.9
Electric Steam Boiler	1	$18	$17	$17	0%	0%	0%	2.6	2.7	2.6
	2	-$4	-$5	-$5	2%	2%	2%	11.6	12.2	11.7
	3	$7	$5	$6	1%	1%	1%	8.8	9.2	8.8

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CHAPTER 9. SHIPMENTS ANALYSIS

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CHAPTER 9. SHIPMENTS ANALYSIS

9.1 INTRODUCTION

Estimates of future product shipments are a necessary input to calculations of the national energy savings (NES) and net present value (NPV), as well as to the manufacturer impact analysis (MIA). This chapter describes the data and methods the U.S. Department of Energy (DOE) used to project annual product shipments and presents results for residential boiler product classes considered in this analysis.

The shipments model divides the shipments of residential boilers into specific market segments. The model starts from a historical base year and calculates retirements and shipments by market segment for each year of the analysis period. This approach produces an estimate of the total product stock, broken down by age or vintage, in each year of the analysis period. In addition, the product stock efficiency distribution is calculated for the no-new-standards case (*i.e.*, without new or amended standards) and for each standards case for each product class. The stock distribution is used in the national impact analysis (NIA) to estimate the total costs and benefits associated with each efficiency level.

The shipments model was developed as a Microsoft Excel spreadsheet that is accessible on DOE's Appliance and Commercial Equipment Standards website (www1.eere.energy.gov/buildings/appliance_standards/rulemaking.aspx?ruleid=112). Appendix 10A discusses how to access and utilize the shipments model spreadsheet, which is integrated into the spreadsheet for the NIA. This chapter explains how the shipments model is constructed and provides summary shipments results (section 9.5). Sections 9.2.1 through 9.4 describe the methodological approach.

9.2 SHIPMENTS MODEL METHODOLOGY

The shipments model disaggregates the total stock according to the following characteristics:

1. Product class: Six residential boiler product classes were considered in this analysis: gas-fired hot water boilers, gas-fired steam boilers, oil-fired hot water boilers, oil-fired steam boilers, electric hot water boilers, and electric steam boilers.[a]

2. Application market sector: Residential and commercial building sectors.

The residential boiler shipments model considers three product market segments (hereafter referred to as "market segments") as follows:

[a] Electric hot water boilers and electric steam boilers were only considered for standby mode and off mode standards.

1. New construction: a certain fraction of new buildings acquire boilers in each future year. This fraction is defined as the new construction saturation, which varies by year, and by product class.

2. Existing owners (replacements): these are defined as existing buildings with boilers installed. This category receives new shipments when existing products are replaced.

3. New owners: these are defined as existing buildings that acquire boilers for the first time during the analysis period. The new owners primarily consist of households that during a major remodel add or switch to hydronic heating. For this analysis, new owners also include households switching between different boiler product classes.

9.2.1 Fundamental Model Equations

The fundamental dependent variable in the shipments model is the product stock, which is represented as a function of analysis year (indexed by *j*), and product vintage or age (the product age is noted as *a,* and is equal to the analysis year minus the vintage). The stock function is adjusted in each year of the analysis period by new shipments coming in and broken or demolished products being taken out.

For existing stock:

$$Stock_p(j,a) = Stock_p(j-1,a-1) - Rem_p(j,a) + Ship_p(j-1)$$

Eq. 9.1

and for new shipments:

$$Stock_p(j,a=1) = Ship_p(j-1)$$

Eq. 9.2

Where:

$Stock_p$ (j, a) = number of units of product class p and age a in analysis year j,
Rem_p (j, a) = number of units of product class p and age a removed in analysis year j, and
$Ship_p(j)$ = number of units of product class p shipped in year j.

Removals due to product failure contain a survival function $f_p(a)$ that is used to represent the probability that a unit of age a will survive in a given year; equivalently, the probability that this unit will fail is $1-f_p(a)$.

Total removals in the no-new-standards case are then:

$$Rem_p(j,a) = [1 - f_p(a)] \times Stock_p(j,a)$$

Eq. 9.3

In the standards case, there is also a second term that represents the extended repair stock that has been in use for six years following the repair date (see section 9.4 for discussion of extended repair).

Shipments are directed to one of the three market segments:

$$Ship_p(j) = Rpl_p(j) + NC_p(j) + NO_p(j)$$

Eq. 9.4

Where:

$Rpl_p(j)$ = number of units of product p replaced in year j, which depends on removed units and units in demolished buildings,
$NC_p(j)$ = number of units installed in new construction of product p in year j, and
$NO_p(j)$ = number of units shipped to "new owners" of product p in year j.

9.2.2 Replacement Shipments

The shipments model assumes that units that are taken from demolished buildings, $Dem(j)$, are included in the mix of broken units $Rem_p(j)$. As the demolished units do not need to be replaced, they are deducted from $Rem_p(j)$ when calculating the required replacements, as represented by the following expression:

$$Rpl_p(j) = Rem_p(j) - Dem(j)$$

Eq. 9.5

When a boiler fails, it is removed from the stock or is repaired for extended use. The following retirement function $r_p(a)$ is used to represent the probability that a unit will fail at age a.

$$Rem_p(j) = \sum_a r_p(a) \times Stock_p(j,a)$$

Eq. 9.6

Retirement functions and product lifetimes are discussed in more detail in chapter 8.

In each year, products are removed from demolished buildings. As represented by the following expression, the shipments model assumes that the saturation of the product in the demolished buildings is the same as that of the overall building population.

$$Dem(j) = D(j) \times sat(p, j-1)$$

Eq. 9.7

Where:

$D(j)$ = number of demolished buildings,
$Dem\ (j)$ = number of products demolished in analysis year j, and
$sat(p,j)$ = saturation of products of product class p for all buildings in year j.

The number of demolished buildings is calculated by:

$$D(j) = H_Stock(j-1) + H_Starts(j) - H_Stock(j)$$

Eq. 9.8

Where:

$H_Stock\ (j)$ = number of housing units in analysis year j, and
$H_Starts(j)$ = number of new housing units in year j.

9.2.3 Shipments to New Construction

DOE multiplied new construction market saturations by projections of new housing units (residential) or floor space (commercial) to estimate shipments to the new construction market segment. On a product class basis, the determination of shipments to new construction is represented by the following expression:

$$NC_p(j) = NC_Starts_res(j) \times NC_Sat_res_p(j) + NC_FloorSpace_com(j) \times NC_NumBoilersPerUnitFloorSpace_com_p(j)$$

Eq. 9.9

Where:

$NC_Starts_res(j)$ = number of new residential housing starts in year j,
$NC_Sat_res_p(j)$ = new residential housing saturation for each product class p and year j,
$NC_FloorSpace_com(j)$ = new commercial building floor space added in year j, and
$NC_NumBoilersPerUnitFloorSpace_com_p(j)$ = number of boilers per unit of commercial building floor space for each product class p and year j.

9.2.4 Shipments to New Owners

The third market segment consists of new owners of products in a given product class, and also includes an adjustment for switching to a different product class. Because there are no data on the extent of these phenomena, DOE estimated historical shipments to this market segment as a residual, using the following equation:

$$NO\ (j) = Shipment\ \ (j) - [RU(j) + NU(j)]$$

Eq. 9.10

Where:

j = year where historical shipment data is available,
$NO(j)$ = new owners (if positive) or adjustment for switching (if negative) for year j,
$Shipment(j)$ = historical shipment in year j,
$RU(j)$ = estimated replacement units in year j, and
$NU(j)$ = new units for new homes in year j.

9.3 DATA INPUTS AND SUPPORTING CALCULATIONS FOR SHIPMENTS IN THE NO-NEW-STANDARDS CASE

9.3.1 Historical Shipments for Residential Boilers

DOE used historical shipments data (*i.e.*, domestic shipments and imports) mainly from *Appliance Magazine* and the Air-Conditioning, Heating & Refrigeration Institute (AHRI)[b] to populate its shipments model for residential boilers. *Appliance Magazine* published publically available gas-fired and oil-fired boiler data from 1960 to 2008.[1,2]AHRI also submitted historical gas-fired and oil-fired boiler data from 1970 to 2003 to DOE during the 2007 Furnace and Boiler Standards Rulemaking process with disaggregated values between hot water and steam, by input capacity, and by state.[3] Recently, AHRI provided similar confidential data between 2003-2012 to Lawrence Berkeley National Laboratory (LBNL).[4] This data is not complete because it is non-continuous; is not fully disaggregated between product classes; includes a fraction of commercial boiler shipments; does not include all boiler types; and does not include all residential boiler manufacturers. Therefore, DOE adjusted the historical shipments data from *Appliance Magazine* and AHRI to take this into account. For electric boilers, DOE had limited historical shipment data. DOE estimated that that electric boilers are approximately 5 percent of total residential boiler shipments based on data from Energy Information Administration (EIA)'s *2009 Residential Energy Consumption Survey* (RECS 2009) and EIA's *2003 Commercial Buildings Energy Consumption Survey* (CBECS 2003).[5,6] Further details about historical shipments are described in appendix 9A. Figure 9.3.1 summarizes the historical shipments data that DOE assembled.

[b] Previously Gas Appliance Manufacturers Association (GAMA).

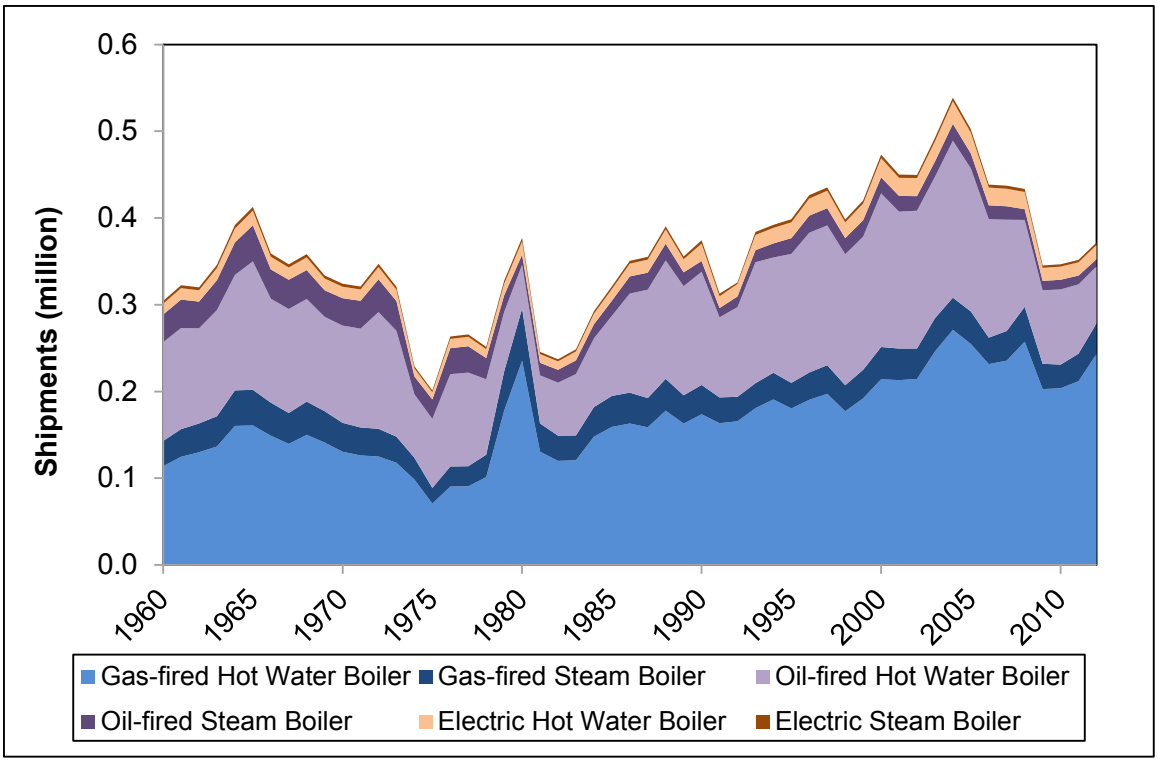

Figure 9.3.1 Historical Shipments of Residential Boilers, 1960-2012

9.3.2 Survival Function for Residential Boilers

As described in appendix 8F, DOE defines lifetime as the age when a product is retired from service and uses survival function to model the probability distribution of retirements of the product. The survival function, which is assumed to have the form of a cumulative Weibull distribution, provides an estimate of the average and medium appliances lifetime. DOE assumed an average lifetime value of 26.6 years for gas-fired hot water boilers and electric hot water boilers, 23.6 years for gas-fired steam boilers and electric steam boilers, 24.7 for oil-fired hot water boilers, and 19.3 years for oil-fired steam boilers.[c] The survival functions used for the analysis are shown in Figure 9.3.2.

[c] DOE had no lifetime data for electric boilers, so it used the same lifetime and survival function as the corresponding gas-fired boiler.

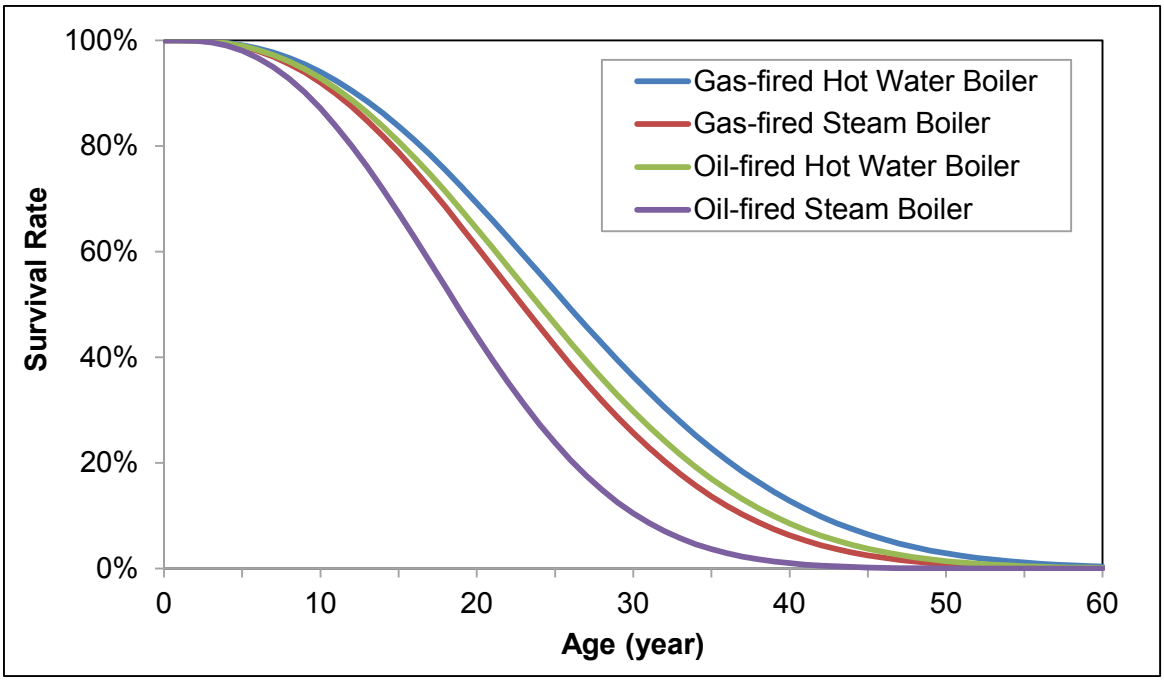

Figure 9.3.2 Survival Function for Residential Boilers

9.3.3 Residential Boiler Shipments to Commercial Buildings

A fraction of residential boilers are shipped to commercial buildings; therefore, DOE considered the future shipments of residential boilers to commercial buildings in this analysis. There is no historical shipments data disaggregating shipments DOE used RECS 2009 and EIA's *2003 Commercial Buildings Energy Consumption Survey* (CBECS 2003)[6] to determine the number of residential boilers in residential and commercial applications. DOE estimated that residential boilers shipped to commercial buildings accounted for 7 percent of the total historical shipments of residential gas boilers, 5 percent of residential oil boilers, and 31 percent of residential electric boilers. The methodology to determine the fraction of residential boilers shipped to commercial buildings are described in appendix 9A.

9.3.4 Residential Boiler Shipments to New Construction

DOE determined historical new residential housing starts up to 2012 by using U.S. Census data[7,8] and determined historical commercial floor space up to 2012 from the NEMS data published in EIA's *Annual Energy Outlook 2015* (*AEO 2015*).[9] From 2013 to 2040 (the last year in *AEO 2015*), DOE used projections from *AEO 2015* projections. After 2040, DOE assumed that the housing starts and commercial floor space would remain constant at the 2040 projected value from *AEO 2015*.

DOE developed new housing boiler type market saturations from *Characteristics of New Housing* data from the U.S. Census Bureau,[10] RECS 2009, and CBECS 2003. For single family homes, DOE used the U.S. Census data to estimate national saturations for residential boilers in

new single-family houses in the 1999-2013 time period. DOE estimated future national saturations in single family houses using the average saturation in the 2010−2013 by Census division. It derived national saturation values over time using weights based on the *AEO 2015* housing forecast of new single family starts by Census division. For multi-family, DOE used RECS 2009 data to estimate the average national saturations for residential boilers from 1990-2009. DOE used the average from 1990-2009 national saturations in multi-family buildings to estimate the future national saturation value and assumed value would remain constant over the analysis period. For manufactured homes, DOE estimated that the future national saturations would be 0 percent based on RECS 2009 data. For commercial buildings, DOE used CBECS 2003 data to estimate the average national fractions of the total new floor space for residential boilers from 1990-2003. DOE used the average from 1990-2003 national fractions of the total new floor space in commercial buildings to estimate the future national saturation value and assumed value would remain constant over the analysis period.

Table 9.3.1 shows the projected market saturations of residential boilers by building type in 2021. DOE assumed that steam boilers are primarily a replacement product, so the new construction saturations for steam boilers in single family homes were set to 0 percent.

Table 9.3.1 Saturations of Residential Boilers in New Construction in 2021

Product Class	Single Family (Percentage of Housing)	Multi-Family (Percentage of Housing)	Manufactured Home (Percentage of Housing)	Commercial Buildings (Number of Boilers per million ft^2)
Gas-fired Hot Water Boiler	1.09%	1.41%	0.00%	2.48
Gas-fired Steam Boiler*	-	-	-	-
Oil-fired Hot Water Boiler	0.19%	0.13%	0.00%	0.25
Oil-fired Steam Boiler*	-	-	-	-
Electric Hot Water Boiler	0.19%	0.10%	0.00%	1.06
Electric Steam Boiler*	-	-	-	-

* DOE assumed that there are no shipments of steam boilers to the new construction market.

9.3.5 Residential Boiler Shipments to New Owners

The new owners primarily consist of households that during a major remodel add hydronic heating using a gas-fired hot water boiler and households that choose to install a boiler for a hydronic air handler to replace a gas furnace. For this analysis, new owners also include households switching between different residential boiler product classes.

9.3.5.1 Modelled Shipments to New Owners

DOE based the fraction of new owners on a comparison between 2010-2012 historical shipments and DOE's shipments model estimates for the same years, which shows a large number of shipments that are not part of the estimated new construction and replacement shipments. DOE assumed that these additional shipments are part of the new owner market segment. Table 9.3.2 shows the modeled residential boiler replacement and new owner shipments from 2010-2012. The new owner shipments in this table are derived as the difference between historical shipments and modeled new construction and replacement shipments as well as adjusted for a fraction of switching between product classes (as described in the product switching section below). DOE assumed that the fraction calculated for gas-fired hot water boilers are related to new owners who are not switching from another residential boiler product class (estimated to be 25 percent in 2013). DOE assumes that this fraction of gas-fired hot water boilers decreases over time from 22 percent in 2021 to 11 percent in 2050. The remainder of the (negative) fractions are assumed to be product classes net product switching to other boiler product classes, with no fraction of new owners who are not switching from another product class: -12 percent for gas-fired steam boilers, -30 percent for oil-fired hot water boilers, and -40 percent for oil-fired steam boilers.

Table 9.3.2 Modeled Residential Boilers Replacement and New Owner Shipments from 2010-2012

Product Class	Estimated Replacement Shipments (2010-2012) *million*	Estimated New Owner Shipments (2010-2012) *million*	Fraction of New Owner to Replacement Shipments
Gas-fired Hot Water Boiler	0.414	0.104	25%
Gas-fired Steam Boiler	0.091	-0.011	-12%
Oil-fired Hot Water Boiler	0.311	-0.092	-30%
Oil-fired Steam Boiler	0.050	-0.020	-40%

9.3.5.2 Product Switching Between Boiler Product Classes

For replacement units, DOE estimated product switching between different residential boiler product classes and fuel types (steam to hot water and oil to gas) based on stakeholder input on market trends and historical shipment data from 2010 to 2012.[4] For this analysis, DOE did not consider product switching to alternative space heating systems (*e.g.*, furnaces, heat pumps or ductless mini-splits).

The fractions of consumers that switch to other product classes (negative) or new owners (positive) for each product class are 25 percent, -12 percent, -30 percent, and -40 percent for gas-fired hot water boilers, gas-fired steam boilers, oil-fired hot water boilers, and oil-fired steam boilers, respectively, from 2010 to 2012. DOE also estimated that the amount of product

switching from electric boilers to other product classes to be negligible because these boilers are generally located in areas where alternatives to electricity are lacking or the heating load is low.

DOE estimated that among the 40 percent of oil-fired steam boilers that switched to other product class, 75 percent switched to gas-fired steam boilers, 20 percent switched to oil-fired hot water boilers, and 5 percent switched to gas-fired hot water boilers. DOE also estimated that 12 percent of gas-fired steam boilers and 30 percent of oil-fired hot water boilers that switched to other product classes all switched to gas-fired hot water boilers.

Figure 9.3.3 illustrates DOE's product switching estimates between the residential boiler product classes in future years: 30 percent of oil-fired steam boiler replacement units will be replaced by gas-fired steam boilers, 8 percent of oil-fired steam boiler replacement units will be replaced by oil-fired hot water boilers, and 2 percent of oil-fired steam boiler replacement units will be replaced by gas-fired hot water boilers. Similarly, DOE estimated that 12 percent of gas-fired steam boiler replacement units will be replaced by gas-fired hot water boilers and 30 percent of oil-fired hot water boiler replacement units will be replaced by gas-fired hot water boilers.

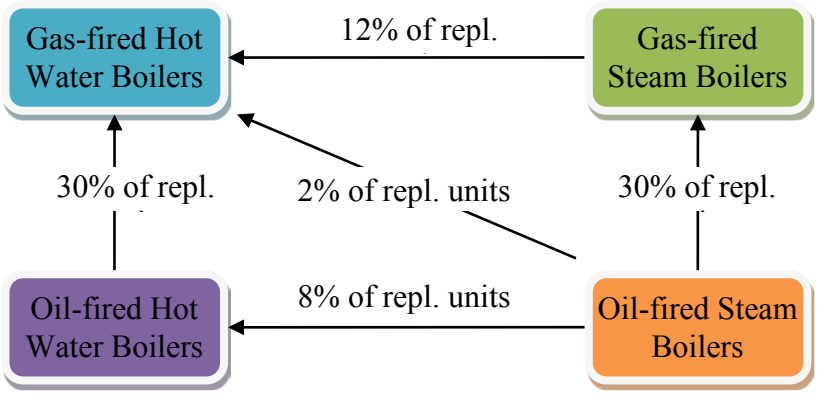

Figure 9.3.3 Product Switching Among Residential Boiler Product Classes

The product switching results from the shipments model from 2021-2050 are summarized in Table 9.3.3 (negative values represent the number of boiler units replaced by other product classes and positive values indicate the number of boiler units used as replacements for other product classes).

Table 9.3.3 Product Switching From 2021-2050

Product Class	Net Product Switching (thousands of units)
Gas-fired Hot Water Boiler	948
Gas-fired Steam Boiler	-22
Oil-fired Hot Water Boiler	-811
Oil-fired Steam Boiler	-115
Electric Hot Water Boiler	0
Electric Steam Boiler	0

9.4 IMPACT OF CONSIDERED STANDARDS ON SHIPMENTS

DOE evaluated the potential for product switching between boiler product classes and to other types of heating systems. Incentive for such switching would only exist if the amended standards were to require efficiencies for boilers that would entail a significantly higher installed cost than the other heating options.[d] Because DOE is not proposing an amended standard that would require significantly higher installed cost (such as condensing technology), DOE has concluded that consumer switching away from boilers that are compliant with the proposed standards would be rare.

For replacements, consumer decisions to purchase or repair a boiler are influenced by the purchase price and operating cost of the product, and therefore may be different in the no-new-standards case and under standards cases at different efficiency levels (ELs).[e] These decisions are modeled by estimating the purchase price elasticity for boilers. The purchase price elasticity is defined as the change in the percentage of consumers acquiring a boiler divided by a change in the *relative price* (defined below) for that product. This elasticity, along with information obtained from the life-cycle cost (LCC) and payback period (PBP) analysis on the change in purchase price and operating costs at different ELs, are used in the shipments model to estimate the change in shipments under potential standards at different ELs.

[d] Even at higher installation costs, the product switching could be limited. Switching from gas-fired and oil-fired to electric boilers includes high installation costs for upgrading the electrical system of a home and might require new installation infrastructure to replace the existing electrical service to accommodate the high amperage required for an electric boiler. Additionally, owners of gas-fired boilers are less likely to switch to other fuel types because oil and electricity prices are currently much higher than natural gas prices. Also, DOE estimated that switching from a hydronic system using a boiler to an air-distribution heating system with a furnace or heat pump or to a ductless mini-split heat pump would be expensive and in many cases would require the additional cost of installing a separate water heater, upgrading existing electrical service, or installing new ducts, which would likely only be done as part of a major renovation.

[e] Because the percentage change in the cost of boilers due to amended residential boiler standards is relatively small, DOE assumed that the new construction market is unaffected by changes in either the total installed cost or operating costs of the product. That is, home builders are not likely to choose to not install a boiler if the installed cost rises by a small amount.

DOE used a study that conducted a literature review and an analysis of appliance price and efficiency data to estimate the effects on product shipments from increases in product purchase price and product energy efficiency.[11]

Existing studies of appliance markets suggest that the demand for durable goods, such as appliances, is price-inelastic. Other information in the literature suggests that appliances are a normal good, so that rising incomes increase the demand for appliances, and that consumer behavior reflects relatively high implicit discount rates[f] when comparing appliance prices and appliance operating costs.

The study used the available data for the period 1989-2009 on household appliance purchases to evaluate broad market trends and conduct simple regression analyses. These data indicate that there has been a rise in appliance shipments and a decline in appliance purchase price and operating costs over the time period. Other relevant variables include household income, which has also risen during this time, new residential construction, and stock failures of existing appliances. Using these data, the study performed a regression analysis to estimate two parameters, the price elasticity of appliance demand and the shipments response to appliance efficiency, defined as follows:

$$\varepsilon_d = \frac{\frac{\Delta q}{q}}{\frac{\Delta p}{p}}$$

Eq. 9.11

Where:

ε_d = price elasticity of demand,
q = quantity of shipments, and
p = price

$$\varepsilon_e = \frac{\frac{\Delta q}{q}}{\frac{\Delta e}{e}}$$

Eq. 9.12

Where:

ε_e = "efficiency elasticity",

[f] An implicit discount rate refers to a rate than can be inferred from observed consumer behavior with regard to future operating cost savings realized from more-efficient appliances. An implicit discount rate is not a true discount rate because the observed consumer behavior is affected by lack of information, high transaction costs, and other market barriers. However, implicit discount rates can predict consumer purchase behavior with respect to energy-efficient appliances. A high implicit discount rate with regard to operating costs means that consumer reflects a high discounting of future operating cost savings realized from more-efficient appliances. In other words, consumers are much more concerned with higher purchase prices.

q = quantity of shipments, and
e = product efficiency.

The regression analysis suggests that the price elasticity of demand, based on aggregated data for five residential appliances, is -0.45. Thus, for example, a price increase of 10 percent would result in a shipments decrease of 4.5 percent, *all other factors held constant*. The efficiency elasticity is estimated to be +0.2 (*i.e.,* a 10 percent efficiency improvement would result in a shipments increase of 2%, *all else equal*).[g]

The price elasticity estimate of -0.45 is consistent with estimates of appliance and durables price effects in the literature. Nevertheless, the study stresses that the measure is based on a small data set, using simple statistical analysis. More importantly, the measure is based on the assumption that economic variables, including purchase price, operating costs, and household income, explain most of the trend in appliances per household in the United States between 1989 and 2009. Changes in appliance quality and consumer preferences may have occurred during this period, but DOE did not account for them in this analysis. Despite the uncertainties, DOE believes that its estimates provide a reasonable assessment of the effect that purchase price and efficiency have on product shipments.

Because DOE's projections of shipments and national impacts from potential standards consider a 30-year period, DOE needed to consider how price elasticity evolves in the years after a new standard takes effect. DOE considered the price elasticity developed above to be a short-term value, but was unable to identify sources specific to appliances sufficient model differences in short- and long-term price elasticities. Therefore, to estimate how the price elasticity changes through time, DOE relied on a study pertaining to automobiles.[12] This study shows that the price elasticity of demand for automobiles changes in the years following a change in purchase price, a trend also observed in appliances and other durables.[13,h] As time passes since the change in purchase price, the price elasticity becomes more inelastic until it reaches a terminal value around the tenth year after the price change. Table 9.4.1 shows the relative change over time in the price elasticity of demand for automobiles. As shown in the table, DOE developed a time series of price elasticity for residential appliances based on the relative change over time in the price elasticity of demand for automobiles. For years not shown in the table, DOE performed a linear interpolation to obtain the price elasticity.

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[g] Note that DOE previously combined these impacts in a variable termed "relative price elasticity." Price and efficiency impacts are now separated for greater consistency with price elasticity measures reported in the literature.
[h] DOE relies on Hymens et al. (1970) for efficiency scaling factors because it provides the greatest detail out of the available studies on price elasticity over time.

Table 9.4.1 Change in Price Elasticity and Efficiency Elasticity Following a Purchase Price Change

	Years Following Price Change					
	1	**2**	**3**	**5**	**10**	**20**
Relative Change in Elasticity to first year	1.00	0.78	0.63	0.46	0.35	0.33
Price Elasticity	-0.45	-0.35	-0.28	-0.21	-0.16	-0.15
Efficiency Elasticity	0.20	0.16	0.13	0.09	0.07	0.07

Using the following equation, DOE estimated standards-case shipments by considering the effect of price and efficiency. Note that in the equation below, the *price*, the *price* elasticity, the *efficiency,* and the *efficiency elasticity* are functions of the year because they change with time.

$$dRS_p(j) = \max\left[\left|\varepsilon_d(j)\right| \times \Delta P_p(j) - \left|\varepsilon_e(j)\right| \times \Delta E_p(j)\,,\,0\right]$$

Eq. 9.13

Where:

$dRS_p(j)$ = percentage replacement shipments drop for product class *p* in year *j*,

$\varepsilon_d(j)$ = price elasticity in year *j* (equals -0.45 for year 1),

$\Delta P_p(j)$ =change in price due to a standard level for product class *p* in year *j*, %

$\varepsilon_e(j)$ = efficiency elasticity in year *j* (equals 0.20 for year 1), and

$\Delta E_p(j)$ = change in efficiency due to a standard level for product class *p* in year *j*, %.

To model the impact of the increase in relative price from a particular standard level on residential boiler shipments, DOE assumed that the affected consumers would repair their product rather than replace it, extending the life of the product by 6 years. When the extended repaired units fail after 6 more years, they will be replaced with new ones.

The model calculates the relative percentage replacement shipments drop, $dRS_p(j)$, due to a combined effect of the product price increase and efficiency improvement from a particular standard level.

The number of failed boilers that will be repaired instead of being replaced is calculated as follows:

$$XR_p(j) = \left[Rem_p(j) - Dem_p(j)\right] \times dRS_p(j), \qquad j \geq 2021$$

Eq. 9.14

Where:

$dRS_p(j)$ = percentage replacement shipments drop for product class *p* in year *j*,

j = analysis year,
$Rem_p(j)$ = retiring units of product class p in year j, and
$Dem_p(j)$ = number of units of product class p removed with demolished buildings in analysis year j.

The number of units of replacement shipments is then calculated:

$$Rpl_p(j) = \left[Rem_p(j) - Dem_p(j)\right] - XR_p(j), \qquad for\ 2021 \le j < (2021+6)$$
$$Rpl_p(j) = \left[Rem_p(j) - Dem_p(j)\right] - XR_p(j) + XR_p(j-6), \qquad for\ j \ge (2021+6)$$

Eq. 9.15

Where:

$Rem_p(j)$ = retiring units of product class p in year j,
$Dem_p(j)$ = number of units of product class p removed with demolished buildings in analysis year j,
$XR_p(j)$= extended repair units of product class p in year j, and
$Rpl_p(j)$ = replacement units of product class p in year j.

9.5 RESULTS

As detailed in chapter 10, DOE created trial standard levels (TSLs) that combine specific efficiency levels across product classes. Table 9.5.1 presents the TSLs and the corresponding product class efficiency levels that DOE considered for residential boiler AFUE standards. 0 presents the TSLs and the corresponding product class efficiency levels that DOE considered for residential boiler standby mode and off mode power consumption.

Table 9.5.1 Trial Standard Levels for AFUE Standards (Efficiency Level)

Product Class	TSL 1		TSL 2		TSL 3		TSL 4		TSL 5	
	EL	AFUE	EL	AFUE	EL	AFUE	EL	AFUE	EL	AFUE
Gas-fired Hot Water Boiler	1	83%	1	83%	2	84%	4	90%	6	96%
Gas-fired Steam Boiler	1	82%	1	82%	1	82%	1	82%	2	83%
Oil-fired Hot Water Boiler	1	85%	2	86%	2	86%	3	91%	3	91%
Oil-fired Steam Boiler	1	84%	1	84%	2	85%	3	86%	3	86%

Table 9.5.2 Trial Standard Levels for Standby and Off Mode Standards (Efficiency Level)

Product Class	TSL 1		TSL 2		TSL 3	
	EL	Power (watt)	EL	Power (watt)	EL	Power (watt)
Gas-fired Hot Water Boiler	1	10.0	2	9.7	3	9.0
Gas-fired Steam Boiler	1	9.0	2	8.7	3	8.0
Oil-fired Hot Water Boiler	1	12.0	2	11.7	3	11.0
Oil-fired Steam Boiler	1	12.0	2	11.7	3	11.0
Electric Hot Water Boiler	1	9.0	2	8.7	3	8.0
Electric Steam Boiler	1	9.0	2	8.7	3	8.0

Figure 9.5.1 shows the historical and projected shipments of residential boilers by product class. The shipments of gas-fired steam boilers, oil-fired hot water boilers, and oil-fired steam boilers decrease over time due to product switching from steam to hot water and from oil to gas. The shipments of gas-fired hot water boilers increase due to product switching and the associated shipments to new owners. Electric boilers only account for a small fraction of the total shipments of residential boilers. The shipments of electric hot water boilers slightly increase over the analysis period (2021-2050) while the shipments of electric steam boilers slightly decrease over the analysis period (2021-2050). The no-new-standards case shipments for AFUE and standby mode and off mode standards are identical.

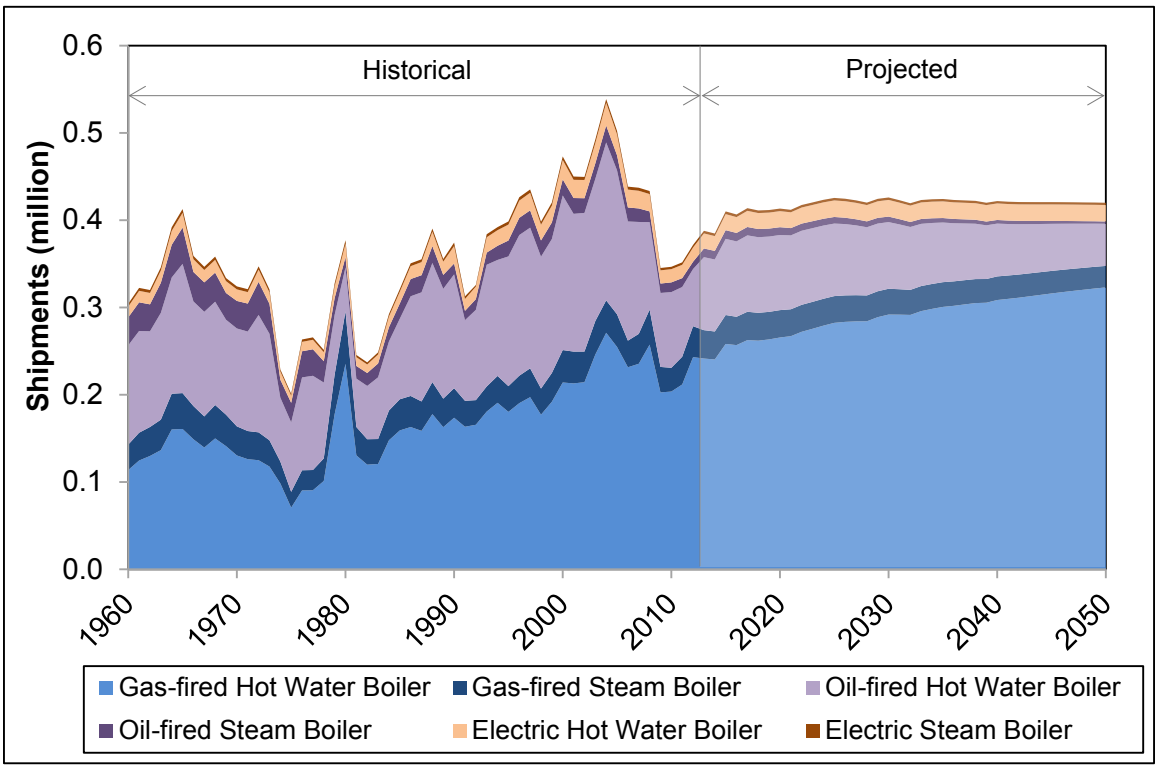

Figure 9.5.1 Historical and Projected No-New-Standards Case Shipments for Residential Boilers by Product Class, 1960-2050

Figure 9.5.2 shows projected shipments of residential boilers by market segment. As shown in the Figure 9.5.2, replacements comprise the largest fraction of the shipments, followed by new owners and then new construction.

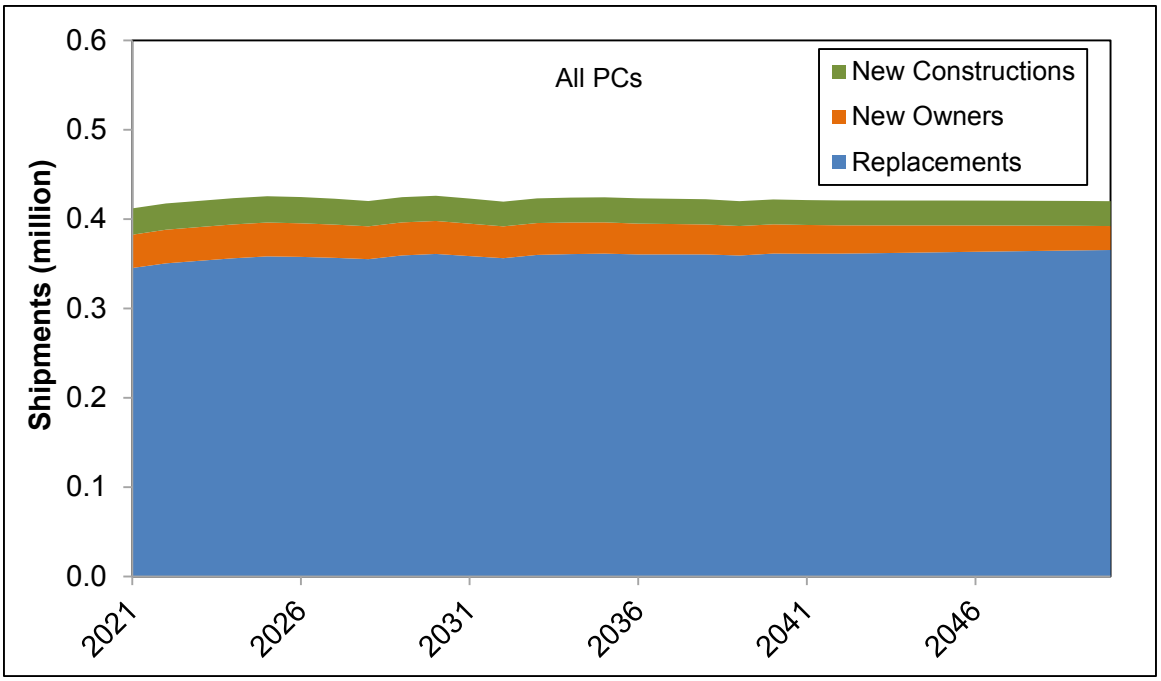

Figure 9.5.2 Projected No-New-Standards Case Shipments for Residential Boilers by Market Segment, 2021-2050

Figure 9.5.3 through Figure 9.5.6 show the total projected shipments of gas-fired hot water boilers, gas-fired steam boilers, oil-fired hot water boilers, and oil-fired steam boilers in the AFUE no-new-standards and standards cases, respectively. Because the elasticity is modeled as a delayed replacement of boiler products, the projection for the ELs shows a decline in the early years, but an increase in later years once the delayed replacements are finally made. As explained above, the elasticity parameter decreases over time, so the impact of the standards on shipments diminishes. For standby and off mode standards, the total projected shipments are assumed to be the same between the no-new-standards and standards cases.

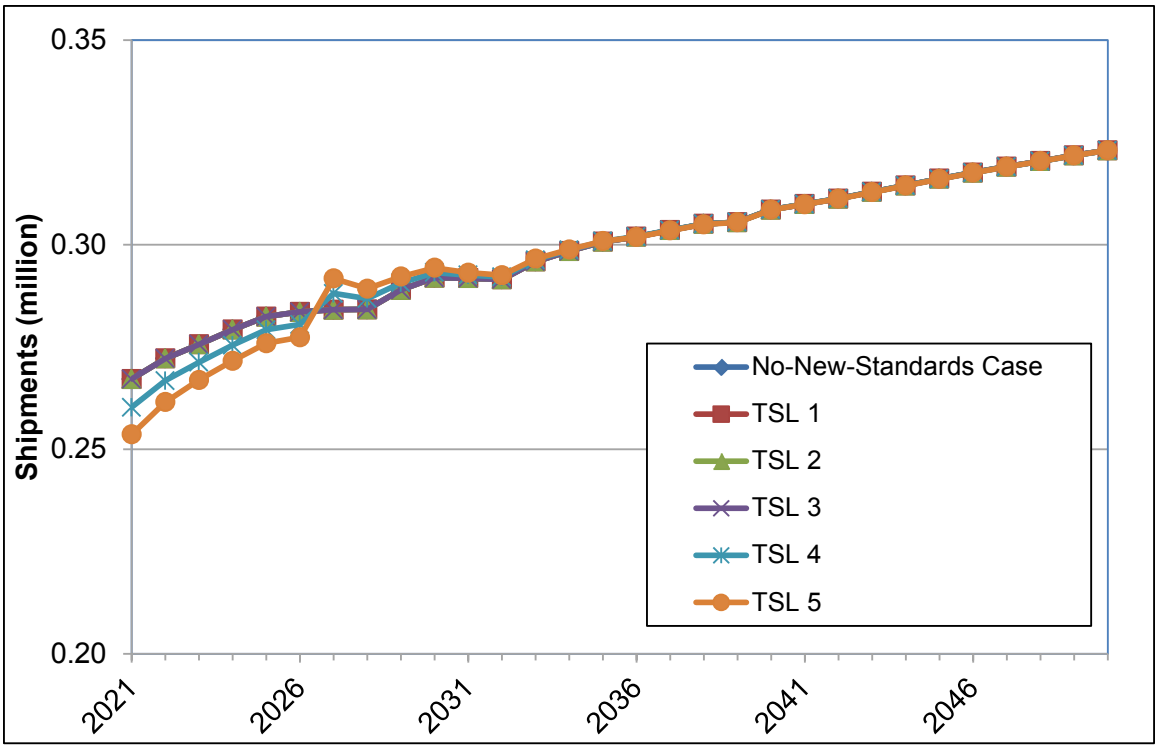

Figure 9.5.3 Total Projected Shipments of Residential Gas-fired Hot Water Boilers in the No-New-Standards Case and Each Standards Case, 2021-2050

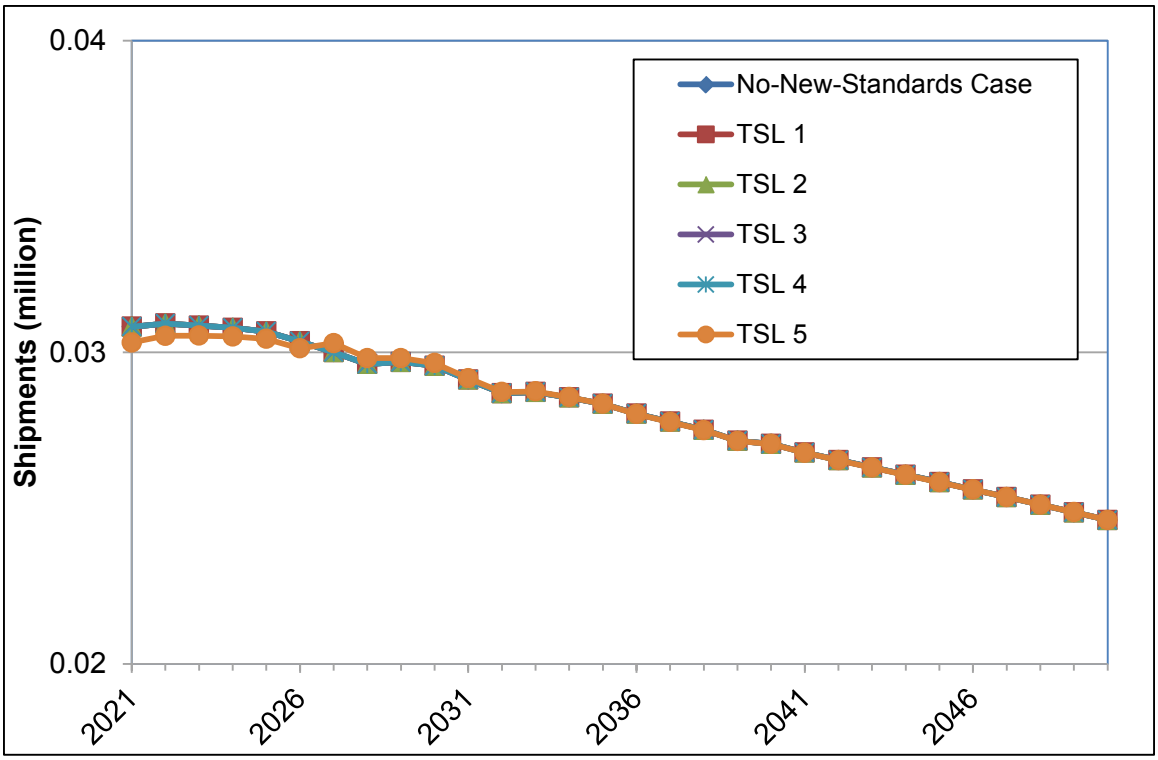

Figure 9.5.4 Total Projected Shipments of Residential Gas-Fired Steam Boilers in the No-New-Standards Case and Each Standards Case, 2021-2050

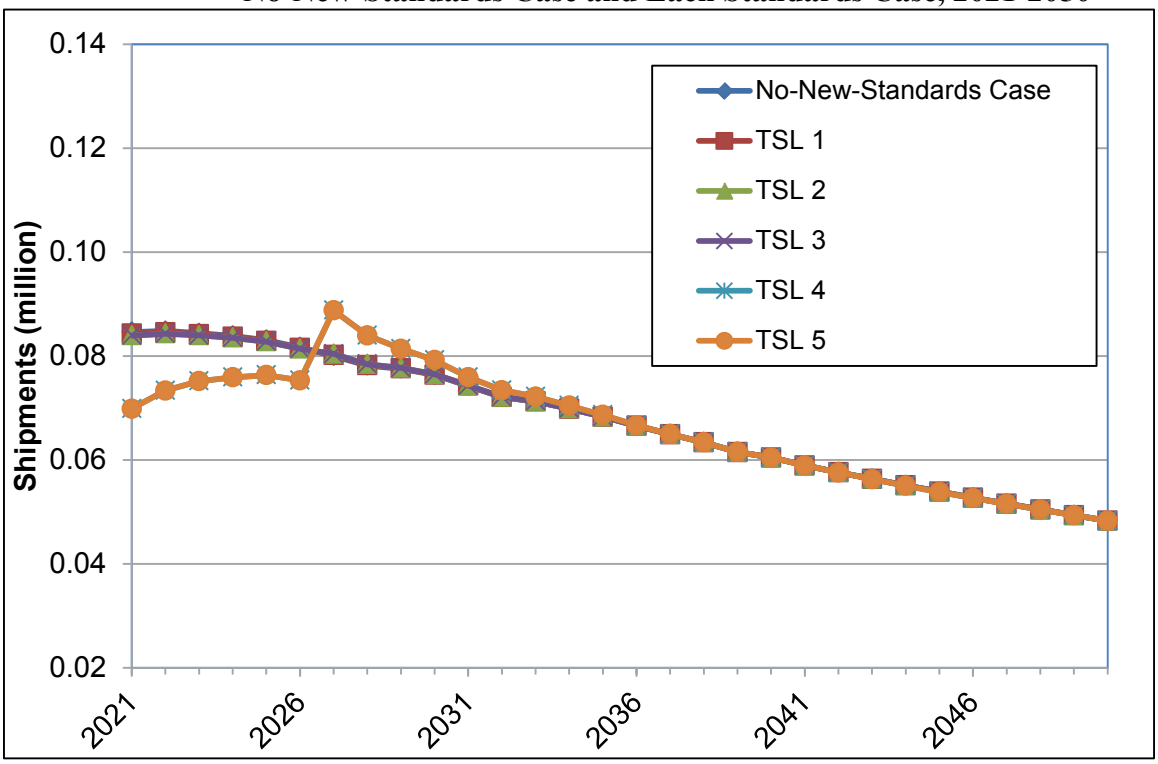

Figure 9.5.5 Total Projected Shipments of Residential Oil-fired Hot Water Boilers in the No-New-Standards Case and Each Standards Case, 2021-2050

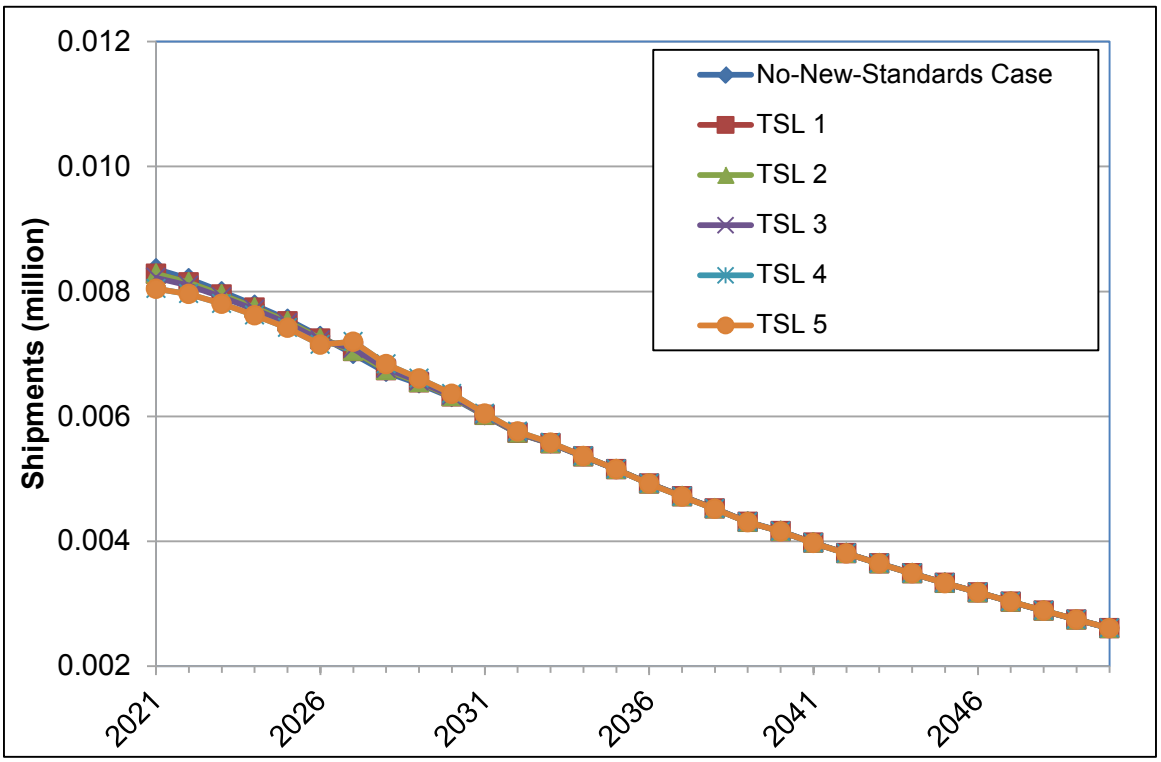

Figure 9.5.6 Total Projected Shipments of Residential Oil-Fired Steam Boilers in the No-New-Standards Case and Each Standards Case, 2021-2050

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APPENDIX 9A. ADDITIONAL DATA ON SHIPMENTS OF RESIDENTIAL BOILERS

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APPENDIX 9A. ADDITIONAL DATA ON SHIPMENTS OF RESIDENTIAL BOILERS

9A.1 INTRODUCTION

This appendix includes the data references and methodology for determining the historical shipments for residential boilers and the fraction of residential boilers shipped to commercial buildings.

DOE used historical domestic and imports boiler shipments data from *Appliance Magazine* and the Air-Conditioning, Heating & Refrigeration Institute (AHRI)[a] to populate its shipments model for residential boilers.[1, 2, 3]

DOE derived the fraction of residential boiler shipments used in commercial buildings by using data from Energy Information Administration (EIA)'s 2009 Residential Energy Consumption Survey (RECS 2009) and EIA's 2003 Commercial Building Energy Consumption Survey (CBECS 2003).[4, 5]

9A.2 DERIVATION OF HISTORICAL RESIDENTIAL BOILER SHIPMENTS

Appliance Magazine published publically available gas-fired and oil-fired boiler data from 1960 to 2008.[1] During the 2007 furnace and boiler standard rulemaking, AHRI also submitted to DOE historical gas-fired and oil-fired boiler data from 1970 to 2003 disaggregated between hot water and steam, by input capacity, and by state.[2] Recently, AHRI provided similar confidential data between 2003-2012 to Lawrence Berkeley National Laboratory (LBNL).[3] DOE adjusted the historical shipments data from *Appliance Magazine* and AHRI because it is only available for certain years; is not fully disaggregated between product classes; includes a fraction of commercial boiler shipments; does not include all boiler types; and does not include all residential boiler manufacturers.

For electric boilers, DOE had limited historical shipments data. DOE estimated that that electric boilers are approximately 3.4 percent of total residential boiler shipments based on data from RECS 2009.[4]

9A.2.1 Historical Data

9A.2.1.1 Appliance Magazine Gas-fired and Oil-fired Shipments Data

DOE collected annual shipments of total boilers (residential and commercial) disaggregated by fuel type from *Appliance Magazine* from 1960-2008 (data from 1987-1989 was not available).[1] AHRI is listed as the primary reference for the data reported by *Appliance Magazine*.

[a] Previously Gas Appliance Manufacturers Association (GAMA).

9A.2.1.2 AHRI Gas-fired and Oil-fired Shipments data

AHRI provided DOE annual boiler shipments data for residentially- and commercially-sized boilers during the 2007 furnace and boiler standard rulemaking from 1969-2003.[2] At that time, AHRI also provided shipments data disaggregated between hot water and steam, by input capacity, and by state. For this rulemaking, AHRI provided historical shipments data from 2003 to 2012; however, this data set has not been disclosed for confidentiality reasons.[3] In addition, disaggregated AHRI shipments data for 1993 is reported in a Pacific Northwest National Laboratory (PNNL) report,[6] and disaggregated shipments from 2003 to 2007[b] are reported in a 2009 California Climate Action Registry report.[7]

9A.2.1.3 Combined Appliance Magazine and AHRI Shipments data

For this analysis, DOE combined the *Appliance Magazine* data and AHRI data to determine the historical shipments. Historical shipments data from 1960-1968 is provided only by *Appliance Magazine*, and historical shipments data from 2009-2012 is provided only by AHRI. Figure 9A.2.1 shows the combined shipments data DOE used from 1960-2008 (2009-2012 data is not shown because it is confidential).[c] DOE found that these data:

1. Include commercial boiler shipments (input capacity at or above 300 kBtu/h);
2. Include mostly cast-iron and steel boilers shipments and do not include coil and tube type gas-fired hot water boilers and high efficiency (condensing) hot water boiler shipments;[d] and
3. Do not include shipments of hot water boilers from non-AHRI member manufacturers.[e]

[b] Shipments data for boilers below 250 kBtu/h output capacity is reported.
[c] AHRI provided LBNL with disaggregated residential gas-fired and oil-fired boiler shipments (boilers up to 250 kBtu/h output capacity) as well as coil and tube type gas-fired hot water boilers and high-efficiency (condensing) boiler shipments data from 2003-2012. For confidentiality, this data is not shown in Figure 9B.2.3.
[d] There are no coil and tube type steam boilers or condensing steam boiler models currently on the market.
[e] DOE did not find any non-AHRI steam boiler models currently on the market.

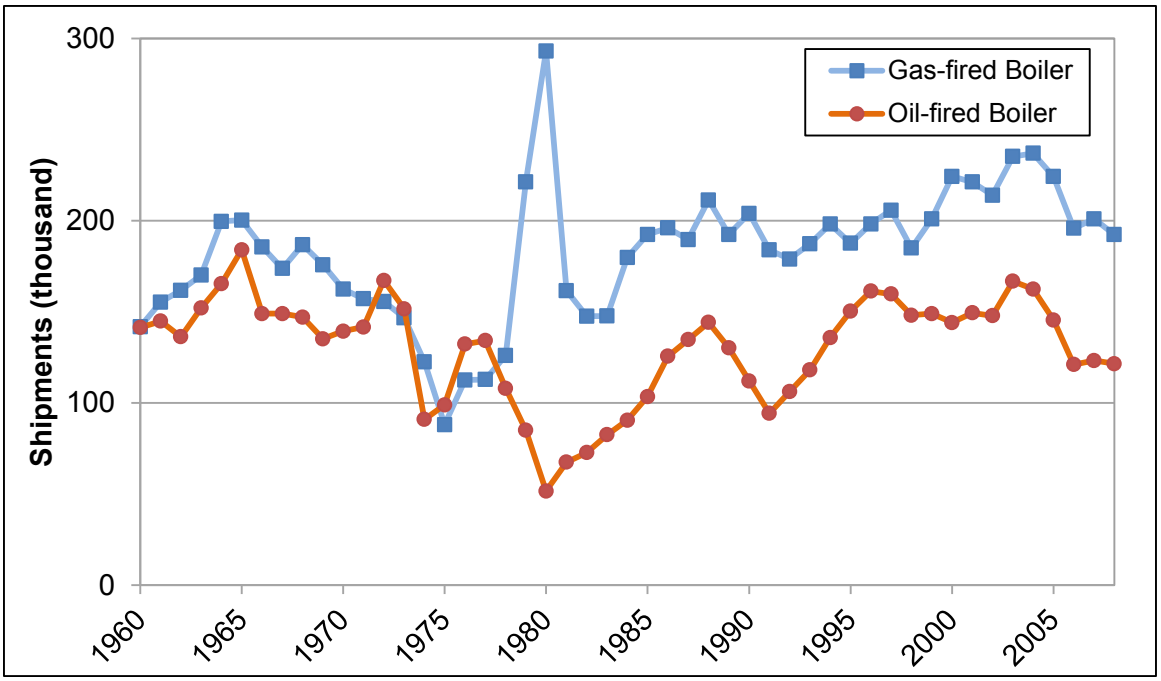

Figure 9A.2.1 Combined Historical Shipments Data of Gas-fired and Oil-fired Boilers, 1960-2008

9A.2.2 Methodology for Determining Historical Residential Shipments for Gas-fired and Oil-fired Boilers

DOE used the historical shipments data of all boilers from 1960-2012 from *Appliance Magazine* and AHRI data, as shown in Figure 9A.2.1 (2009-2012 data are not shown because it is confidential). Once the total shipments by fuel type ($Ship_{Total,f}$) were established, DOE disaggregated the shipments by product class (hot water and steam) and adjusted the shipments to take into account: the fraction of commercial boiler shipments, boiler types not included, and residential boiler manufacturers not included.[f] The following equations show how DOE adjusted the $Ship_{Total}$ to determine the final shipments for each product class:

$$Ship_{Res,HW,f} = \left(Ship_{Total,f} \times Frac_{Res,HW,f} + Ship_{OtherTypes,f}\right) \times AdjFactor_{Non-AHRI,f}$$, for hot water boilers, and

$$Ship_{Res,Steam,f} = Ship_{Total,f} \times Frac_{Res,Steam,f}$$, for steam boilers

Eq. 9A.1

Where:

[f] The adjustments for boiler types not included and residential boiler manufacturers not included only impacts hot water boiler shipments. DOE did not find other boiler types or manufacturers currently on the market for steam boilers.

f = fuel type (gas or oil),
$Ship_{Res,HW}$ = calculated shipments of residential hot water boilers,
$Ship_{Res,Steam}$ = calculated shipments of residential steam boilers,
$Ship_{Total}$ = shipments from the combined *Appliance Magazine* and AHRI data (see section 9A.2.1.3),
$Frac_{Res,HW}$ = fraction of cast-iron residential hot water boilers to total reported combined *Appliance Magazine* and AHRI boiler shipments (see section 9A.2.2.1),
$Ship_{OtherTypes}$ = number of shipments to other types of boilers not included in combined *Appliance Magazine* and AHRI data (see section 9A.2.2.2),
$AdjFactor_{non\text{-}AHRI}$ = adjustment factor accounting for the manufacturers not included in combined *Appliance Magazine* and AHRI data (see section 9A.2.2.3), and
$Frac_{Res,Steam}$ = fraction of cast-iron residential steam boilers to total reported combined *Appliance Magazine* and AHRI boiler shipments (see section 9A.2.2.1).

9A.2.2.1 Fraction of Residential Cast-Iron Hot Water and Steam Boilers to Total Combined Appliance Magazine and AHRI Shipments

Historically, the great majority of residential gas-fired and oil-fired boilers have been cast-iron boilers. The shipments of cast-iron boilers were calculated using the parameters $Ship_{Total}$ multiplied by $Frac_{Res,HW}$ for hot water shipments and $Ship_{Total}$ multiplied by $Frac_{Res,Steam}$ for steam boiler shipments in Eq. 9A.1. The $Frac_{Res,HW}$ and $Frac_{Res,Steam}$ parameters both 1) take into account the fraction of commercially sized boilers in $Ship_{Total}$ and 2) disaggregate between hot water and steam boilers, as described below. All steam boilers are cast iron boilers, but for hot water boilers, DOE separately accounted for boiler other than cast-iron boilers, as described in section 9A.2.2.2.

Disaggregation of Residentially- and Commercially-Sized Cast-Iron Boiler Shipments. The AHRI and *Appliance Magazine* historical shipments data include some commercially-sized boilers (greater than or equal to 300 kBtu/h input capacity).[g] To determine the shipments of residential cast-iron boilers from the total shipped boilers reported, DOE used boiler shipments data disaggregated by product class and output capacity bins from AHRI for 1970, 1980, 1990, 1993 (published in PNNL report), 2000, and 2003 to 2012.[2,3,6] Within the output capacity bins in this data, DOE assumed that the boilers with output capacities of less than 250 kBtu/h were residential boilers.[h] Table 9A.2.1 shows the 1993 shipments data published in PNNL's report and the estimated fraction of residential boilers.

[g] Energy Policy and Conservation Act (EPCA) defines a residential boiler as having a heat input rate of less than 300,000 Btu per hour for electric boilers and low pressure steam or hot water boilers.
[h] Although some residential and commercial units might have an output capacity above or below 250 kBtu/h, this is the bin best represents the residential boiler input capacity limit. For example, a 299 kBtu/h residential unit with an efficiency above 83 percent AFUE could have an output capacity above 250 kBtu/h. Similarly, a commercial 300 kBtu/h input capacity unit with an efficiency below 83 percent could have an output capacity below 250 kBtu/h.

Table 9A.2.1 Historical Cast-Iron Shipments of Boilers in 1993 from AHRI data

Output Capacity (kBtu/h)	HWGB	SGB	HWOB	SOB
<50	8,183	232	5	2
50-75	25,375	2,482	1,646	4
75-100	47,203	6,932	14,038	1,248
100-125	40,666	8,178	31,587	2,888
125-150	16,433	3,708	18,389	4,238
150-200	12,713	4,459	30,037	3,279
200-250	5,900	2,670	4,641	2,243
250-450	4,695	2,197	3,186	1,371
450-950	1,073	977	1,270	625
950-1500	256	431	628	451
>1500	179	487	1,101	723
Total	162,676	32,753	106,528	17,072
Fraction of Residential Boilers	96.2%	87.5%	94.2%	81.4%

Disaggregation of Cast-Iron Hot Water and Steam Boiler Shipments. The *Appliance Magazine* historical shipments data and some of the AHRI data were not disaggregated between hot water and steam boilers. As shown in Table 9A.2.2, DOE derived the fraction of cast-iron hot water boilers and steam boilers based on shipments data in 1970, 1980, 1990, 1993, 2000, and 2003 to 2007 from AHRI.[2,6,7] These shipments already exclude the commercial fraction because DOE only used data for boilers with an output capacity below 250 kBtu/h.

Table 9A.2.2 Historical Shipments of Cast-Iron Hot Water and Steam Boilers (Output Capacity Below 250 kBtu/h) Reported by AHRI

Year	Shipments of Gas Boiler (Cast-Iron)			Shipments of Oil Boiler (Cast-Iron)		
	Hot Water	Steam	Hot Water Fraction	Hot Water	Steam	Hot Water Fraction
1970	90,474	15,663	85.2%	53,992	12,393	81.3%
1980	214,095	60,131	78.1%	32,065	11,697	73.3%
1990	151,167	33,711	81.8%	85,446	12,446	87.3%
1993	156,473	28,661	84.5%	100,343	13,902	87.8%
2000	176,444	36,904	82.7%	98,857	18,555	84.2%
2003	186,627	38,105	83.0%	120,764	17,706	87.2%
2004	189,417	36,846	83.7%	133,288	19,460	87.3%
2005	179,717	37,127	82.9%	121,678	17,256	87.6%
2006	155,499	30,243	83.7%	99,801	16,016	86.2%
2007	147,873	33,932	81.3%	93,642	15,494	85.8%

The fractions of cast-iron hot water boilers and steam boilers in other years between 1970 and 2007 were interpolated, and the fraction of cast-iron hot water boilers before 1970 was assumed to be the same value as it was in 1970. The fractions of cast-iron hot water and steam boilers after 2007 were calculated using the confidential AHRI shipments data provided to LBNL from 2008 to 2012.[3]

Resulting Fractions. Figure 9A.2.2 and Figure 9A.2.3 show the estimated fractions of residential cast-iron hot water and steam boiler shipments to total cast-iron boiler shipments for gas-fired and oil-fired boilers, respectively. In the figures, the "other" boiler category includes both commercially sized boilers and other boiler types (such as steel, coil and tube type, and high efficiency (condensing) boilers discussed in section 9A.2.2.2).

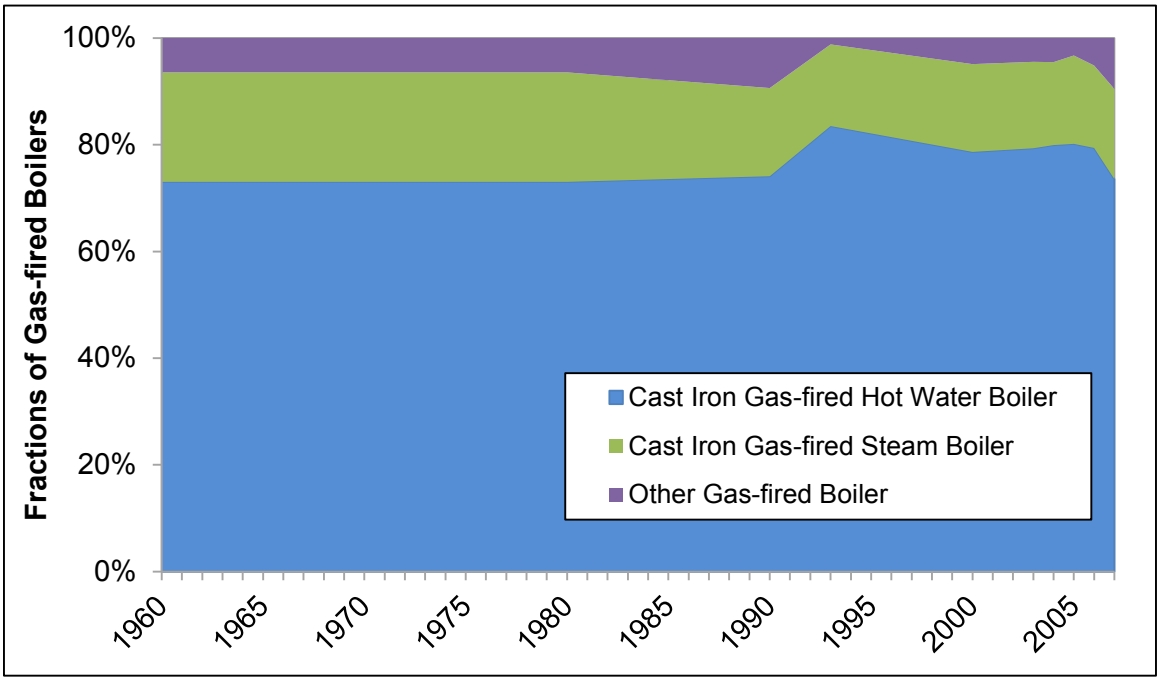

Figure 9A.2.2 Fractions of Residential Hot Water and Steam Cast-Iron Gas-fired Boilers to Total Combined Appliance Magazine and AHRI Shipments, 1960-2007

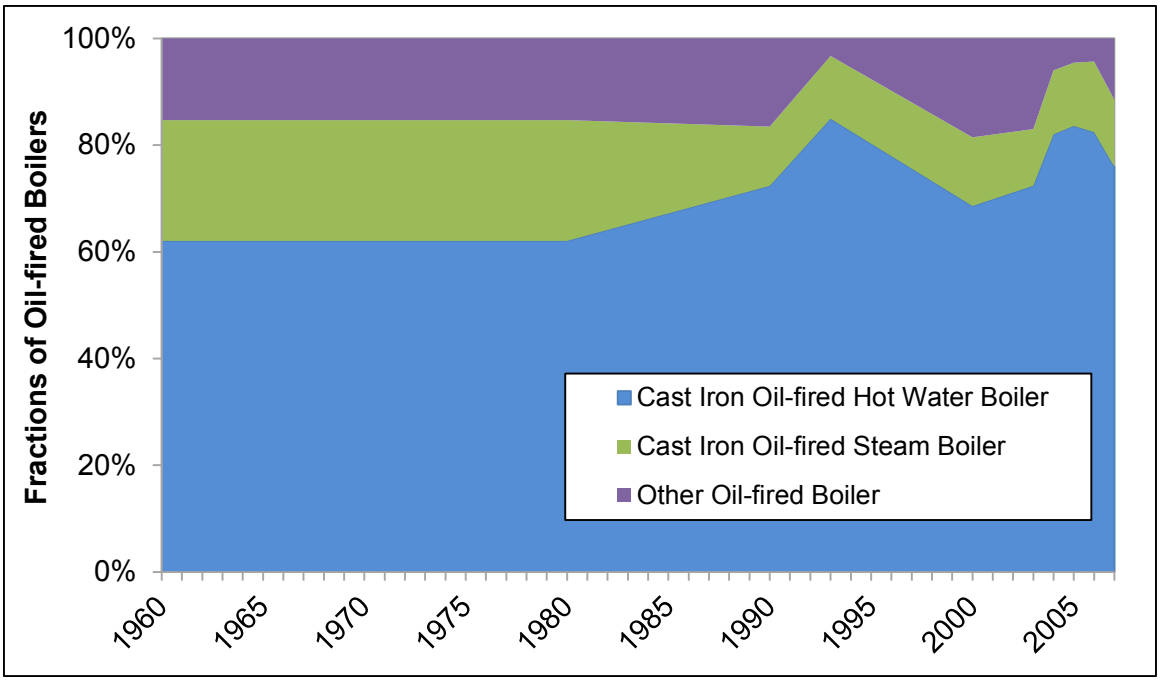

Figure 9A.2.3 Fractions of Residential Hot Water and Steam Cast-Iron Oil-fired Boilers to Total Combined Appliance Magazine and AHRI Shipments, 1960-2007

9A.2.2.2 Accounting for Other Boiler Types

In addition to cast-iron boilers, *Appliance Magazine* and AHRI shipments data also include steel boilers. For gas-fired hot water boilers, DOE assumed that steel gas-fired hot water boilers are a small fraction of shipments (approximately 0.1 percent based on 1993 shipments data, assuming that all boilers with an output capacity less than 300 kBtu/h were residential boilers).[6] For oil-fired hot water boilers, DOE calculated the steel oil-fired hot water boiler shipments from 1960 to 2002 by subtracting the calculated cast-iron oil-fired boiler shipments from the total oil-fired boiler shipments, assuming that residential shipments account for 94 percent of total shipments based on 1993 shipments data.[6] AHRI provided steel oil-fired hot water boiler data from 2003 to 2009.[3] DOE used AHRI's 2003 to 2009 data to create a linear trend to estimate the shipments from 2010 to 2012.

The *Appliance Magazine* and AHRI shipments data do not include coil and tube type gas-fired hot water boilers and high efficiency (condensing) hot water boiler shipments. From 2003 to 2012, DOE used shipments data provided by AHRI for coil and tube type gas-fired hot water boilers. For previous years, DOE assumed a 7.2 percent fraction of coil and tube type gas-fired hot water boilers to total shipments based on the AHRI's data from 2003 to 2007.[6] From 2005 to 2012, DOE used shipments data provided by AHRI for condensing hot water gas-fired boilers. For all other years,[i] DOE estimated the number of condensing hot water gas-fired and oil-fired

[i] This includes 2005 to 2012 for oil-fired boilers.

boilers shipments based on historical fraction of condensing gas-fired hot water boilers and condensing oil-fired hot water boilers described in appendix 7B.

9A.2.2.3 Accounting for Non-AHRI Manufacturer Shipments

To account for the fraction of shipments from non-AHRI member companies, DOE applied an adjustment factor to the historical shipments. This adjustment factor was developed by comparing model information from 2015 California Energy Commission (CEC),[8] Natural Resources Canada (NRCan),[9] and ENERGY STAR[10] directories to information on models reported in the AHRI directory.[11] Based on 2015 data, DOE estimated that 13.1 percent of gas-fired hot water boiler shipments are from non-AHRI member companies and 20.2 percent of oil-fired hot water boiler shipments are from non-AHRI member companies. DOE assumed that this fraction has been increasing over time from 0 percent in 1980 to the fractions above in 2013. For further details about the reduced set of models DOE used, see appendix 7D.

9A.2.3 Determination of Historical Shipments of Electric Boilers

DOE had limited historical shipments data for electric boilers. Based on AHRI-reported shipments from 1974 to 1996, electric boiler shipments decreased from 3,654 in 1974 to 253 in 1996.[12] This represented less than one percent of total shipments during the same period. In contrast, the number of electric boiler installations in the housing stock has remained fairly constant and is much greater than 1 percent of the total boiler installations in the housing stock. Therefore, DOE used the calculated fraction of electric boilers to total boilers in the housing stock based derived from RECS 2009 and CBECS 2003 data[4,5] to estimate electric boiler shipments. DOE estimated that electric boilers account for 5 percent of the total gas-fired, oil-fired and electric boilers (see Table 9A.3.1). See appendix 7A for further details regarding the building sample developed from RECS 2009 and CBECS 2003 data.

To disaggregate between electric hot water and steam boilers, DOE assumed that the fraction between electric hot water and steam boilers was equal to the fraction between gas-fired hot water and steam boilers.

9A.2.4 Summary of Historical Data by Product Class

The adjusted historical shipments by product classes are shown in Figure 9A.2.4. As shown in Figure 9A.2.4, gas-fired hot water boilers and oil-fired hot water boilers account for the majority of the residential boilers. Gas-fired steam boilers and oil-fired steam boilers also account for a significant fraction of residential boiler shipments, while the electric boilers only account for a small fraction of residential boilers.

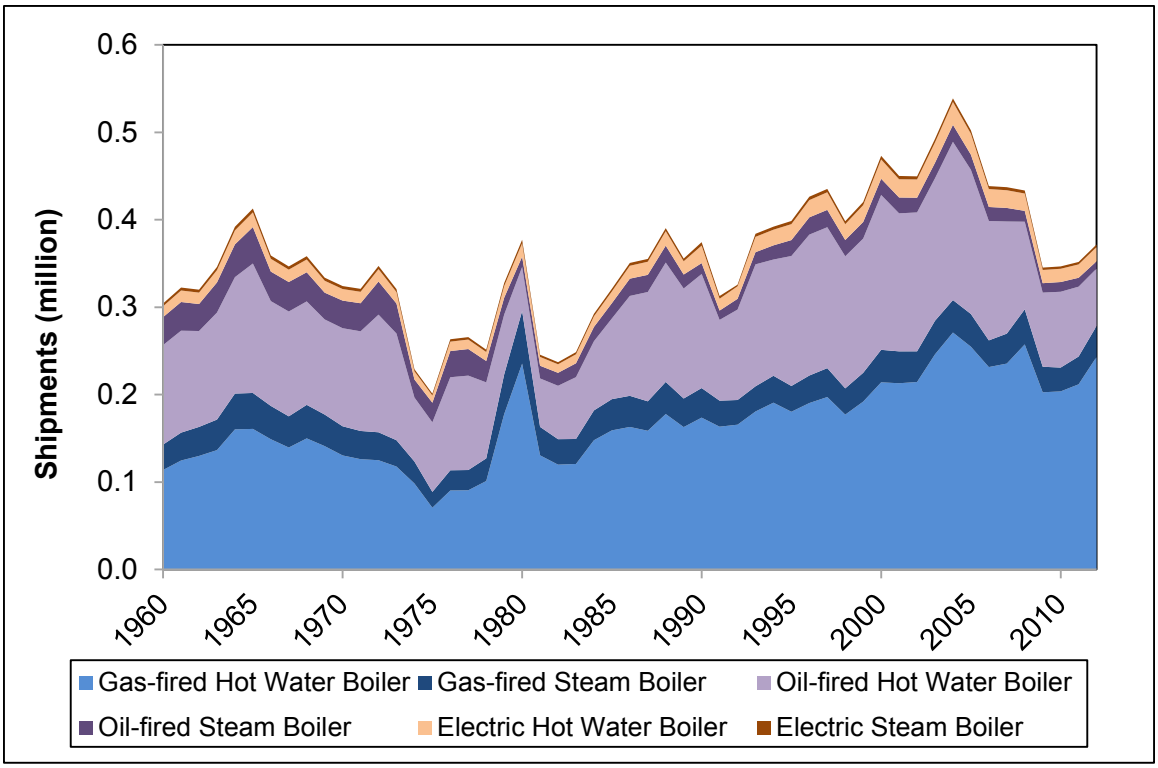

Figure 9A.2.4 Historical Shipments of Residential Boilers, 1960-2012

9A.3 FRACTION OF RESIDENTIAL BOILERS SHIPPED TO COMMERCIAL BUILDINGS

DOE derived residential boiler shipments by building type from RECS 2009 and CBECS 2003 data. DOE assumed that boilers in residential buildings and commercial buildings that are smaller than 10,000 sq. ft. are residential boilers and that half of buildings between 10,000 and 20,000 sq. ft. use a residential boiler. In addition, DOE adjusted the weights of residential buildings with a shared boiler and it assumed that commercial buildings over 5,000 sq. ft. use two or more boilers. In order to match the RECS 2009 and CBECS 2003 weights year, the CBECS 2003 weights where increased by 1.09 using the total historical commercial square footage data from 2003 compared to 2009. Table 9A.3.1 shows the resulting stock calculations.

Table 9A.3.1 Residential Boilers Stock Calculation of Gas-fired, Oil-fired, and Electric Boilers in RECS 2009 and CBECS 2003 to Determine Fraction Installed in Commercial Applications

Year	Stock of Gas-fired Boilers	Stock of Oil-fired Boilers	Stock of Electric Boilers
RECS 2009	4,873,048	3,045,143	314,176
CBECS 2003*	384,748	153,283	142,827
Commercial Fraction	7.3%	4.8%	31.3%

* Adjusted to account for buildings weights in 2009 using historic total commercial square footage.

As shown in Table 9A.3.1, based on these assumptions on RECS 2009 and CBECS 2003 data, DOE estimated that residential boilers shipped to commercial buildings accounted for 7 percent of the total historical shipments of residential gas boilers, 5 percent of residential oil boilers, and 31 percent of residential electric boilers. See appendix 7A for further details regarding from the building sample developed from RECS 2009 and CBECS 2003 data.

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CHAPTER 10. NATIONAL IMPACT ANALYSES

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CHAPTER 10. NATIONAL IMPACT ANALYSES

10.1 INTRODUCTION

This chapter describes the method the U.S. Department of Energy (DOE) used to estimate the national impacts of each trial standard level (TSL) considered for residential boilers. For each TSL, DOE evaluated the following impacts: (1) national energy savings (NES) attributable to each potential standard level; (2) monetary value of the lifetime energy savings to commercial consumers of residential boilers; (3) increased total installed costs; and (4) the net present value (NPV) of the difference between the value of operating cost savings and increased total installed costs.

The calculations were performed using a Microsoft Excel spreadsheet model, which is accessible on the Internet (www1.eere.energy.gov/buildings/appliance_standards/rulemaking.aspx?ruleid=112). The spreadsheet model, termed the National Impact Analysis (NIA) model, calculates energy savings and NPV for the nation. Details regarding and instructions for using the NIA model are provided in appendix 10A.

To calculate the annual NES, DOE first estimated the lifetime primary and fuel-fuel-cycle[a] (FFC) energy consumption at the unit level and for each year in the analysis period. The unit's lifetime primary and FFC energy consumptions were then scaled up to the national level based on the annual shipments projection and according to two scenarios: the *no-new-standards case* scenario, with no changes in the existing energy efficiency standards; and (b) the *standards case* scenario, where energy efficiency standards are set at the energy efficiency level corresponding to one of the TSLs.

DOE followed a similar procedure to calculate the annual national operating cost savings (including energy, repair, and maintenance cost savings) and the annual national incremental installed costs. DOE first estimated the lifetime operating cost and incremental installed cost at the unit level and for each year in the analysis period. The unit lifetime operating costs and incremental installed cost, estimated for units shipped in each year in the analysis period, were then scaled up to the national level based on the annual shipments projection and for the *no-new-standards case* and *standards case* scenarios described previously. DOE then calculated the difference between the aggregated national operating cost savings and national incremental installed costs to obtain the NPV of each TSL.

The NIA model incorporates the shipments model that DOE used to project future purchases of residential boilers. Chapter 9 includes an analysis of consumers' sensitivities to

[a] The full-fuel-cycle energy consumption adds to the primary energy consumption the energy consumed by the energy supply chain upstream to power plants.

total installed cost, operating expense, and income (otherwise known as elasticities), and how DOE captured those elasticities within the NIA model.

The two models used in the NIA—the NES model and the NPV model—are described more fully in subsequent sections. Table 10.1.1 summarizes the inputs and methods DOE used for the NIA analysis for the final rule. The descriptions include overviews of how DOE performed each model's calculations and summaries of the major inputs. After the technical model descriptions, this chapter presents the results of the NIA calculations.

Table 10.1.1 Summary of Inputs and Methods for the Final Rule National Impact Analysis

Inputs	**Method**
Shipments	Annual shipments from shipments model.
Compliance Date of Standard	2021.
Efficiency Trends	Based on historical trends of shipments by efficiency and updated ENERGY STAR criteria.
Annual Energy Consumption per Unit	Annual weighted-average values are a function of energy use at each TSL.
Total Installed Cost per Unit	Annual weighted-average values are a function of cost at each TSL. Projects constant future product prices based on historical data.
Annual Energy Cost per Unit	Annual weighted-average values as a function of the annual energy consumption per unit and energy prices.
Rebound Effect	Applied a rebound effect value dependent on application and sector.
Repair and Maintenance Cost per Unit	Annual values do not change with efficiency level.
Energy Prices	*AEO 2015* forecasts (to 2040) and extrapolation through 2050.
Energy Site-to-Primary and FFC Conversion	Time-series conversion factor based on *AEO 2015*.
Discount Rate	Three and seven percent.
Present Year	2015.

10.2 TRIAL STANDARD LEVELS

DOE developed trial standard levels (TSLs) that combine efficiency levels for each residential boiler product class. Table 10.2.1 presents the efficiency levels (EL) and Table 10.2.2 presents the AFUE for each product class in each TSL. The criteria used to develop trial standard levels for residential boilers rulemaking match the following:

- TSL 1: Most common efficiency levels in the current market.

- TSL 2: Intermediate efficiency levels.
- TSL 3: Efficiency levels that provide the highest NPV using a 7-percent discount rate, and that also result in a higher percentage of consumers that receive an LCC benefit than experience an LCC loss.
- TSL 4: Efficiency levels that provide the maximum NES with an NPV greater than zero at a 7-percent discount rate.
- TSL 5: Max-tech efficiency levels.

Table 10.2.1 Trial Standard Levels for AFUE Standards (Efficiency Level)

Product Class	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
Gas-fired Hot Water Boiler	1	1	2	4	6
Gas-fired Steam Boiler	1	1	1	1	2
Oil-fired Hot Water Boiler	1	2	2	3	3
Oil-fired Steam Boiler	1	1	2	3	3

Table 10.2.2 Trial Standard Levels for AFUE Standards (AFUE, %)

Product Class	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
Gas-fired Hot Water Boiler	83	83	84	90	96
Gas-fired Steam Boiler	82	82	82	82	83
Oil-fired Hot Water Boiler	85	86	86	91	91
Oil-fired Steam Boiler	84	84	85	86	86

Table 10.2.3 presents the TSLs and the corresponding product class efficiency levels (by efficiency level) that DOE considered for boiler standby mode and off mode power consumption. Table 10.2.4 presents the TSLs and the corresponding product class efficiency levels (expressed in watts) that DOE considered for boiler standby mode and off mode power consumption.

Table 10.2.3 Trial Standard Levels for Standby Mode and Off Mode Standards (Efficiency Level)

Product Class	TSL 1	TSL 2	TSL 3
Gas-fired Hot Water Boiler	1	2	3
Gas-fired Steam Boiler	1	2	3
Oil-fired Hot Water Boiler	1	2	3
Oil-fired Steam Boiler	1	2	3
Electric Hot Water Boiler	1	2	3
Electric Steam Boiler	1	2	3

Table 10.2.4 Standby Mode and Off Mode Trial Standard Levels for Residential Boilers (Power, Watts)

Product Class	TSL 1	TSL 2	TSL 3
Gas-fired Hot Water Boiler	10.0	9.7	9.0
Gas-fired Steam Boiler	9.0	8.7	8.0
Oil-fired Hot Water Boiler	12.0	11.7	11.0
Oil-fired Steam Boiler	12.0	11.7	11.0
Electric Hot Water Boiler	9.0	8.7	8.0
Electric Steam Boiler	9.0	8.7	8.0

10.3 PROJECTED EFFICIENCY TRENDS

A key component of the NIA is the energy efficiency of boilers projected over time for the no-new-standards case (without new or amended standards) and for each of the standards cases (with potential new standards).

10.3.1 No-New-Standards and Standards Case Efficiencies in 2021

For each residential boiler product class, DOE developed a distribution of efficiencies in the no-new-standards case for 2021 (the assumed compliance date for new standards), as described in chapter 8. In each standards case, DOE assumed a "roll-up" scenario to establish the efficiency distribution for 2021. Product efficiencies in the no-new-standards case that did not meet the standard under consideration would "roll up" to meet the new standard level. All efficiency shares in the no-new-standards case that were above the standard under consideration would not be affected. Table 10.3.1 and Table 10.3.2 present the efficiency distributions in 2021 by product class no-new-standards case and standards cases for residential boilers for AFUE standards and standby mode and off mode standards, respectively.

Table 10.3.1 Efficiency Distributions for the No-New-Standards and Standards Cases in 2021 for AFUE Standards

Efficiency Level		Market Share (percent)					
		No-New-Standards Case	Trial Standard Level				
			1	2	3	4	5
Gas-Fired Hot Water Boiler							
0	82% AFUE - Baseline	22.8					
1	83% AFUE - Increased HX Area	7.6	30.4	30.4			
2	84% AFUE - Increased HX Area	11.3	11.3	11.3	41.7		
3	85% AFUE - Increased HX Area	4.6	4.6	4.6	4.6		
4	90% AFUE - Condensing Baseline	11.2	11.2	11.2	11.2	57.5	
5	92% AFUE - Increased HX Area	41.3	41.3	41.3	41.3	41.3	
6	96% AFUE - Max Tech	1.2	1.2	1.2	1.2	1.2	100.0
Gas-Fired Steam Boiler							
0	80% AFUE - Baseline	16.8					
1	82% AFUE - Increased HX Area	71.6	88.4	88.4	88.4	88.4	
2	83% AFUE - Max Tech	11.6	11.6	11.6	11.6	11.6	100.0
Oil-fired Hot Water Boiler							
0	84% AFUE - Baseline	44.2					
1	85% AFUE - Increased HX Area	18.5	62.7				
2	86% AFUE - Increased HX Area	33.4	33.4	96.1	96.1		
3	91% AFUE - Condensing (Max Tech)	3.9	3.9	3.9	3.9	100.0	100.0
Oil-fired Steam Boiler							
0	82% AFUE - Baseline	44.9					
1	84% AFUE - Increased HX Area	28.7	73.6	73.6			
2	85% AFUE - Increased HX Area	18.9	18.9	18.9	92.4		
3	86% AFUE - Max Tech	7.6	7.6	7.6	7.6	100.0	100.0

Table 10.3.2 Efficiency Distributions for the No-New-Standards and Standards Cases in 2021 for Standby Mode and Off Mode Standards

Efficiency Level		Market Share (percent)			
		No-New-Standards Case	Trial Standard Level		
			1	2	3
Gas-Fired Hot Water Boiler					
0	15 Watts - Baseline	3.0			
1	13.5 Watts - Linear PS, Toroidal Xfmr	3.0	6.0		
2	13.2 Watts - Switch Mode PS	3.0	3.0	9.0	
3	12.5 Watts - SMPS, Toroidal Xfmr	91.0	91.0	91.0	100.0
Gas-Fired Steam Boiler					
0	12 Watts - Baseline	1.0			
1	10.5 Watts - Linear PS, Toroidal Xfmr	1.0	2.0		
2	10.2 Watts - Switch Mode PS	1.0	1.0	3.0	
3	9.5 Watts - SMPS, Toroidal Xfmr	97.0	97.0	97.0	100.0
Oil-fired Hot Water Boiler					
0	15 Watts - Baseline	3.0			
1	13.5 Watts - Linear PS, Toroidal Xfmr	3.0	6.0		
2	13.2 Watts - Switch Mode PS	3.0	3.0	9.0	
3	12.5 Watts - SMPS, Toroidal Xfmr	91.0	91.0	91.0	100.0
Oil-fired Steam Boiler					
0	15 Watts - Baseline	1.0			
1	13.5 Watts - Linear PS, Toroidal Xfmr	1.0	2.0		
2	13.2 Watts - Switch Mode PS	1.0	1.0	3.0	
3	12.5 Watts - SMPS, Toroidal Xfmr	97.0	97.0	97.0	100.0
Electric Hot Water Boiler					
0	12 Watts - Baseline	1.0			
1	10.5 Watts - Linear PS, Toroidal Xfmr	1.0	2.0		
2	10.2 Watts - Switch Mode PS	1.0	1.0	3.0	
3	9.5 Watts - SMPS, Toroidal Xfmr	97.0	97.0	97.0	100.0
Electric Steam Boiler					
0	12 Watts - Baseline	1.0			
1	10.5 Watts - Linear PS, Toroidal Xfmr	1.0	2.0		
2	10.2 Watts - Switch Mode PS	1.0	1.0	3.0	
3	9.5 Watts - SMPS, Toroidal Xfmr	97.0	97.0	97.0	100.0

10.3.2 Projected Efficiency Trends After 2021

No-New-Standards Case

In the absence of amended AFUE standards, the implementation of ENERGY STAR®'s new performance criteria will gradually increase the market shares of condensing gas-fired and condensing oil-fired hot water boilers. To project base-case efficiency over the 30-year shipments period, DOE extrapolated the historical trends in efficiency that were described in appendix 8H. DOE estimated that the overall market share of condensing products would grow from 54 percent in 2021 to 74 percent in 2050 for gas-fired hot water residential boilers and from 4 percent in 2021 to 8 percent by 2050 for oil-fired hot water residential boilers. The shares of the condensing ELs (EL 4, EL 5 and EL 6 for gas-fired hot water boilers) and the non-condensing ELs are kept in the same proportional relationship as in 2021. Figure 10.3.1 and Figure 10.3.2 show the assumed no-new-standards case market shares of gas-fired and oil-fired hot water boilers at each EL throughout the analysis period (2021-2050). Figure 10.3.3 and Figure 10.3.4 show the assumed no-new-standards case market shares of condensing gas-fired and oil-fired hot water boilers. More details are available in appendix 8H.

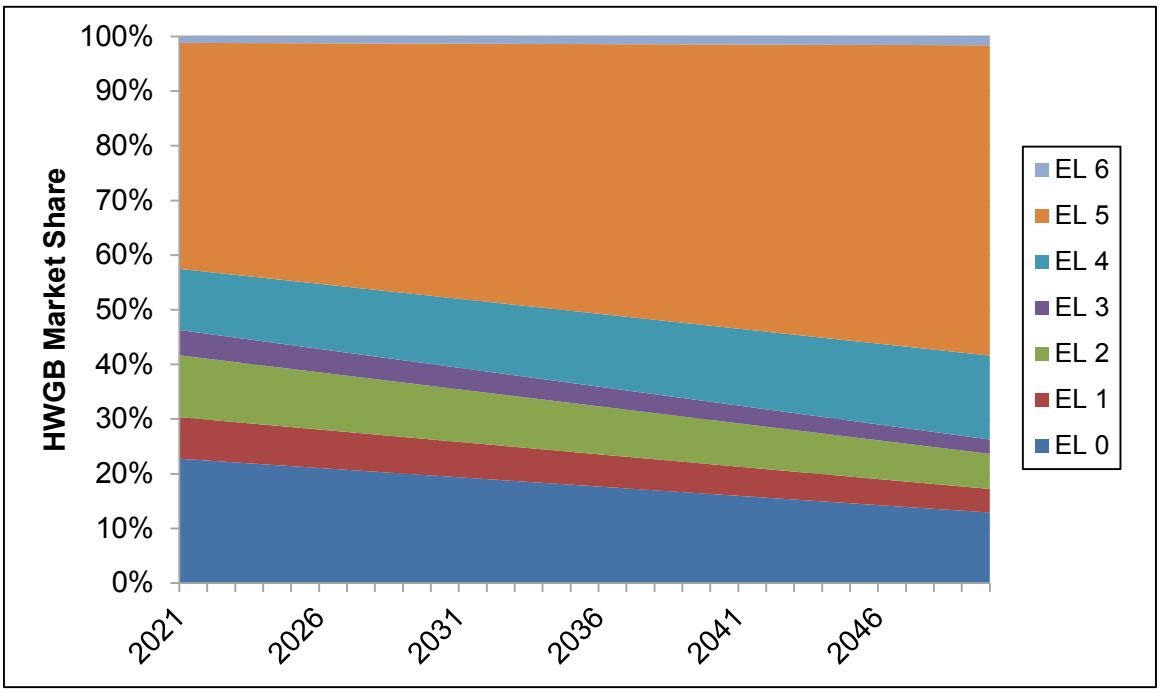

Figure 10.3.1 Projection of No-New-Standards Case Efficiency Distribution for Gas-Fired Hot Water Residential Boilers, 2021-2050

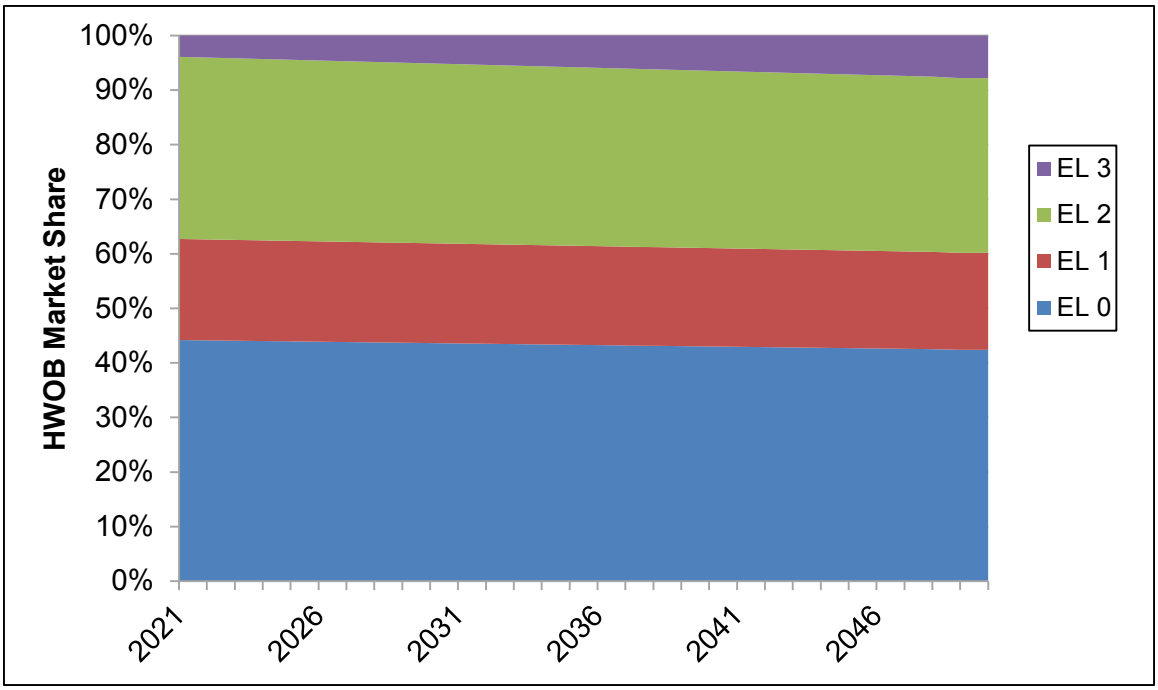

Figure 10.3.2 Projection of No-New-Standards Case Efficiency Distribution for Oil-fired Hot Water Residential Boilers, 2021-2050

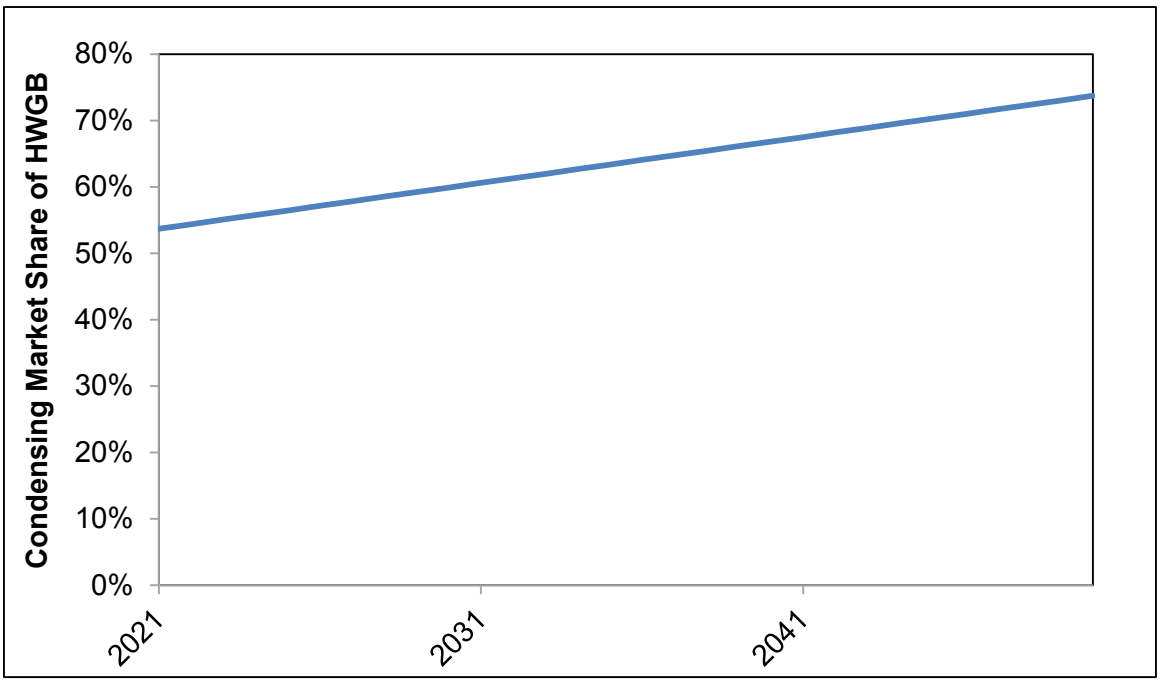

Figure 10.3.3 Projection of No-New-Standards Case Market Share for Condensing Gas-Fired Hot Water Residential Boilers

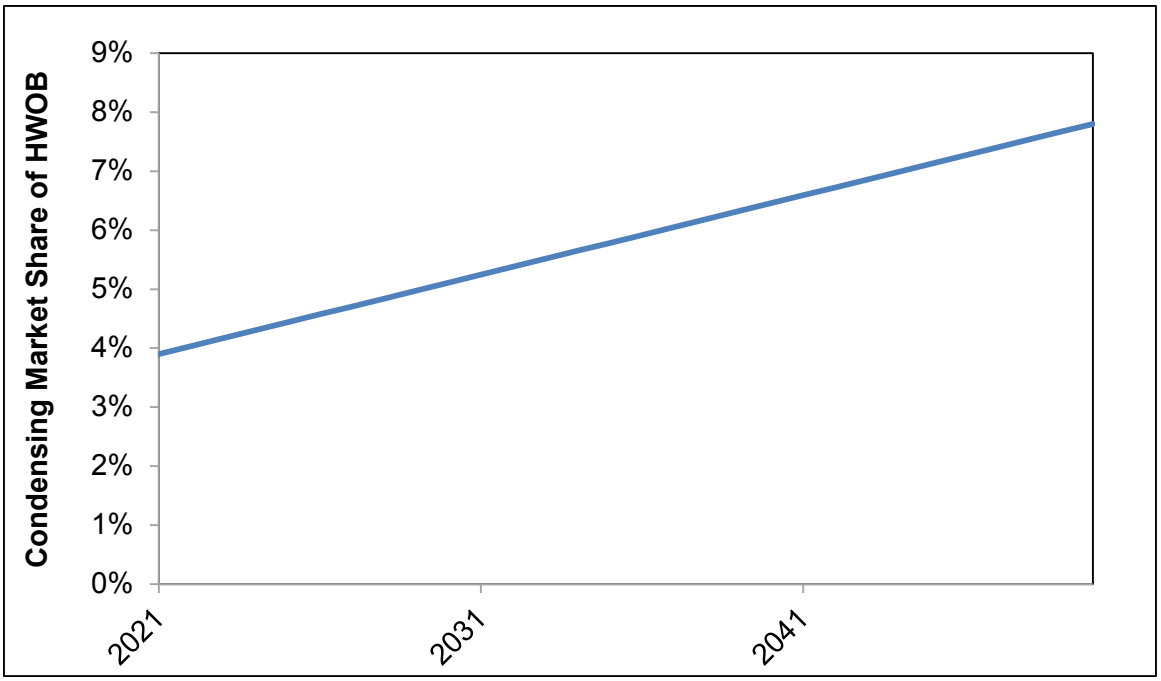

Figure 10.3.4 Projection of No-New-Standards Case Market Share for Condensing Oil-fired Hot Water Residential Boilers

DOE estimated that the market shares of condensing gas-fired and condensing oil-fired steam boilers will be negligible and that the no-new-standards case market shares by EL for gas-fired and oil-fired steam boilers remain constant over the period of analysis (*i.e.*, the market shares will remain the same as the 2021 market shares shown in Table 10.3.1).

For standby mode and off mode analysis, DOE estimated that the no-new-standards case market shares by EL would remain constant over the period of analysis for all product classes (*i.e.*, the market shares will remain the same as the 2021 market shares shown in Table 10.3.2).

Standards Cases

After the year of compliance, DOE applied the condensing boiler market share trend shown in Figure 10.3.3 and Figure 10.3.4 for the gas-fired and oil-fired hot water boilers AFUE standards cases. DOE estimated that the market shares of condensing gas-fired and condensing oil-fired steam boilers will be negligible. The difference between these standards cases and the no-new-standards case is in the market shares of the various non-condensing boiler designs as shown in Table 10.3.1. Similar to the no-new-standards case, the standards case market shares of the specific non-condensing boiler designs decrease as the condensing boiler market share increases over time.

For standby mode and off mode analysis, DOE estimated that the standards case market shares by EL would remain constant over the period of analysis for all product classes (*i.e.*, the market shares will remain the same as the 2021 market shares shown in Table 10.3.2).

10.4 NATIONAL ENERGY SAVINGS

This section describes DOE's calculation of NES for residential boilers under the considered TSLs.

10.4.1 National Energy Savings

DOE calculates annual NES as the difference between two projections: a no-new-standards case (without amended standards) and a standards case (with amended standards). The calculation of annual national energy savings in a given projection year (NES_y) are represented by the following expression:

$$NES_y = AEC_{natl-base,y} - AEC_{natl-std,y}$$

Eq. 10.1

Where:

$AEC_{natl\text{-}base,y}$ = annual energy consumption for the Nation in the no-new-standards case in quadrillion British thermal units (quads),
$AEC_{natl\text{-}std,y}$ = annual energy consumption for the Nation in the standard case in quads, and
y = year in the forecast.

National cumulative energy savings (NES_{cum}) are the sum of the annual *NES* over the lifetime of products shipped in the analysis period. This calculation is represented by the following equation:

$$NES_{cum} = \sum NES_y$$

Eq. 10.2

DOE calculated annual energy consumption (*AEC*) by multiplying the number or stock of a given unit of equipment (by vintage) by its unit energy consumption (also by vintage). The calculation of the national and each regional *AEC* is represented by the following equation:

$$AEC = \sum STOCK_V \times UEC_V$$

Eq. 10.3

Where:

$STOCK_V$ = stock of product of vintage V that survive in the year for which DOE calculated annual energy consumption,
UEC_V = annual energy consumption per product in British thermal units (Btu) of vintage V; electricity consumption is converted from site energy to power plant energy (quads) by applying a time-dependent conversion factor, and
V = year in which the product was purchased as a new unit.

The product stock depends in part on annual shipments projections from chapter 9 for the no-new-standards case and each standards case, as well as the lifetime of the given product. Based on the building sample in the life-cycle cost (LCC) and payback period (PBP) analysis, DOE estimated that a fraction of residential boilers are shipped to commercial buildings. The national energy saving from residential boilers in the standard cases includes the saving from both residential and commercial users of residential boilers.

10.4.2 Inputs to Calculation

The inputs for calculating NES are:

- average annual energy consumption per unit (*UEC*),
- shipments,
- product stock ($STOCK_V$),
- annual energy consumption for the Nation (*AEC*), and
- power plant primary energy use factor (*src_conv*).

10.4.2.1 Annual Energy Consumption per Unit

For each product class, DOE presented the per-unit annual energy consumption as a function of product efficiency in chapter 7, Energy Use Analysis. Because the per-unit annual energy consumption is directly dependent on efficiency, DOE used the shipments-weighted energy efficiency of the no-new-standards and standards cases presented in section 10.4, along with the annual energy use data presented in chapters 7 and 8, to estimate the shipment-weighted average annual per-unit energy consumption (UEC) under the no-new-standards and standards cases.

For AFUE standards, Table 10.4.1 presents the no-new-standards case and standards case shipment-weighted annual UECs for gas-fired hot water residential boilers, gas steam residential boilers, oil-fired hot water residential boilers and oil steam residential boilers in 2021. For standby mode and off mode standards, Table 10.4.2 presents the no-new-standards case and standards case shipment-weighted annual UECs for gas-fired hot water residential boilers, gas steam residential boilers, oil-fired hot water residential boilers, oil steam residential boilers, electric hot water residential boilers, and electric steam residential boilers in 2021. The values are a weighted average of residential and commercial users of residential boilers. The tables show the energy use of higher efficiency residential boilers. Note that electricity use increases at TSL 4 and 5 for hot water boilers for AFUE standards. The values after 2021 change according to the projected efficiency trends in each case.

Table 10.4.1 Average Annual Boiler Energy Use for the No-New-Standards and Standards Cases in 2021 for AFUE Standards

Product Class	No-New-Standards Case	TSL				
		1	2	3	4	5
Gas-fired Hot Water Boiler						
Average Annual Fuel Use (MMBtu/yr)	79.2	79.0	79.0	78.6	74.7	71.0
Average Annual Elec Use (kWh/yr)	267.8	267.4	267.4	266.8	329.0	315.1
Gas-fired Steam Boiler						
Average Annual Fuel Use (MMBtu/yr)	85.5	85.1	85.1	85.1	85.1	84.2
Average Annual Elec Use (kWh/yr)	90.2	90.8	90.8	90.8	90.8	94.7
Oil-fired Hot Water Boiler						
Average Annual Fuel Use (MMBtu/yr)	83.0	82.5	81.7	81.7	77.2	77.2
Average Annual Elec Use (kWh/yr)	234.1	235.7	234.1	234.1	266.8	266.8
Oil-fired Steam Boiler						
Average Annual Fuel Use (MMBtu/yr)	85.1	84.2	84.2	83.5	82.3	82.3
Average Annual Elec Use (kWh/yr)	178.3	177.1	177.1	176.0	174.3	174.3

Table 10.4.2 Average Annual Boiler Electricity Use for the No-New-Standards and Standards Cases in 2021 for Standby Mode and Off Mode Standards, kWh per year

Product Class	No-New-Standards Case	TSL		
		1	2	3
Gas-fired Hot Water Boiler	66.2	65.9	65.7	65.3
Gas-fired Steam Boiler	60.9	60.8	60.8	60.6
Oil-fired Hot Water Boiler	86.8	86.5	86.3	85.8
Oil-fired Steam Boiler	85.2	85.1	85.0	84.9
Electric Hot Water Boiler	65.7	65.6	65.6	65.4
Electric Steam Boiler	64.5	64.3	64.3	64.1

The results in Table 10.4.1 are not adjusted for the impact of the rebound effect discussed in chapter 8. For the NIA, DOE applied a rebound effect parameter that reduces the estimated national energy savings.

To estimate a rebound effect for residential boilers, DOE took into account differences in the rebound effect associated with space heating and water heating energy use, as well as differences in the rebound for residential and commercial applications. DOE used a rebound effect value of 15 percent for the space heating component of boiler total energy use and 0

percent water heating component of boiler total energy use, based on several studies.[1,2,3,4] In addition, for residential boilers installed in commercial applications and for a fraction of residential boilers installed in residential applications where the boiler is shared with multiple housing units, DOE used a rebound effect value of 0 percent based on the fact that for these users the operation of boiler is generally matched to the indoor comfort needs of the building, regardless of the equipment efficiency. DOE is not aware of any evidence to support the notion that these customers would run more efficient equipment longer or more frequently.

The overall rebound effect varied by product class from 9 percent to 11 percent. A rebound effect of 9 percent means that 9 percent of the estimated energy savings do not materialize because of increased use of the product. For standby and off mode standards, DOE did not apply a rebound effect.

DOE also considered the effects of changes in climate and building shell efficiency on residential boilers' energy use. The climate adjustment factor is based on the forecast of heating degree days (HDD) by region from *Annual Energy Outlook 2015* (*AEO 2015*),[5] which shows a declining trend due to warmer weather. DOE applied regional weights to make the factors specific to residential and commercial users of residential boilers. Due to these adjustment factors, the energy-use-weighted energy use decreases by 14 percent from 2021 to 2050.

10.4.2.2 Shipments

DOE projected shipments for each product class under the no-new-standards case and all standards cases (see chapter 9). Several factors impact projected shipments, including total installed costs, operating cost, household income, and equipment lifetime. As noted earlier, the increased total installed cost of more-efficient products causes some consumers to forego product purchases. Consequently, shipments projected under the standards cases are lower than under the no-new-standards case. DOE believes it would be inappropriate to count energy savings that result from reduced shipments due to standards. Therefore, DOE did not calculate annual energy consumption for the no-new-standards case using the no-new-standards case shipments projection. Instead, for each comparison of a standards case with the no-new-standards case, DOE used shipments associated with that particular standards case. As a result, all of the calculated energy savings are due to higher energy efficiency in the standards case.

10.4.2.3 Product Stock

The stock of product in any given year depends on annual shipments and the lifetime of a given product class. The NIA model keeps track of the number of units shipped each year. The lifetime of a unit determines how many units shipped in previous years survive in the given year. DOE assumes that products have an increasing probability of retiring as they age. The probability of survival as a function of years since purchase is termed the survival function. Refer to chapter 8 for further details on the survival functions that DOE used in its analysis.

10.4.2.4 Annual Energy Consumption

For each product class, DOE calculated the total national site (*i.e.*, the energy consumed at the household or establishment) annual energy consumption (AEC). Annual energy consumption is the product of the AEC per unit (also termed the unit energy consumption (UEC)) and the number of units of each vintage. This method accounts for differences in UEC from year to year.

10.4.2.5 Site-to-Power Plant Energy Use Factor

DOE calculates primary energy savings (power plant consumption) from site electricity savings by applying a factor to account for losses associated with the generation, transmission, and distribution of electricity. DOE derived annual average site-to-power plant factors based on the version of the National Energy Modeling System (NEMS) that corresponds to *AEO 2015*. The factors change over time in response to projected changes in the types of power plants projected to provide electricity to the country. Figure 10.4.1 shows the site-to-power plant factors from 2021 to 2040. For years after 2040 (the last year in the AEO), DOE maintained the 2040 value.

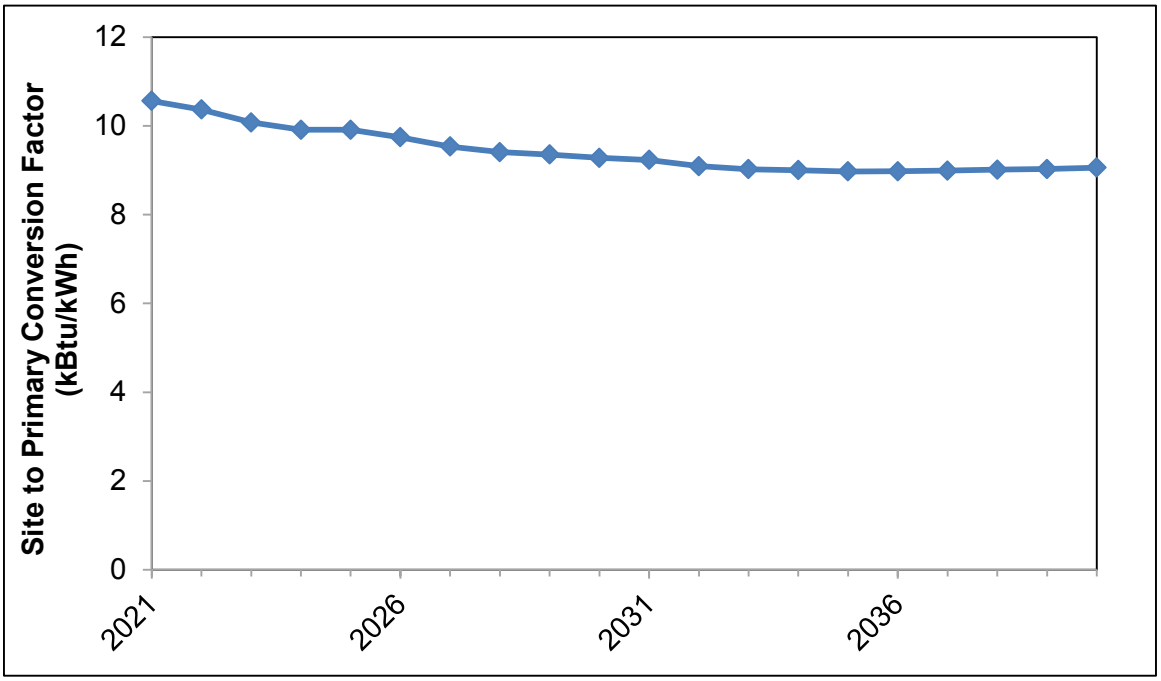

Figure 10.4.1 Primary to Site Energy Use Factor for Residential Boiler Electricity Use

10.4.2.6 Full-Fuel-Cycle Energy Factors

The full-fuel-cycle (FFC) measure includes point-of-use (site) energy; the energy losses associated with generation, transmission, and distribution of electricity; and the energy consumed "upstream" of the site in extracting, processing, and transporting or distributing

primary fuels. The FFC energy use was calculated by applying a fuel-specific FFC energy multiplier to the primary energy use. DOE developed FFC multipliers using the data and projections generated by National Energy Modeling System (NEMS) used for *AEO 2015*. The *AEO* provides extensive information about the energy system, including projections of future oil, natural gas and coal supply, energy use for oil and gas field and refinery operations, and fuel consumption and emissions related to electric power production. This information can be used to define a set of parameters representing the energy intensity of energy production. The multiplier for electricity represents the energy needed to produce and deliver the fuels that are consumed in electricity generation. The multipliers are dimensionless numbers that express the upstream energy use as a percentage of the primary energy use.

Because the FFC energy multipliers depend on the fuel type, the FFC energy is calculated starting with the annual site energy consumption (*ASEC)*. The equation is:

$$FFC(L,y) = \sum_F ASEC(L,F,y) \times h(F,y) \times \mu(F,y)$$

Eq. 10.4

Where:

$ASEC$ = annual site energy consumption,
L = trial standard level,
F = fuel type,
y = analysis year,
h = energy unit conversion factor,
μ = full fuel cycle multiplier, and
FFC = annual full fuel cycle energy consumption.

If a product uses only one fuel, then the FFC energy is equal to the primary energy *ASEC* multiplied by the FFC multiplier μ. For products that use multiple fuels, the relationship between the primary energy use and the FFC energy is less straight-forward.

As with the NES, DOE calculated cumulative, national level energy savings in the FFC metric by calculating the difference relative to the no-new-standards case and summing over the analysis period:

$$NES - FFC(L,y) = FFC(L{=}0,y) - FFC(L,y),$$

$$NES - FFC_{cum}(L) = \sum_y NES - FFC(L,y)$$

Eq. 10.5

Appendix 10B describes the method used to calculate FFC energy multipliers.

Table 10.4.3 shows the upstream energy multipliers used for residential boilers for selected years. For years after 2040 (the last year in the *AEO*), DOE maintained the 2040 value.

Table 10.4.3 Upstream Energy Multipliers (Based on *AEO 2015*)

	2021	2025	2030	2035	2040	2045	2050
Electricity	1.044	1.045	1.046	1.045	1.045	1.045	1.045
Natural Gas	1.123	1.124	1.123	1.122	1.123	1.123	1.123
Petroleum Fuels	1.171	1.169	1.165	1.165	1.165	1.165	1.165

10.5 NET PRESENT VALUE OF CONSUMER BENEFITS

10.5.1 Definition

The NPV is the value in the present of a time-series of costs and savings. The NPV is described by the equation:

$$NPV = PVS - PVC$$

Eq. 10.6

Where:

PVS = present value of savings in operating cost (including costs for energy, repair, and maintenance), and
PVC = present value of increase in total installed cost (including costs for equipment and installation).

DOE determined the *PVS* and *PVC* according to the following expressions:

$$PVS = \sum OCS_y \times DF_y$$

Eq. 10.7

$$PVC = \sum TIC_y \times DF_y$$

Eq. 10.8

Where:

OCS_y = total annual savings in operating cost each year summed over vintages of the product stock in each year *y*,
TIC_y = total annual increase in installed cost each year summed over vintages of the product stock in each year *y*,
DF_y = discount factor in each year *y*, and
y = year in the projection.

DOE calculated the total annual savings in operating cost by multiplying the number or stock of a given product (by vintage) by its per-unit operating cost savings (also by vintage). DOE calculated the total annual increase in installed cost by multiplying the number or stock of a given product (by vintage) by its per-unit total installed cost increase (also by vintage). Total annual savings in operating cost and increases in installed cost are calculated using the following equations.

$$OCS_y = \sum STOCK_V \times UOCS_V$$

Eq. 10.9

$$TIC_y = \sum STOCK_V \times UTIC_V$$

Eq. 10.10

Where:

$STOCK_V$ = stock of product of vintage V that survive in year y in the projection,
$UOCS_V$ = annual per-unit savings in operating cost of product of vintage V,
$UTIC_V$ = annual total per-unit increase in installed cost of product of vintage V, and
V = year in which the product purchased as a new unit.

As mentioned in section 10.4.1, DOE estimated that a fraction of residential boilers are shipped to commercial buildings. The net present value of consumer benefits in the standard cases includes the benefits from both residential and commercial boiler users.

DOE determined the *PVC* for each year from the compliance date of the standard (2021) through 2050. DOE determined the *PVS* for each year from the compliance date of the standard until the year when units purchased in 2021−2050 retire. DOE calculated costs ($UTIC_V$) and savings ($UOCS_V$) as the difference between each standards case and the no-new-standards case in total installed cost per unit and annual operating cost per unit, respectively.

DOE calculated a discount factor (DF_y) from the discount rate and the number of years between the "present" (2015), the year to which the sum is being discounted, and the year in which the costs and savings occur. The NPV is the sum over time of the discounted net savings.

10.5.2 Inputs to Calculation

The inputs to DOE's calculation of the NPV are:

- total installed cost per unit,
- annual per-unit savings in operation cost,
- shipments,
- product stock ($STOCK_V$),
- total annual increases in installed cost (*TIC*),
- total annual operating cost (*OCS*),

- discount factor (*DF*),
- present value of costs (*PVC*), and
- present value of savings (*PVS*).

The *total annual increase in installed cost* is equal to the annual change in the total per-unit installed cost (difference between no-new-standards case and standards case) multiplied by the shipments projected for each TSL. As with calculating energy savings, DOE did not use base-case shipments to calculate total annual installed costs for all of the product classes. DOE used the projected shipments and stock for each TSL to calculate costs.

The annual operating cost includes energy, repair, and maintenance costs. The *total annual savings in operating cost* are equal to the change in the annual operating costs (difference between no-new-standards case and standards case) per unit multiplied by the shipments projected for each candidate standard level. As with calculating total annual installed costs, DOE used standards-case shipments to calculate savings in operating cost.

10.5.2.1 Total Installed Cost per Unit

DOE described the total per-unit installed cost for each product class as a function of product efficiency in chapter 8, Life-Cycle Cost and Payback Period Analysis. Because the total per-unit annual installed cost depends directly on efficiency, DOE used the shipments-weighted efficiencies for the no-new-standards and standards cases, combined with the total installed cost presented in chapter 8, to estimate the shipments-weighted total per-unit average annual installed cost under the no-new-standards and standards cases. Table 10.5.1 shows the average installed cost of residential boilers in 2021 for the no-new-standards and standards cases for the four product classes for AFUE standards. Table 10.5.2 shows the average installed cost of residential boilers in 2021 for the no-new-standards and standards cases for the six product classes for standby mode and off mode.

For reasons discussed in chapter 8, DOE used a constant price assumption for the default projection in the NIA. To investigate the impact of different equipment price projections on the consumer net present value (NPV) for different efficiency levels, DOE also considered two alternative price trends. Details on how these alternative price trends were developed are in appendix 10C, which also presents the results of the sensitivity analysis.

Table 10.5.1 Average Installed Cost of Residential Boilers in 2021 for the No-New-Standards and Standards Cases for AFUE Standards (2014$)

Product Class	No-New-Standards Case	Trial Standard Levels				
		1	2	3	4	5
Gas-fired Hot Water Boiler	$7,006	$7,009	$7,009	$7,014	$7,394	$8,273
Gas-fired Steam Boiler	$6,392	$6,403	$6,403	$6,403	$6,403	$6,673
Oil-fired Hot Water Boiler	$8,262	$8,329	$8,425	$8,425	$10,691	$10,691
Oil-fired Steam Boiler	$8,111	$8,248	$8,248	$8,359	$8,641	$8,641

Table 10.5.2 Average Installed Cost of Residential Boilers Relative to the Baseline in 2021 for the No-New-Standards and Standards Cases for Standby Mode and Off Mode (2014$)

Product Class	No-New-Standards Case	TSL		
		1	2	3
Gas-fired Hot Water Boiler	$48.5	$48.6	$49.6	$49.7
Gas-fired Steam Boiler	$48.7	$48.8	$49.1	$49.1
Oil-fired Hot Water Boiler	$47.7	$47.8	$48.8	$48.9
Oil-fired Steam Boiler	$48.5	$48.5	$48.9	$48.9
Electric Hot Water Boiler	$47.9	$48.0	$48.3	$48.3
Electric Steam Boiler	$47.8	$47.8	$48.2	$48.2

10.5.2.2 Annual Operating Cost per Unit

The per-unit annual operating cost includes costs for energy, repair, and maintenance. DOE determined the per-unit annual savings in energy costs by multiplying the per-unit annual savings in energy consumption developed for each product class by the appropriate energy price. DOE considered operating costs separately for residential and commercial users.

Estimates of the per-unit annual energy consumption for the no-new-standards case and each standards case were presented in section 10.4.1. DOE projected the per-unit annual energy consumption for the no-new-standards case for all product classes by applying a growth trend in efficiency.

Energy prices and trends in energy prices are described in chapter 8. DOE projected energy prices based on annual changes in average residential and commercial energy prices in EIA's *AEO 2015* reference case scenario.

DOE described the total per-unit repair and maintenance costs for each product class as a function of product efficiency in chapter 8. Because the per-unit repair and maintenance costs depend directly on efficiency, DOE used the efficiencies for the no-new-standards and standards cases presented in section 10.3, combined with the repair and maintenance costs presented in chapter 8, to estimate the per-unit average repair and maintenance costs under the no-new-standards and standards cases.

Table 10.5.3 shows the average operating cost of residential boilers in 2021 for the no-new-standards and standards cases for the four product classes for AFUE standards. The operating costs change over time, depending on change in annual energy use and energy prices. Table 10.5.3 shows the average operating cost of residential boilers in 2021 for the no-new-

standards and standards cases for the six product classes for standby mode and off mode standards. The operating costs change over time, depending on change in energy prices.

Table 10.5.3 Average Annual Operating Cost of Residential Boilers in 2021 for the No-New-Standards and Standards Cases for AFUE Standards (2014$)

Product Class	No-New-Standards Case	Trial Standard Levels				
		1	2	3	4	5
Gas-fired Hot Water Boiler	$1,190	$1,186	$1,186	$1,182	$1,148	$1,097
Gas-fired Steam Boiler	$1,221	$1,217	$1,217	$1,217	$1,217	$1,206
Oil-fired Hot Water Boiler	$2,118	$2,108	$2,088	$2,088	$2,012	$2,012
Oil-fired Steam Boiler	$2,167	$2,147	$2,147	$2,129	$2,101	$2,101

Table 10.5.4 Average Annual Operating Cost of Residential Boilers in 2021 for the No-New-Standards and Standards Cases for Standby Mode and Off Mode Standards (2014$)

Product Class	No-New-Standards Case	TSL		
		1	2	3
Gas-fired Hot Water Boiler	$11.7	$11.6	$11.6	$11.5
Gas-fired Steam Boiler	$10.9	$10.9	$10.9	$10.8
Oil-fired Hot Water Boiler	$15.3	$15.3	$15.2	$15.1
Oil-fired Steam Boiler	$15.6	$15.6	$15.6	$15.6
Electric Hot Water Boiler	$7.8	$7.8	$7.8	$7.8
Electric Steam Boiler	$7.9	$7.9	$7.9	$7.9

10.5.2.3 Product Stock

The stock of product in any given year depends on annual shipments and the lifetime of a given product class. The NIA model keeps track of the number of units shipped each year. The lifetime of a unit determines how many units shipped in previous years survive in the given year. DOE assumes that products have an increasing probability of retiring as they age. The probability of survival as a function of years since purchase is termed the survival function. Refer to chapter 8 for further details on the survival functions that DOE used in its analysis.

10.5.2.4 Increases in Total Annual Installed Cost

The increase in total annual installed cost for a product under any given standards case is the product of the increase in total installed cost per unit attributable to the standard and the number of units of each vintage. This method accounts for differences in total installed cost from year to year.

10.5.2.5 Savings in Total Annual Operating Cost

The savings in total annual operating cost for any given candidate standards level is the product of the annual per-unit savings in operating cost attributable to the standard and the number of units of each vintage. This method accounts for the year-to-year differences in annual operating cost savings.

As previously discussed, DOE applied a rebound effect to adjust its estimates of energy savings. The take-back in energy consumption associated with the rebound effect provides consumers with increased value (*e.g.*, enhanced comfort associated with use of constant circulation). DOE believes that, if it were able to monetize the increased value to consumers of the rebound effect, this value would be similar in value to the foregone energy savings. Therefore, the economic impacts on consumers with or without the rebound effect are the same, so DOE did not adjust operating cost savings in the NIA.

10.5.2.6 Discount Factor

DOE multiplied monetary values in future years by a discount factor to determine the present value. The discount factor (DF) is described by the equation:

$$DF = \frac{1}{(1+r)^{(y-y_p)}}$$

Eq. 10.11

Where:
r = discount rate,
y = year of the monetary value, and
y_p = year in which the present value is being determined.

DOE estimated NPV using both a 3-percent and a 7-percent real discount rate, in accordance with the Office of Management and Budget's guidance to Federal agencies on the development of regulatory analysis, particularly section E therein: Identifying and Measuring Benefits and Costs.[6] DOE defined the present year as 2015.

10.5.2.7 Present Value of Increased Installed Cost and Savings

The present value of increased installed cost is the difference between installation cost in each standards case and the no-new-standards case discounted to the present and summed throughout the period over which DOE is considering the installation of units (from the compliance date of standards, 2021, through 2050). DOE calculated annual increases in installed cost as the difference in total installed cost for new products purchased each year, multiplied by the shipments in the standards case.

The present value of annual savings in operating cost is the difference between the no-new-standards case and each standards case discounted to the present and summed throughout

the period from the compliance date, 2021, to the time when the last unit installed in 2021−2050 is retired from service.

Savings represent decreases in operating cost (including electricity, repair, and maintenance) associated with the more energy efficient equipment purchased in each standards case compared to the no-new-standards case. Total annual savings in operating cost are the savings per unit multiplied by the number of units of each vintage that survive in a particular year.

10.6 RESULTS

10.6.1 National Energy Savings

This section provides the national energy savings that DOE calculated for each of the TSLs analyzed for residential boilers. See Table 10.6.1 for primary energy savings and Table 10.6.2 for FFC energy savings; in the case of standby mode and off mode results, see Table 10.6.3 for primary energy savings and Table 10.6.4 for FFC energy savings. DOE based the inputs to the NIA model on weighted-average values, producing results that are discrete point values, rather than a distribution of values such as is generated by the life-cycle cost and payback period analysis. The energy savings reflect application of a rebound effect.

Table 10.6.1 Primary National Energy Savings for AFUE Standards (quads)

Product Class	Trial Standard Level				
	1	2	3	4	5
Gas-fired Hot Water Boiler	0.036	0.036	0.083	0.523	1.223
Gas-fired Steam Boiler	0.005	0.005	0.005	0.005	0.016
Oil-fired Hot Water Boiler	0.015	0.045	0.045	0.136	0.136
Oil-fired Steam Boiler	0.002	0.002	0.003	0.006	0.006
Total	0.058	0.088	0.137	0.670	1.380

Table 10.6.2 Full-Fuel-Cycle National Energy Savings for AFUE Standards (quads)

Product Class	Trial Standard Levels				
	1	2	3	4	5
Gas-fired Hot Water Boiler	0.041	0.041	0.093	0.594	1.378
Gas-fired Steam Boiler	0.006	0.006	0.006	0.006	0.018
Oil-fired Hot Water Boiler	0.017	0.053	0.053	0.160	0.160
Oil-fired Steam Boiler	0.002	0.002	0.004	0.006	0.006
Total	0.066	0.101	0.156	0.766	1.563

Table 10.6.3 Primary National Energy Savings for Standby Mode and Off Mode Standards (quads)

Product Class	Trial Standard Levels		
	1	2	3
Gas-fired Hot Water Boiler	0.000688	0.000964	0.001927
Gas-fired Steam Boiler	0.000020	0.000028	0.000056
Oil-fired Hot Water Boiler	0.000155	0.000218	0.000435
Oil-fired Steam Boiler	0.000003	0.000004	0.000009
Electric Hot Water Boiler	0.000016	0.000023	0.000046
Electric Steam Boiler	0.000002	0.000003	0.000006
Total	0.000885	0.001239	0.002478

Table 10.6.4 Full-Fuel-Cycle National Energy Savings for Standby Mode and Off Mode Standards (quads)

Product Class	Trial Standard Levels		
	1	2	3
Gas-fired Hot Water Boiler	0.000719	0.001007	0.002014
Gas-fired Steam Boiler	0.000021	0.000029	0.000058
Oil-fired Hot Water Boiler	0.000162	0.000227	0.000455
Oil-fired Steam Boiler	0.000003	0.000005	0.000009
Electric Hot Water Boiler	0.000017	0.000024	0.000048
Electric Steam Boiler	0.000002	0.000003	0.000006
Total	0.000925	0.001295	0.002590

10.6.2 Net Present Value of Consumer Benefit

This section provides results of calculating the NPV for each TSL considered for residential boilers. Results, which are cumulative, are shown as the discounted dollar value of the net savings. For AFUE results, see Table 10.6.5 for NPV results with a 3-percent discount rate applied and Table 10.6.6 for 7-percent discount rate. For standby mode and off mode results, see Table 10.6.7 for 3-percent discount rate and Table 10.6.8 for 7-percent discount rate. DOE based the inputs to the NIA model on weighted-average values, yielding results that are discrete point values, rather than a distribution of values such as produced by the life-cycle cost and payback period analyses. A negative NPV indicates that the costs of a standard at a given efficiency level exceed the savings.

Table 10.6.5 Net Present Value of Consumer Benefit for AFUE Standards, Discounted at 3 Percent (billion 2014$)

Product Class	Trial Standard Levels				
	1	2	3	4	5
Gas-fired Hot Water Boiler	0.2549	0.2549	0.5862	1.3162	1.8886
Gas-fired Steam Boiler	0.0347	0.0347	0.0347	0.0347	-0.0229
Oil-fired Hot Water Boiler	0.1648	0.5462	0.5462	-1.3083	-1.3083
Oil-fired Steam Boiler	0.0166	0.0166	0.0311	0.0395	0.0395
Total	0.4710	0.8524	1.1982	0.0819	0.5969

Table 10.6.6 Net Present Value of Consumer Benefit for AFUE Standards, Discounted at 7 Percent (billion 2014$)

Product Class	Trial Standard Levels				
	1	2	3	4	5
Gas-fired Hot Water Boiler	0.0844	0.0844	0.1941	0.0040	-0.7237
Gas-fired Steam Boiler	0.0113	0.0113	0.0113	0.0113	-0.0397
Oil-fired Hot Water Boiler	0.0351	0.1387	0.1387	-1.3653	-1.3653
Oil-fired Steam Boiler	0.0029	0.0029	0.0058	0.0013	0.0013
Total	0.1338	0.2374	0.3499	-1.3486	-2.1272

Table 10.6.7 Net Present Value of Consumer Benefit for Standby Mode and Off Mode Standards, Discounted at 3 Percent (billion 2014$)

Product Class	Trial Standard Levels		
	1	2	3
Gas-fired Hot Water Boiler	0.0054	0.0028	0.0107
Gas-fired Steam Boiler	0.0002	0.0001	0.0003
Oil-fired Hot Water Boiler	0.0013	0.0007	0.0026
Oil-fired Steam Boiler	0.0000	0.0000	0.0001
Hot Water Electric Boiler	0.0001	0.0000	0.0001
Steam Electric Boiler	0.0000	0.0000	0.0000
Total	0.0070	0.0036	0.0139

Table 10.6.8 Net Present Value of Consumer Benefit for Standby Mode and Off Mode Standards, Discounted at 7 Percent (billion 2014$)

Product Class	Trial Standard Levels		
	1	2	3
Gas-fired Hot Water Boiler	0.0017	-0.00005	0.0025
Gas-fired Steam Boiler	0.0001	0.00000	0.0001
Oil-fired Hot Water Boiler	0.0005	0.00002	0.0007
Oil-fired Steam Boiler	0.0000	0.00000	0.0000
Electric Hot Water Boiler	0.0000	-0.00002	0.0000
Electric Steam Boiler	0.0000	0.00000	0.0000
Total	0.0023	-0.00005	0.0034

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APPENDIX 10A. USER INSTRUCTIONS FOR THE NATIONAL IMPACT ANALSIS SPREADSHEET MODEL

10A.1 USER INSTRUCTIONS

The results obtained in this analysis can be examined and reproduced using the Microsoft Excel® spreadsheets accessible on the Internet from the Department of Energy's (DOE's) residential boiler rulemaking page: www1.eere.energy.gov/buildings/appliance_standards/rulemaking.aspx?ruleid=112. From that page, follow the links to the final rule phase of the rulemaking and then to the analytical tools.

10A.2 STARTUP

The NIA spreadsheets enable the user to perform a National Impact Analysis (NIA) for residential boilers. To utilize the spreadsheet, the Department assumes that the user has access to a PC with a hardware configuration capable of running Windows 7 or later. To use the NIA spreadsheets, the user requires Microsoft Excel® 2010 or later installed under the Windows operating system.

10A.3 DESCRIPTION OF NATIONAL IMPACT ANALYSIS WORKSHEETS

The NIA spreadsheets perform calculations to project the change in national energy use and net present value of financial impacts due to revised energy efficiency standards. The energy use and associated costs for a given standard level are determined by calculating the shipments and then calculating the energy use and costs for all boilers shipped under that standard. The differences between the standards and base case can then be compared and the overall energy savings and net present values determined. The NIA spreadsheets consist of the following worksheets:

All Scenarios	Contains NPV, NES, and intermediate results for all equipment types, AEO economic scenarios, price trend scenarios, energy index scenarios, and discount rates. Also contains a summary pivot table of NES and NPV results by TSL for user-selected AEO economic scenario, equipment price trend scenario, energy use trend scenario, and discount rate.
Summary	Contains a summary of disaggregated NIA results for all equipment classes at the selected trial standard level (TSL).
HWGB	Contains Gas-fired Hot Water Boiler NIA calculations.
SGB	Contains Gas-fired Steam Boiler NIA calculations.
HWOB	Contains Oil-fired Hot Water Boiler NIA calculations.
SOB	Contains Oil-fired Steam Boiler NIA calculations.
HWEB	Contains Electric Hot Water Boiler NIA calculations (standby mode and off mode standards only).
SEB	Contains Electric Steam Boiler NIA calculations (standby mode and off mode standards only).

PC Inputs	Contains energy use, electricity use, retail price, installation cost, annual repair costs, and annual maintenance and repair costs for each equipment type.
Shipments	Contains historical and projected shipments data for each equipment type.
Hist Shipments	Contains historical shipments data for each equipment type. (For AFUE standards also contains repaired vs. replaced analysis)
Price Index	Contains the learning multipliers to adjust the manufacturer's cost over the entire analysis period.
Energy Indices	Contains the energy use trend multipliers to adjust for the climate conditions during the analysis period. (AFUE standards only)
Lifetime	Contains the lifetime and the retirement function for each equipment type.
Energy Factors	Contains energy conversion factors for NIA calculations.
Energy Price	Contains energy prices for each equipment type by year.
Tables	Contains labels and definitions used throughout the spreadsheet.
Eff Distribution	Contains efficiency distributions for No-New-Standards for each equipment type by year. (AFUE standards only)
Hist Shipments (AEO Reference)	Contains historical shipments calculations for each equipment type for AEO Reference scenario. (AFUE standards only)
Hist Shipments (AEO Low)	Contains historical shipments calculations for each equipment type for AEO Low Economic scenario. (AFUE standards only)
Hist Shipments (AEO High)	Contains historical shipments calculations for each equipment type for AEO Low Economic scenario. (AFUE standards only)
Supplementary Worksheets	Worksheets used for displaying outputs for documentation and downstream analysis.

10A.4 BASIC INSTRUCTIONS FOR OPERATING THE NATIONAL IMPACT ANALYSIS SPREADSHEETS

10A.4.1 Annual Fuel Utilization Efficiency Standards NIA spreadsheets

Basic instructions for operating the Annual Fuel Utilization Efficiency (AFUE) standards NIA spreadsheets are as follows:

1. Once the AFUE standards NIA spreadsheet file has been downloaded from the Department's website, open the file using MS Excel. Click "Enable Macro" when prompted and then click on the tab for the worksheet User Inputs.

2. Use MS Excel's View/Zoom commands at the top menu bar to change the size of the display to make it fit your monitor.

3. The user can change the parameters in the sheet "Summary". (Note that all the results in the "Summary" worksheet are for the selected TSL and aggregated for both

commercial and residential applications.) The default parameters (shown in Figure 10A.4.1) are:

Economic Growth	Reference
Discount Rate	7%
Analysis Period	Full
Energy Savings	FFC
Rebound	Yes
Replace/Repair	Repair
Price Trend	Constant
Energy Trend	Decr HDD
TSL	1

Figure 10A.4.1 Default User Input Parameters (Summary) for AFUE Standards NIA Spreadsheets

a) Economic Growth: Set to "Reference". To change value, click on the drop down menu next to cell "Economic Growth" and change to desired scenario ("Reference", "High", or "Low").

b) Discount Rate: Set to "7%". To change value, click on the drop down menu next to the cell "Discount Rate" and change to desired value ("7%" or "3%").

c) Analysis Period: Set to "Full". To change value, click on the drop down menu next to the cell "Analysis Period" and change to desired analysis period ("Full" (30 years) or "Short" (9 years)).

d) Energy Savings: Set to "FFC". To change value, click on the drop down menu next to the cell "Energy Savings" and change to desired value ("Site", "Primary", or "FFC").

e) Rebound: Set to "Yes". To change value, click on the drop down menu next to the cell "Rebound" and change to desired value ("Yes" or "No").

f) Replace/Repair: Set to "Repair". To change value, click on the drop down menu next to the cell "Replace/Repair" and change to desired value ("Replace" or "Repair").

g) Price Trend: Set to "Constant". To change value, click on the drop down menu next to cell "Price Trend" and change to desired scenario ("Constant", "Increasing", or "Decreasing").

h) Energy Trend: Set to "Decr HDD". To change value, click on the drop down menu next to cell "Energy Trend" and change to desired scenario ("Decr HDD" or "Constant").

i) TSL: Set to "1". To change the value, click on the drop down menu next to cell "TSL" and change to desired TSL ("1", "2", "3", "4", or "5").

4. The user can view the summarized results (NPV and NES) for the selected TSL in the "Summary" sheet (one example is shown in Figure 10A.4.2).

National		HWGB	SGB	HWOB	SOB	Total
NPV	*mi 2014$*	84.4	11.3	35.1	2.9	133.8
Incr Equipment Costs	*mi 2014$*	7.8	2.8	47.5	8.5	66.5
Operating Cost Savings	*mi 2014$*	92.2	14.1	82.6	11.4	200.3
FFC Energy Savings	*quads*	0.041	0.0058	0.0174	0.0021	0.066
Electricity	*quads*	0.00	0.00	0.00	0.00	0.000
Natural Gas	*quads*	0.04	0.01			0.046
Fuel Oil	*quads*			0.02	0.00	0.020
Perc of Non-Standards Case Consumption	%	0.00	0.00	0.00	0.01	0.3%

Residential		HWGB	SGB	HWOB	SOB	Total
NPV	*mi 2014$*	70.5	9.7	27.6	1.7	109.4
Incr Equipment Costs	*mi 2014$*	7.2	2.6	45.4	8.1	63.3
Operating Cost Savings	*mi 2014$*	77.6	12.3	73.0	9.8	172.8
FFC Energy Savings	*quads*	0.03	0.00	0.02	0.00	0.1
Electricity	*quads*	0.00	0.00	0.00	0.00	0.0
Natural Gas	*quads*	0.03	0.00			0.0
Fuel Oil	*quads*			0.02	0.00	0.0
Perc of Non-Standards Case Consumption	%	0.00	0.00	0.00	0.01	0.3%

Commercial		HWGB	SGB	HWOB	SOB	Total
NPV	*mi 2014$*	14.0	1.6	7.5	1.3	24.4
Incr Equipment Costs	*mi 2014$*	0.6	0.2	2.1	0.3	3.2
Operating Cost Savings	*mi 2014$*	14.6	1.8	9.6	1.6	27.6
FFC Energy Savings	*quads*	0.01	0.00	0.00	0.00	0.0
Electricity	*quads*	0.00	0.00	0.00	0.00	0.0
Natural Gas	*quads*	0.01	0.00			0.0
Fuel Oil	*quads*			0.00	0.00	0.0
Perc of Non-Standards Case Consumption	%	0.00	0.00	0.00	0.01	0.3%

Figure 10A.4.2 NIA Results Summary for AFUE Standards

10A.4.2 Standby Mode and Off Mode Standards NIA spreadsheets

Basic instructions for operating the standby mode and off mode standards NIA spreadsheets are as follows:

1. Once the standby mode and off mode standards NIA spreadsheet file has been downloaded from the Department's website, open the file using MS Excel. Click "Enable Macro" when prompted and then click on the tab for the worksheet User Inputs.

2. Use MS Excel's View/Zoom commands at the top menu bar to change the size of the display to make it fit your monitor.

3. The user can change the parameters in the sheet "Summary". (Note that all the results in the "Summary" worksheet are for the selected TSL and aggregated for both commercial and residential applications.) The default parameters (shown in Figure 10A.4.3) are:

Economic Growth	Reference
Discount Rate	7%
Analysis Period	Full
Energy Savings	FFC
Price Trend	Constant
TSL	1

Figure 10A.4.3 Default User Input Parameters (Summary) for Standby Mode and Off Mode NIA Spreadsheets

a) Economic Growth: Set to "Reference". To change value, click on the drop down menu next to cell "Economic Growth" and change to desired scenario ("Reference", "High", or "Low").

b) Discount Rate: Set to "7%". To change value, click on the drop down menu next to the cell "Discount Rate" and change to desired value ("7%" or "3%").

c) Analysis Period: Set to "Full". To change value, click on the drop down menu next to the cell "Analysis Period" and change to desired analysis period ("Full" (30 years) or "Short" (9 years)).

d) Energy Savings: Set to "FFC". To change value, click on the drop down menu next to the cell "Energy Savings" and change to desired value ("Site", "Primary", or "FFC").

e) Price Trend: Set to "Constant". No other options available.

f) TSL: Set to "1". To change the value, click on the drop down menu next to cell "TSL" and change to desired TSL ("1", "2", or "3").

4. The user can view the summarized results (NPV and NES) for the selected TSL in the "Summary" sheet (one example is shown in Figure 10A.4.4).

National		HWGB	SGB	HWOB	SOB	HWEB	SEB	Total
NPV	*mi 2014$*	1.7	0.1	0.5	0.0	0.0	0.0	2.3
Incr Equipment Costs	*mi 2014$*	0.3	0.0	0.1	0.0	0.0	0.0	0.4
Operating Cost Savings	*mi 2014$*	2.0	0.1	0.5	0.0	0.0	0.0	2.7
FFC Energy Savings	*quads*	0.0	0.0	0.0	0.0	0.0	0.0	0.0009
Electricity	*quads*	0.0	0.0	0.0	0.0	0.0	0.0	0.0009
Perc of BC Consumption	%	0.5%	0.2%	0.4%	0.1%	0.2%	0.2%	0.4%

Residential		HWGB	SGB	HWOB	SOB	HWEB	SEB	Total
NPV	*mi 2014$*	1.6	0.1	0.4	0.0	0.0	0.0	2.1
Incr Equipment Costs	*mi 2014$*	0.3	0.0	0.1	0.0	0.0	0.0	0.4
Operating Cost Savings	*mi 2014$*	1.9	0.1	0.5	0.0	0.0	0.0	2.5
FFC Energy Savings	*quads*	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	*quads*	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Perc of BC Consumption	%	0.5%	0.2%	0.4%	0.1%	0.2%	0.2%	0.4%

Commercial		HWGB	SGB	HWOB	SOB	HWEB	SEB	Total
NPV	*mi 2014$*	0.1	0.0	0.0	0.0	0.0	0.0	0.1
Incr Equipment Costs	*mi 2014$*	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Operating Cost Savings	*mi 2014$*	0.1	0.0	0.0	0.0	0.0	0.0	0.2
FFC Energy Savings	*quads*	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electricity	*quads*	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Perc of BC Consumption	%	0.5%	0.2%	0.4%	0.1%	0.2%	0.2%	0.4%

Figure 10A.4.4 NIA Results Summary of Standby Mode and Off Mode Standards

10A.4.3 Setting Automatic Calculation Mode for Spreadsheets

Make sure that the spreadsheet is in automatic calculation mode. The calculation mode could be changed by (shown in Figure 10A.4.5):

1. In Excel 2010 and later, go to the tab "Formulas" in the Office ribbon.
2. Click on the button "Calculation Options" and select "Automatic".

The results are automatically updated and are reported in the source energy savings matrix, net present value matrix, and summary table for each product class.

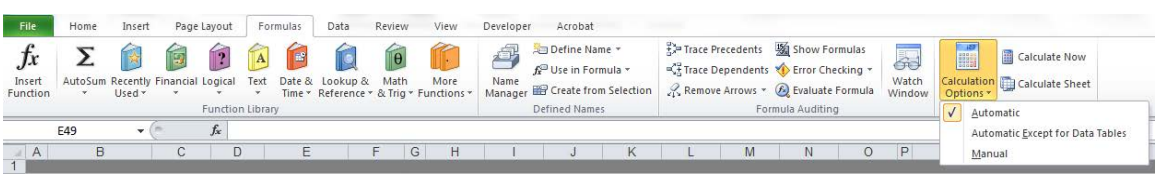

Figure 10A.4.5 Set the Spreadsheet to Automatic Calculation Mode

APPENDIX 10B. FULL-FUEL-CYCLE ANALYSIS

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APPENDIX 10B. FULL-FUEL-CYCLE ANALYSIS

10B.1 INTRODUCTION

This appendix summarizes the methods the U.S. Department of Energy (DOE) used to calculate the estimated full-fuel-cycle (FFC) energy savings from potential energy conservation standards. The FFC measure includes point-of-use (site) energy; the energy losses associated with generation, transmission, and distribution of electricity; and the energy consumed in extracting, processing, and transporting or distributing primary fuels. DOE's method of analysis previously encompassed only site energy and the energy lost through generation, transmission, and distribution of electricity. In 2011 DOE announced its intention, based on recommendations from the National Academy of Sciences, to use FFC measures of energy use and emissions when analyzing proposed energy conservation standards.[1] This appendix summarizes the methods DOE used to incorporate impacts of the full fuel cycle into the analysis.

In the national energy savings calculation, DOE estimates the site, primary and full-fuel-cycle (FFC) energy consumption for each standard level, for each year in the analysis period. DOE defines these quantities as follows:

- Site energy consumption is the physical quantity of fossil fuels or electricity consumed at the site where the end-use service is provided.[a] The site energy consumption is used to calculate the energy cost input to the NPV calculation.
- Primary energy consumption is defined by converting the site fuel use from physical units, for example cubic feet for natural gas, or kWh for electricity, to common energy units (million Btu or MMBtu). For electricity the conversion factor is a marginal heat rate that incorporates losses in generation, transmission and distribution, and depends on the sector, end use and year.
- The full-fuel-cycle (FFC) energy use is equal to the primary energy use plus the energy consumed "upstream" of the site in the extraction, processing and distribution of fuels. The FFC energy use was calculated by applying a fuel-specific FFC energy multiplier to the primary energy use.

For electricity from the grid, site energy is measured in terawatt-hours (TWh). The primary energy of a unit of grid electricity is equal to the heat content of the fuels used to generate that electricity, including transmission and distribution losses.[b] DOE typically measures the primary energy associated with the power sector in quads (quadrillion Btu). Both primary fuels and electricity are used in upstream activities. The treatment of electricity in full-fuel-cycle analysis must distinguish between electricity generated by fossil fuels and electricity generated from renewable sources (wind, solar, and hydro). For the former, the upstream fuel cycle relates

[a] For fossil fuels, this is the site of combustion of the fuel.
[b] For electricity sources like nuclear energy and renewable energy, the primary energy is calculated using the convention described below.

to the fuel consumed at the power plant. There is no upstream component for the latter, because no fuel *per se* is used.

10B.2 MARGINAL HEAT RATES

DOE uses marginal heat rates to convert site electricity savings in TWh to primary energy savings in quads. The marginal heat rates are developed as a function of the sector, end-use and year of the analysis period. For this analysis DOE uses output of the DOE/Energy Information Administration (EIA)'s National Energy Modeling System (NEMS).[2] EIA uses the NEMS model to produce the *Annual Energy Outlook* (*AEO*). DOE's approach uses the most recently available edition, in this case *AEO 2015*.[3] The *AEO* publication includes a reference case and a series of side cases incorporating different economic and policy scenarios. DOE uses these results to estimate the relationship between marginal demand reductions and the resulting generation, emissions and capacity changes. The methodology is summarized in appendix 15A of this TSD, and more detail is provided in Coughlin (2014).[4]

The calculation of marginal heat rates proceeds in three steps:

1. DOE calculates fuel-specific marginal heat rates, equal to the primary energy consumed per unit of electricity generated at the margin for each of the principal fuel types used in electricity generation (coal, natural gas, petroleum, renewables, and nuclear). These may differ from the average heat rate, equal to the total primary energy use divided by total generation for that fuel, because the technology mix for marginal plants may be different from the average for the grid. DOE follows EIA convention in assigning a constant heat rate of 10.5 Btu/Wh to nuclear power and 10.3 Btu/Wh to electricity from renewable sources. The fuel-specific heat rates for coal (cl), natural gas (ng) and petroleum fuels (pf) are shown in Figure 10B.2.1. The figure shows the marginal values as solid lines. The AEO reference case average values are shown for comparison (dashed lines).
2. For each sector and end-use, DOE calculates fuel share weights that distribute a unit of reduced demand for that end-use across the five principal fuel types.
3. DOE multiplies the fuel-share weights by the fuel specific marginal heat rates to define a marginal heat rate for the sector/end-use. The fuel-share weights are presented in appendix 15A. In equation form

$$h(u,y) = \sum_f w(u,f)\, H(f,y)$$

Where:

u = an index representing the sector/end-use (e.g. commercial cooling)
y = the analysis year
f = the fuel type
$w(u,f)$ = the fuel-share weight
$H(f,y)$ = the fuel-specific marginal heat rate plotted in Figure 10B.2.1
$h(u,y)$ = the end-use specific marginal heat rate

The sector/end-use specific marginal heat rates are shown in Table 10B.2.1. These marginal heat rates convert site electricity to primary energy in quads; i.e., the units used in the figures are quads per TWh.

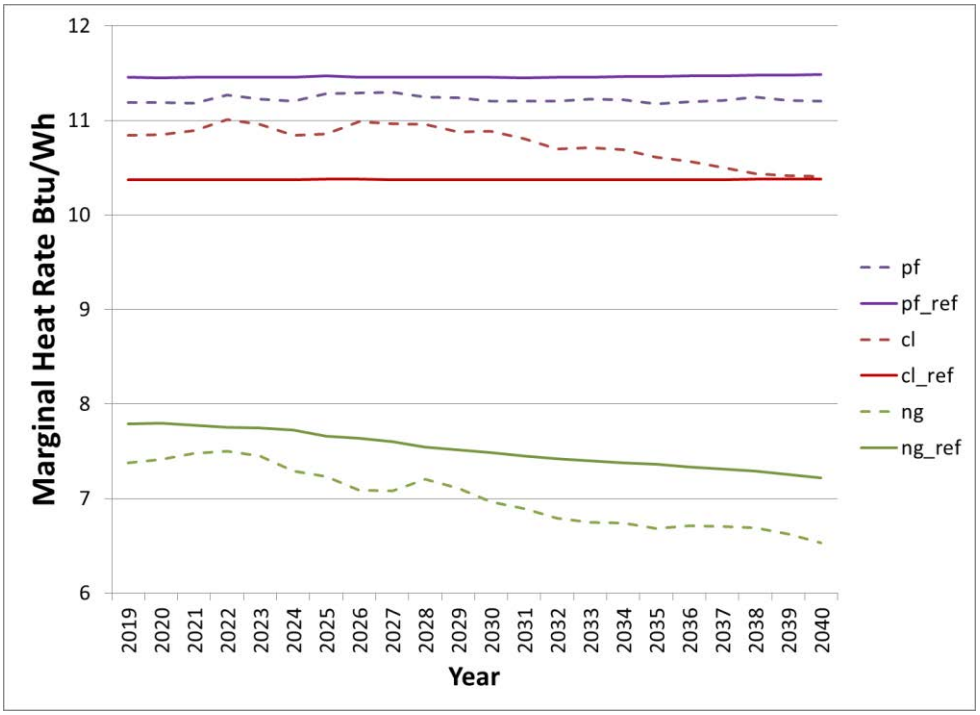

Figure 10B.2.1 Fuel Specific Marginal (Solid) and Average (Dashed) Heat Rates

Table 10B.2.1 Marginal Heat Rates (quads/TWh) by Sector and End-Use

	2020	2025	2030	2035	2040
Commercial Sector					
cooking	1.05E-02	9.77E-03	9.13E-03	8.82E-03	8.90E-03
lighting	1.05E-02	9.79E-03	9.15E-03	8.84E-03	8.92E-03
office equipment (non-pc)	1.05E-02	9.72E-03	9.07E-03	8.77E-03	8.85E-03
office equipment (pc)	1.05E-02	9.72E-03	9.07E-03	8.77E-03	8.85E-03
other uses	1.05E-02	9.74E-03	9.09E-03	8.79E-03	8.87E-03
refrigeration	1.06E-02	9.85E-03	9.21E-03	8.90E-03	8.99E-03
space cooling	1.04E-02	9.61E-03	8.96E-03	8.66E-03	8.73E-03
space heating	1.07E-02	9.92E-03	9.29E-03	8.98E-03	9.07E-03
ventilation	1.06E-02	9.85E-03	9.22E-03	8.91E-03	8.99E-03
water heating	1.05E-02	9.79E-03	9.15E-03	8.85E-03	8.93E-03
Industrial Sector					
all uses	1.05E-02	9.74E-03	9.09E-03	8.79E-03	8.87E-03
Residential Sector					
clothes dryers	1.06E-02	9.82E-03	9.18E-03	8.88E-03	8.96E-03
cooking	1.05E-02	9.80E-03	9.16E-03	8.85E-03	8.94E-03
freezers	1.06E-02	9.84E-03	9.21E-03	8.90E-03	8.98E-03
lighting	1.06E-02	9.88E-03	9.24E-03	8.94E-03	9.02E-03
other uses	1.06E-02	9.82E-03	9.18E-03	8.88E-03	8.96E-03
refrigeration	1.06E-02	9.84E-03	9.21E-03	8.90E-03	8.98E-03
space cooling	1.04E-02	9.63E-03	8.98E-03	8.68E-03	8.75E-03
space heating	1.07E-02	9.91E-03	9.28E-03	8.97E-03	9.06E-03
water heating	1.06E-02	9.84E-03	9.20E-03	8.90E-03	8.98E-03

10B.3 FFC METHODOLOGY

The methods used to calculate FFC energy use are summarized here. The mathematical approach to determining FCC is discussed in Coughlin (2012).[5] Details related to the modeling of the fuel production chain are presented in Coughlin (2013).[6]

When all energy quantities are normalized to the same units, FFC energy use can be represented as the product of the primary energy use and an FFC multiplier. Mathematically the FFC multiplier is a function of a set of parameters that represent the energy intensity and material losses at each stage of energy production. Those parameters depend only on physical data, so the calculations require no assumptions about prices or other economic factors. Although the parameter values may differ by geographic region, this analysis utilizes national averages.

The fuel cycle parameters are defined as follows.

- a_x is the quantity of fuel *x* burned per unit of electricity produced for grid electricity. The calculation of a_x includes a factor to account for losses incurred through the transmission and distribution systems.

- b_y is the amount of grid electricity used in producing fuel *y*, in MWh per physical unit of fuel *y*.
- c_{xy} is the amount of fuel *x* consumed in producing one unit of fuel *y*.
- q_x is the heat content of fuel *x* (MBtu/physical unit).

All the parameters are calculated as functions of an annual time step; hence, when evaluating the effects of potential new standards, a time series of annual values is used to estimate the FFC energy and emissions savings in each year of the analysis period and cumulatively.

The FFC multiplier is denoted μ (mu). A separate multiplier is calculated for each fuel used on site. Also calculated is a multiplier for electricity that reflects the fuel mix used in its generation. The multipliers are dimensionless numbers applied to primary energy savings to obtain the FFC energy savings. The upstream component of the energy savings is proportional to (μ-1). The fuel type is denoted by a subscript on the multiplier μ.

The method for performing the full-fuel-cycle analysis utilizes data and projections published in the *AEO 2015*.[3] Table 10B.3.1 summarizes the data used as inputs to the calculation of various parameters. The column titled "AEO Table" gives the name of the table that provided the reference data.

Table 10B.3.1 Dependence of FFC Parameters on *AEO* Inputs

Parameter(s)	Fuel(s)	*AEO* Table	Variables
q_x	All	Conversion factors	MMBtu per physical unit
a_x	All	Electricity supply, disposition, prices, and emissions Energy consumption by sector and source	Generation by fuel type Electric energy consumption by the power sector
b_c, c_{nc}, c_{pc}	Coal	Coal production by region and type	Coal production by type and sulfur content
b_p, c_{np}, c_{pp}	Petroleum	Refining industry energy consumption Liquid fuels supply and disposition International liquids supply and disposition Oil and gas supply	Refining-only energy use Crude supply by source Crude oil imports Domestic crude oil production
c_{nn}	Natural gas	Oil and gas supply Natural gas supply, disposition, and prices	U.S. dry gas production Pipeline, lease, and plant fuel
z_x	All	Electricity supply, disposition, prices, and emissions	Power sector emissions

AEO 2015 does not provide all the information needed to estimate total energy use in the fuel production chain. Coughlin (2013) describes the additional data sources needed to complete the analysis. The time dependence in the FFC multipliers, however, arises exclusively from variables taken from the *AEO*.

10B.4 ENERGY MULTIPLIERS FOR THE FULL FUEL CYCLE

FFC energy multipliers for selected years are presented in Table 10B.4.1. The 2040 value was held constant for the analysis period beyond 2040, which is the last year in the *AEO 2015* projection. The multiplier for electricity reflects the shares of various primary fuels in total electricity generation throughout the forecast period.

Table 10B.4.1 Energy Multipliers for the Full Fuel Cycle (Based on *AEO 2015*)

	2020	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
Electricity	1.044	1.045	1.046	1.045	1.045	1.045	1.045
Natural Gas	1.123	1.124	1.123	1.122	1.123	1.123	1.123
Petroleum Fuels	1.171	1.169	1.165	1.165	1.165	1.165	1.165

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APPENDIX 10C. NATIONAL NET PRESENT VALUE OF CONSUMER BENEFITS USING ALTERNATIVE PRODUCT PRICE FORECASTS

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APPENDIX 10C. NATIONAL NET PRESENT VALUE OF CONSUMER BENEFITS USING ALTERNATIVE PRODUCT PRICE FORECASTS

10C.1 INTRODUCTION

For reasons described in chapter 8, the U.S. Department of Energy (DOE) used a constant price assumption for the default projection in the national impact analysis (NIA). To investigate the impact of different product price projections on the consumer net present value (NPV) at each considered efficiency level for residential boilers, DOE considered two alternative price trends for a sensitivity analysis based on price indexes relevant to residential boilers. This appendix describes the alternative price trends and compares NPV results for these scenarios with the default price projection.[a]

10C.2 ALTERNATIVE RESIDENTIAL BOILER PRICE TREND SCENARIOS

DOE considered two alternative price trends for the sensitivity analysis. The decreasing price scenario used an exponential fit on the downward part of a deflated price index for steel heating boilers during the period of 1980 to 1998. The increasing price scenario assumed that the price of residential boilers will rise at the same annual price change percentage as was derived from the decreasing price scenario.

10C.2.1 Decreasing Price Scenario – Exponential Fit Approach

DOE examined two boiler-related producer price index (PPI) series from the Bureau of Labor Statistics (BLS): the cast iron heating boiler PPI from 1999 to 2014 and the steel heating boiler PPI, which started in 1980 but was discontinued between 1987 and 1993.[b] Figure 10C.2.1 presents the inflation-adjusted PPI trends for cast iron heating boilers and steel heating boilers (solid lines).

[a] This appendix only presents results for the active mode (AFUE standard) analysis. DOE did not apply product price trends to the standby mode and off mode analysis.
[b] Cast iron heating boiler PPI series ID: PCU 3334143334141; Steel heating boiler PPI series ID: PCU 3334143334145; www.bls.gov/ppi/

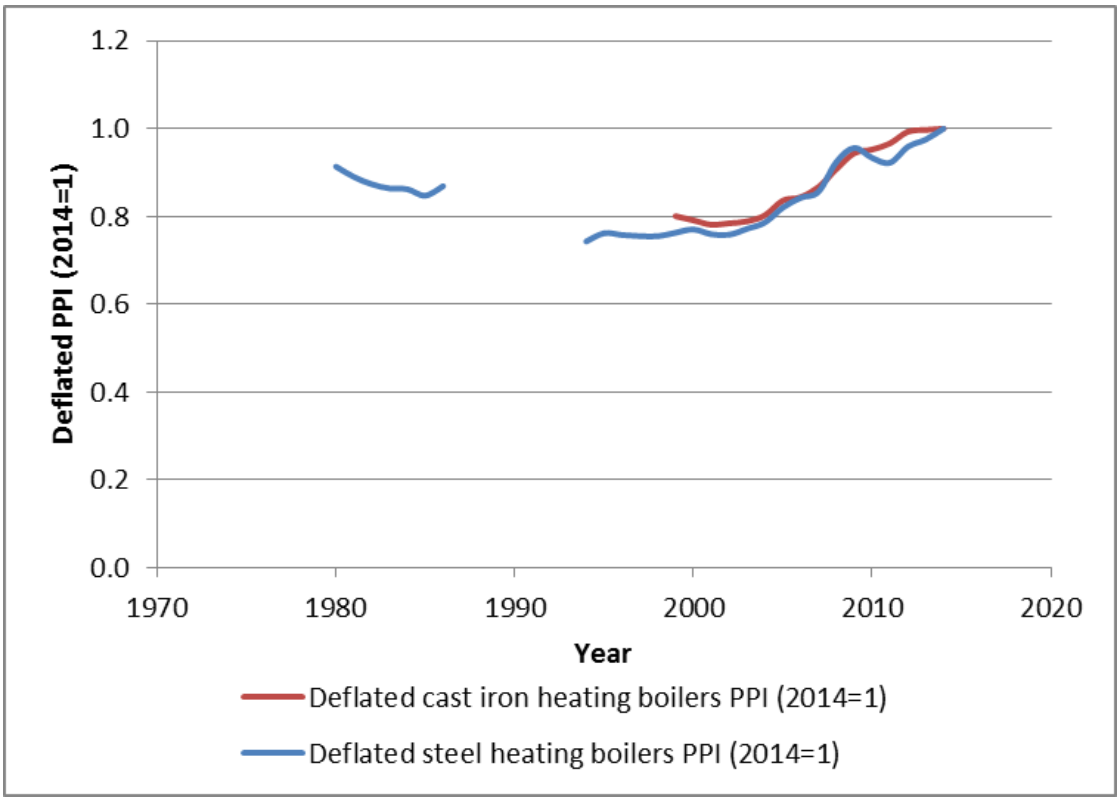

Figure 10C.2.1 Deflated Cast Iron Heating Boiler PPI from 1999 to 2014; Deflated Steel Heating Boiler PPI from 1980 to 1986 and 1994 to 2014

These two PPI series follow similar upward trends during the overlapping years. The similarity in price trends between the two products may be attributed to the use of iron ore and steel, primary materials in the production of residential boilers whose prices have also risen since the early 2000s (Figure 10C.2.2).[c]

[c] Iron and steel mills PPI series ID: PCU331110331110; www.bls.gov/ppi/

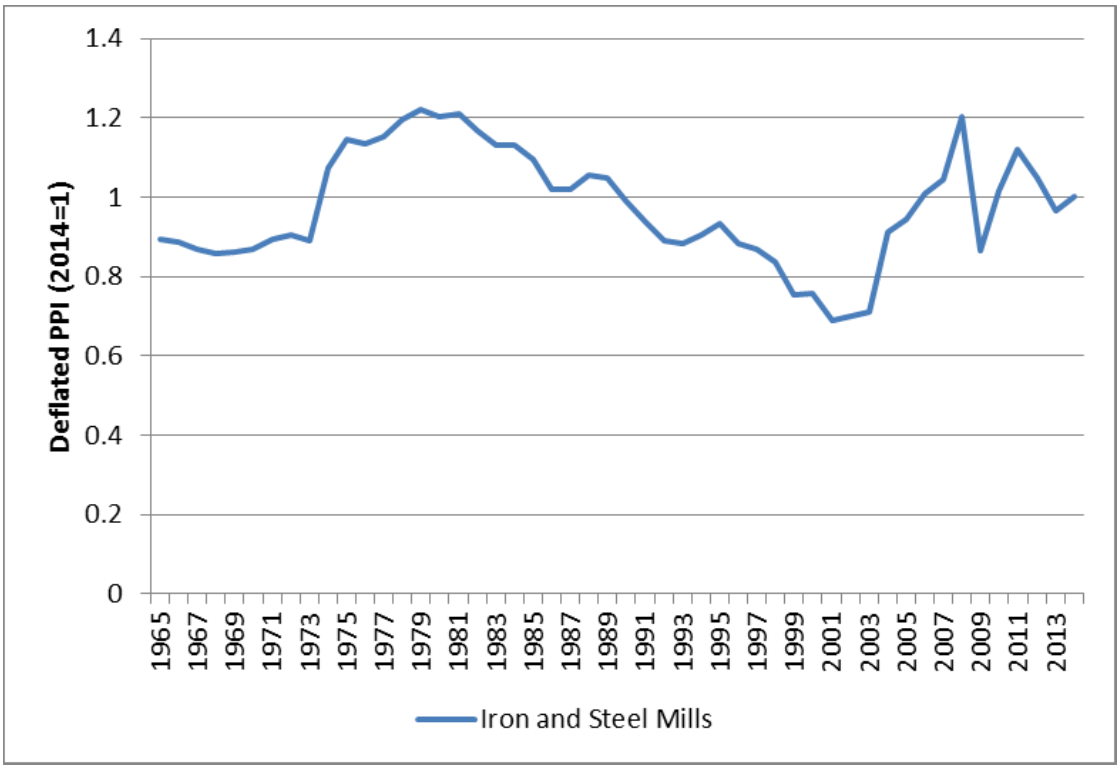

Figure 10C.2.2 Deflated Iron and Steel Mills PPI from 1965 to 2014

Because boiler PPIs are heavily driven by iron and steel prices, a downward trend, consistent with the iron and steel mills PPI is expected between 1987 and 1993 for the steel heating boilers PPI. DOE extrapolated the steel heating boiler PPI to fill the data gap by assuming a constant price decline rate, -2.01 percent, which is shown as a dotted line in the red dashed box in Figure 10C.2.3.

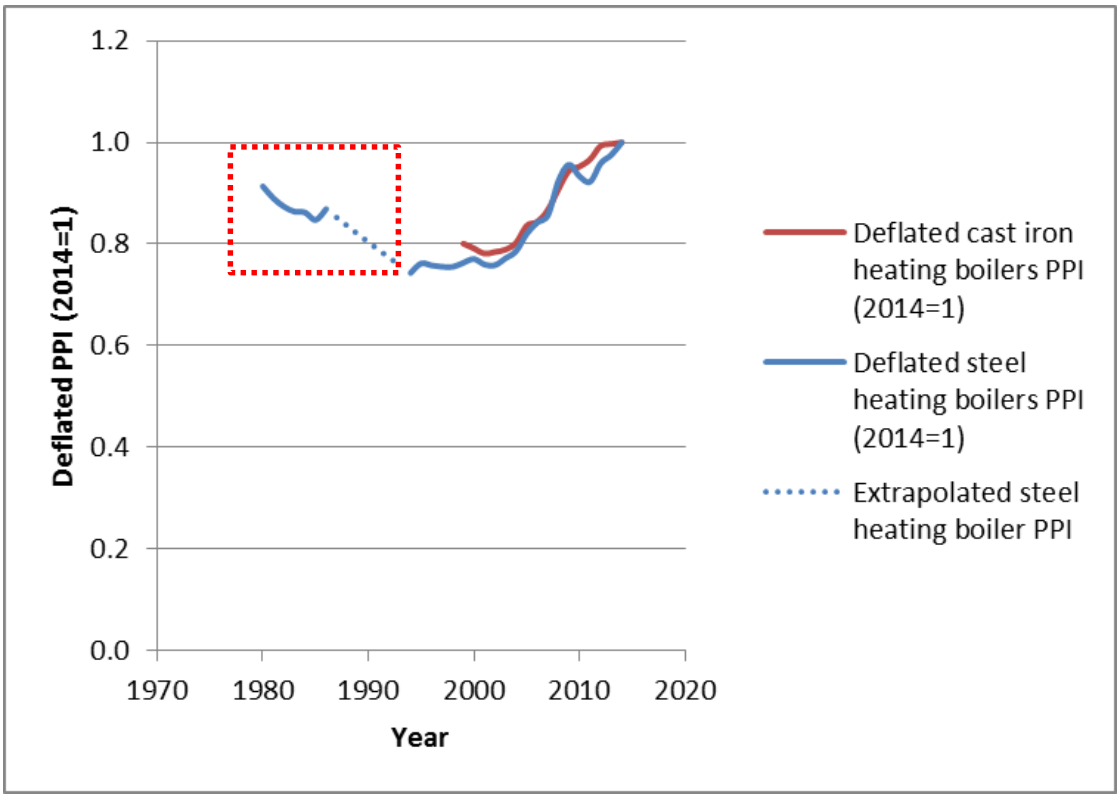

Figure 10C.2.3 Extrapolated Steel Heating Boiler PPI from 1987 to 1993

It is reasonable to conclude from the data that the historical price trend for steel heating boilers is similar to that for cast iron heating boilers, and should reflect the overall price trend for residential boilers. Therefore, although cast iron heating boilers represent the majority of residential boilers, DOE used the historical price trend for steel heating boilers to determine the decreasing price scenario because of the greater quantity of data available for steel heating boilers. For the decreasing price scenario, DOE used the inflation-adjusted steel heating boiler PPI spanning the time period from 1980-1998 to fit an exponential model with *year* as the explanatory variable. The PPI during this period of time showed a continuing downward trend, so the exponential fit based on this part of the historical PPI represents a decreasing future price projection.

The PPI data reflect nominal prices adjusted for product quality changes. An inflation-adjusted (deflated) price index for steel heating boilers was calculated by dividing the PPI series by the gross domestic product-chained Price Index. The deflated price index is presented in 2014 dollar values. In this case, the exponential function takes the form of:

$$Y = a \cdot e^{bX}$$

Eq. 10C.1

Where:

Y = steel heating boiler price index,

X = time variable,
a = constant, and
b = slope parameter of the time variable.

To estimate these exponential parameters, a least-squares fit was performed on the inflation-adjusted steel heating boiler price index versus *year* from 1980 to 1998, as shown in Figure 10C.2.4.

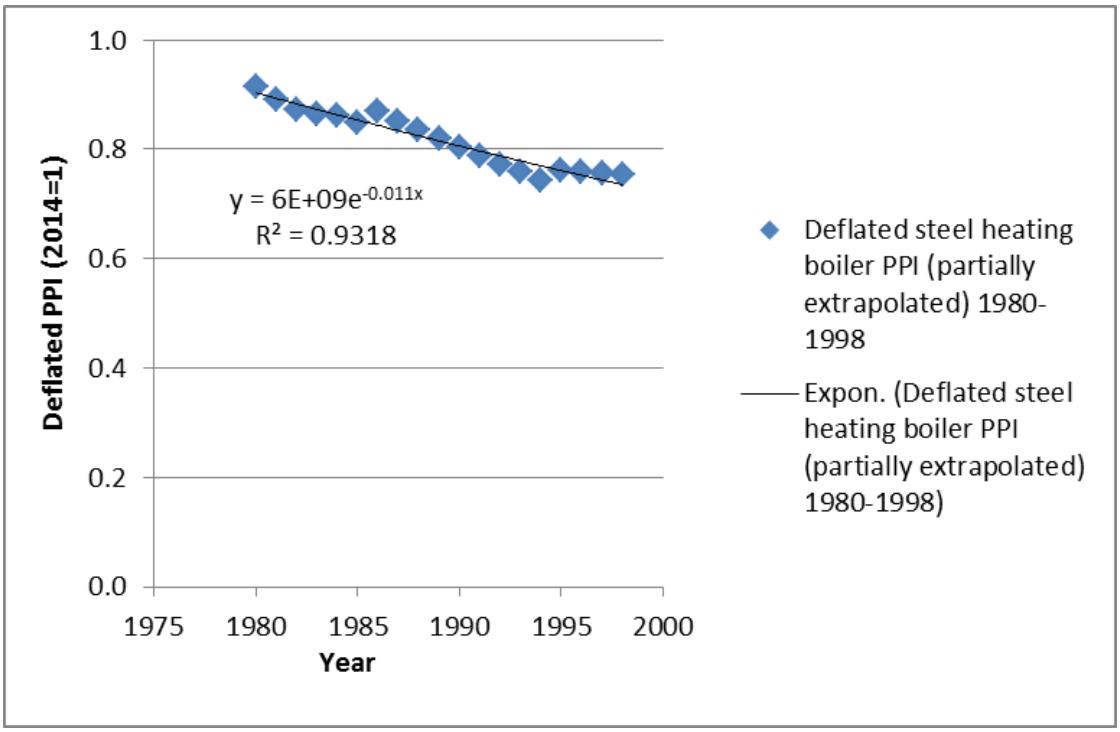

Figure 10C.2.4 Deflated Steel Heating Boiler PPI versus Year, with Exponential Fit from 1980 to 1998

The regression performed as an exponential trend line fit results in an R-square of 0.93, which indicates a close fit to the data, and yields an average price decline of 1.14 percent from the previous year. The final estimated exponential function is:

$$Y = 6.1809 \times 10^9 \cdot e^{(-0.011)X}$$

Eq. 10C.2

DOE then derived a price factor index for this scenario, renormalized with 2014 equal to one, to project prices in each future year in the analysis period considered in the NIA. The index value in a given year is a function of the exponential parameter and *year*.

10C.2.2 Increasing Price Scenario

In Figure 10C.2.1 both the cast iron heating boiler PPI and the steel heating boiler PPI show strongly rising trends starting from the early 2000s. As explained in chapter 8, this rise in boiler PPI is primarily due to the increase in prices of various industrial commodities (iron and steel in particular), which resulted from rapid industrialization in China, India, and other emerging economies. Before the economic booms in these emerging countries, the inflation-adjusted PPI for iron and steel mills was in a long downtrend that began in the early 1980s. More recently, iron and steel prices have actually started declining again since the beginning of 2011 due to slower economic growth. Given the past trend and the current economic situation, DOE is not confident that extrapolating the upward trend in the PPI for cast iron heating boilers and steel heating boilers from 1999 to 2014 would provide a sound projection for the increasing price scenario. Therefore, for the increasing price scenario, DOE assumes that the price will increase at the same annual price change percentage as was derived from the decreasing price scenario, 1.14 percent from the previous year. Note that although the percentage change each year is the same in magnitude for the decreasing and increasing scenarios, because each year's price is based on the previous year's price, the two price scenarios are not symmetric.

10C.2.3 Summary

Table 10C.2.1 shows the summary of the average annual rates of change for the PPI in each scenario. Figure 10C.2.5 shows the resulting price trends.

Table 10C.2.1 Price Trend Sensitivities

Sensitivity	Price Trend	Average Annual Rate of Change %
Medium (Default)	Constant price projection	0.0
Decreasing Price Scenario	Exponential fit using the steel heating boiler PPI from 1980 to 1998	-1.14
Increasing Price Scenario	Prices increase at the same annual price change percentage as the decreasing price scenario	1.14

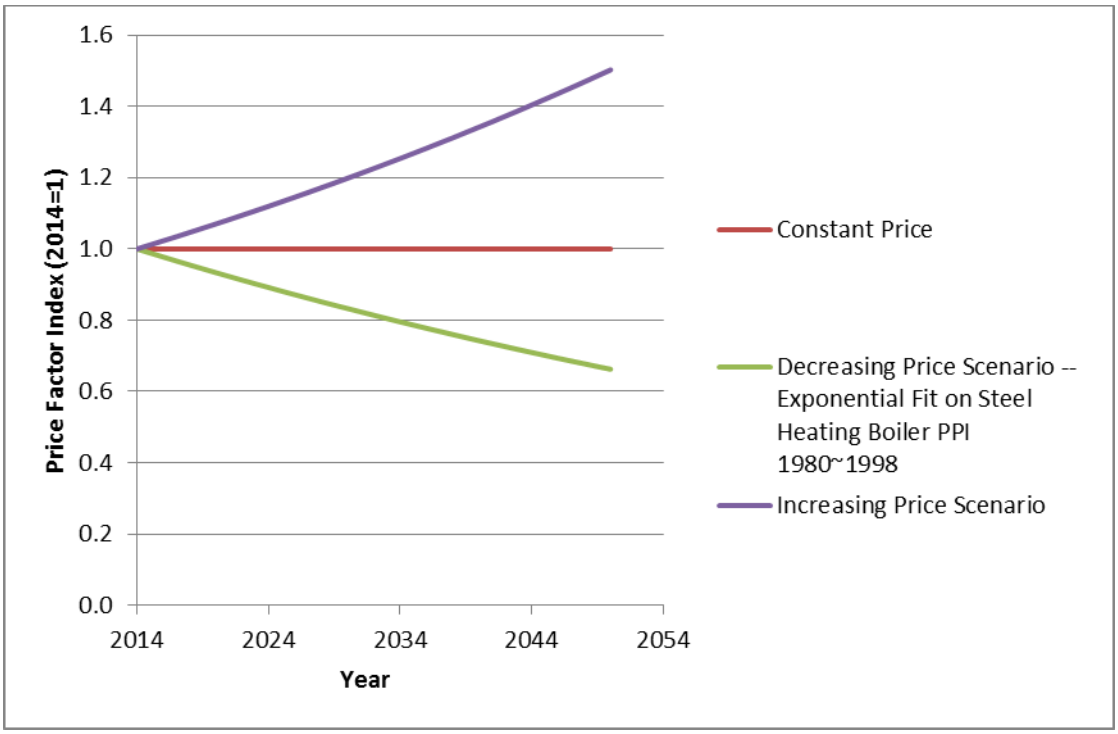

Figure 10C.2.5 Residential Boiler Price Forecast Indexes

10C.3 NET PRESENT VALUE RESULTS USING ALTERNATIVE PRODUCT PRICE TRENDS

This section presents the NPV results using the reference and alternative product price forecasts for each product class. Table 10C.3.7 compares the total (all classes) NPV using the default product price forecast with the NPV using the alternative product price forecasts. With the decreasing price trend, the NPV for the highest TSLs rises substantially compared with the reference case; in contrast, the NPV declines with the increasing price trend.

Table 10C.3.1 NPV Using Reference Product Price Trend, Discounted at 3 Percent, for Residential Boilers (billion 2014$)

Product Class	Trial Standard Level				
	1	2	3	4	5
Gas-fired Hot Water Boiler	0.2549	0.2549	0.5862	1.3162	1.8886
Gas-fired Steam Boiler	0.0347	0.0347	0.0347	0.0347	-0.0229
Oil-fired Hot Water Boiler	0.1648	0.5462	0.5462	-1.3083	-1.3083
Oil-fired Steam Boiler	0.0166	0.0166	0.0311	0.0395	0.0395
Total – All Classes	**0.4710**	**0.8524**	**1.1982**	**0.0819**	**0.5969**

Table 10C.3.2 NPV Using Reference Product Price Trend, Discounted at 7 Percent, for Residential Boilers (billion 2014$)

Product Class	Trial Standard Level				
	1	2	3	4	5
Gas-fired Hot Water Boiler	0.0844	0.0844	0.1941	0.0040	-0.7237
Gas-fired Steam Boiler	0.0113	0.0113	0.0113	0.0113	-0.0397
Oil-fired Hot Water Boiler	0.0351	0.1387	0.1387	-1.3653	-1.3653
Oil-fired Steam Boiler	0.0029	0.0029	0.0058	0.0013	0.0013
Total – All Classes	**0.1338**	**0.2374**	**0.3499**	**-1.3486**	**-2.1272**

Table 10C.3.3 NPV Using Alternative Product Price Trend (Decreasing Trend), Discounted at 3 Percent, for Residential Boilers (billion 2014$)

Product Class	Trial Standard Level				
	1	2	3	4	5
Gas-fired Hot Water Boiler	0.2576	0.2576	0.5924	1.5762	2.9892
Gas-fired Steam Boiler	0.0353	0.0353	0.0353	0.0353	0.0003
Oil-fired Hot Water Boiler	0.1790	0.5805	0.5805	-0.8903	-0.8903
Oil-fired Steam Boiler	0.0188	0.0188	0.0351	0.0481	0.0481
Total – All Classes	**0.4907**	**0.8922**	**1.2434**	**0.7693**	**2.1473**

Table 10C.3.4 NPV Using Alternative Product Price Trend (Decreasing Trend), Discounted at 7 Percent, for Residential Boilers (billion 2014$)

Product Class	Trial Standard Level				
	1	2	3	4	5
Gas-fired Hot Water Boiler	0.0857	0.0857	0.1971	0.1278	-0.2175
Gas-fired Steam Boiler	0.0116	0.0116	0.0116	0.0116	-0.0288
Oil-fired Hot Water Boiler	0.0420	0.1554	0.1554	-1.1630	-1.1630
Oil-fired Steam Boiler	0.0041	0.0041	0.0078	0.0057	0.0057
Total – All Classes	**0.1434**	**0.2568**	**0.3719**	**-1.0179**	**-1.4035**

Table 10C.3.5 NPV Using Alternative Product Price Trend (Increasing Trend), Discounted at 3 Percent, for Residential Boilers (billion 2014$)

Product Class	Trial Standard Level				
	1	2	3	4	5
Gas-fired Hot Water Boiler	0.2515	0.2515	0.5782	0.9854	0.4743
Gas-fired Steam Boiler	0.0339	0.0339	0.0339	0.0339	-0.0524
Oil-fired Hot Water Boiler	0.1469	0.5029	0.5029	-1.8371	-1.8371
Oil-fired Steam Boiler	0.0138	0.0138	0.0260	0.0287	0.0287
Total – All Classes	**0.4461**	**0.8021**	**1.1411**	**-0.7891**	**-1.3865**

Table 10C.3.6 NPV Using Alternative Product Price Trend (Increasing Trend), Discounted at 7 Percent, for Residential Boilers (billion 2014$)

Product Class	Trial Standard Level				
	1	2	3	4	5
Gas-fired Hot Water Boiler	0.0829	0.0829	0.1904	-0.1489	-1.3553
Gas-fired Steam Boiler	0.0109	0.0109	0.0109	0.0109	-0.0532
Oil-fired Hot Water Boiler	0.0266	0.1182	0.1182	-1.6140	-1.6140
Oil-fired Steam Boiler	0.0016	0.0016	0.0033	-0.0040	-0.0040
Total – All Classes	**0.1220**	**0.2136**	**0.3228**	**-1.7559**	**-3.0265**

Table 10C.3.7 Comparison of Total NPV Across All Product Classes for Alternative Product Price Trends (billion 2014$)

Scenario	Discount Rate	Trial Standard Level				
		1	2	3	4	5
Reference Case	3%	0.4710	0.8524	1.1982	0.0819	0.5969
	7%	0.1338	0.2374	0.3499	-1.3486	-2.1272
Decreasing Price Trend	3%	0.4907	0.8922	1.2434	0.7693	2.1473
	7%	0.1434	0.2568	0.3719	-1.0179	-1.4035
Increasing Price Trend	3%	0.4461	0.8021	1.1411	-0.7891	-1.3865
	7%	0.1220	0.2136	0.3228	-1.7559	-3.0265

APPENDIX 10D. NATIONAL IMPACT ANALYSIS USING ALTERNATIVE ECONOMIC GROWTH SCENARIOS FOR RESIDENTIAL BOILERS

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APPENDIX 10D. NATIONAL IMPACT ANALYSIS USING ALTERNATIVE ECONOMIC GROWTH SCENARIOS FOR RESIDENTIAL BOILERS

10D.1 INTRODUCTION

This appendix presents National Impact Analysis (NIA) results using energy price forecasts from alternative economic growth scenarios. The scenarios are based on the High Economic Growth case and the Low Economic Growth case from Energy Information Administration's (EIA's) *Annual Energy Outlook 2015* (*AEO 2015*).[1] To estimate energy prices after 2040 in the high and low scenarios, DOE used the growth rate between 2020 and 2040. See appendix 8C for details about alternative economic growth scenarios.

This appendix also describes the High and Low Economic Growth scenarios in further detail. See appendix 10A for details about how to generate NIA results for High Economic Growth and Low Economic Growth scenarios using the NIA spreadsheet.

10D.2 DESCRIPTION OF HIGH AND LOW ECONOMIC SCENARIOS

To generate NIA results reported in chapter 10, DOE uses the Reference case energy price and housing projections from *AEO 2015*. The reference case is a business-as-usual estimate, given known market, demographic, and technological trends. For *AEO 2015*, EIA explored the impacts of alternative assumptions in other scenarios with different macroeconomic growth rates, world oil prices, rates of technology progress, and policy changes.

To reflect uncertainty in the projection of U.S. economic growth, EIA's *AEO 2015* uses High and Low Economic Growth scenarios to project the possible impacts of alternative economic growth assumptions on energy markets.[2]

Energy prices are higher in the High Economic Growth scenario and lower in the Low Economic Growth scenario. See appendix 8I for details about the effect of these alternative economic scenarios on energy prices.

Because *AEO 2015* provides the price trends by census division, each sampled household is then matched to the appropriate census division price trend. See chapter 10 for details about how energy price trends by census division are applied in the NIA analysis.

In addition, the High and Low Economic Growth scenarios provide different housing start projections that affect the boiler shipments projections. Figure 10D.2.1 shows the total residential boiler shipments projections based on the different *AEO 2015* scenarios.

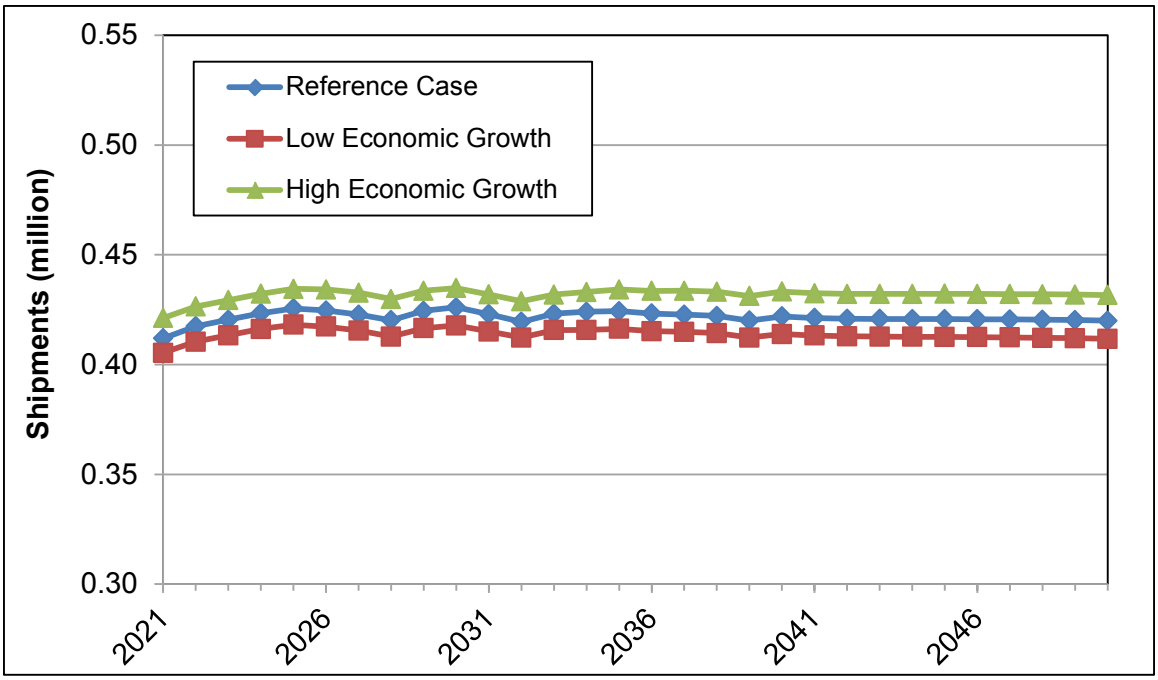

Figure 10D.2.1 Shipment Projections for Reference Case and High and Low Economic Growth Scenarios

10D.3 RESULTS

10D.3.1 National Energy Savings

For AFUE standards, Table 10D.3.1 through Table 10D.3.3 show the national energy savings (NES) results for each of the Trial Standard Levels (TSLs) analyzed for residential boilers AFUE standards using the Reference Case, High Economic Growth, and Low Economic Growth scenarios. For standby mode and off mode standards, Table 10D.3.4 through Table 10D.3.6 show the national energy savings (NES) results for each of the Trial Standard Levels (TSLs) analyzed for residential boilers using the Reference Case, High Economic Growth, and Low Economic Growth scenarios.

Table 10D.3.1 Full-Fuel-Cycle National Energy Savings (Quads) for AFUE Standards – Reference Case

Product Classes	Trial Standard Levels				
	1	2	3	4	5
Gas-fired Hot Water Boiler	0.0405	0.0405	0.0933	0.5941	1.3777
Gas-fired Steam Boiler	0.0058	0.0058	0.0058	0.0058	0.0185
Oil-fired Hot Water Boiler	0.0174	0.0528	0.0528	0.1602	0.1602
Oil-fired Steam Boiler	0.0021	0.0021	0.0038	0.0064	0.0064
Total – All Classes	0.0658	0.1012	0.1557	0.7664	1.5627

Table 10D.3.2 Full-Fuel-Cycle National Energy Savings (Quads) for AFUE Standards – High Economic Growth

Product Classes	Trial Standard Levels				
	1	2	3	4	5
Gas-fired Hot Water Boiler	0.0416	0.0416	0.0958	0.6152	1.4206
Gas-fired Steam Boiler	0.0058	0.0058	0.0058	0.0058	0.0184
Oil-fired Hot Water Boiler	0.0176	0.0534	0.0534	0.1643	0.1643
Oil-fired Steam Boiler	0.0021	0.0021	0.0038	0.0064	0.0064
Total – All Classes	0.0670	0.1028	0.1587	0.7916	1.6096

Table 10D.3.3 Full-Fuel-Cycle National Energy Savings (Quads) for AFUE Standards – Low Economic Growth

Product Classes	Trial Standard Levels				
	1	2	3	4	5
Gas-fired Hot Water Boiler	0.0397	0.0397	0.0913	0.5776	1.3441
Gas-fired Steam Boiler	0.0058	0.0058	0.0058	0.0058	0.0185
Oil-fired Hot Water Boiler	0.0172	0.0524	0.0524	0.1571	0.1571
Oil-fired Steam Boiler	0.0021	0.0021	0.0039	0.0065	0.0065
Total – All Classes	0.0648	0.1000	0.1533	0.7469	1.5262

Table 10D.3.4 Full-Fuel-Cycle National Energy Savings (Quads) for Standby Mode and Off Mode Standards – Reference Case

Product Classes	Trial Standard Levels		
	1	2	3
Gas-fired Hot Water Boiler	0.000719	0.001007	0.002014
Gas-fired Steam Boiler	0.000021	0.000029	0.000058
Oil-fired Hot Water Boiler	0.000162	0.000227	0.000455
Oil-fired Steam Boiler	0.000003	0.000005	0.000009
Electric Hot Water Boiler	0.000017	0.000024	0.000048
Electric Steam Boiler	0.000002	0.000003	0.000006
Total – All Classes	0.000925	0.001295	0.002590

Table 10D.3.5 Full-Fuel-Cycle National Energy Savings (Quads) for Standby Mode and Off Mode Standards – High Economic Growth

Product Classes	Trial Standard Levels		
	1	2	3
Gas-fired Hot Water Boiler	0.000743	0.001040	0.002080
Gas-fired Steam Boiler	0.000021	0.000029	0.000058
Oil-fired Hot Water Boiler	0.000164	0.000230	0.000459
Oil-fired Steam Boiler	0.000003	0.000004	0.000009
Electric Hot Water Boiler	0.000018	0.000025	0.000049
Electric Steam Boiler	0.000002	0.000003	0.000006
Total – All Classes	0.000951	0.001331	0.002662

Table 10D.3.6 Full-Fuel-Cycle National Energy Savings (Quads) for Standby Mode and Off Mode Standards – Low Economic Growth

Product Classes	Trial Standard Levels		
	1	2	3
Gas-fired Hot Water Boiler	0.000702	0.000982	0.001964
Gas-fired Steam Boiler	0.000021	0.000029	0.000059
Oil-fired Hot Water Boiler	0.000161	0.000226	0.000452
Oil-fired Steam Boiler	0.000003	0.000005	0.000009
Electric Hot Water Boiler	0.000017	0.000023	0.000047
Electric Steam Boiler	0.000002	0.000003	0.000006
Total – All Classes	0.000906	0.001268	0.002536

10D.3.2 Net Present Value of Consumer Impacts

For AFUE standards, Table 10D.3.7 through Table 10D.3.12 show the national present value (NPV) results for each of the TSLs analyzed for residential boilers for AFUE standards using the Reference Case, High Economic Growth, and Low Economic Growth scenarios. For standby mode and off mode standards, Table 10D.3.13 through Table 10D.3.18 show the NPV results for each of the TSLs analyzed using the Reference Case, High Economic Growth, and Low Economic Growth scenarios. A negative NPV indicates that the costs of a standard at a given efficiency level exceed the savings.

Table 10D.3.7 Net Present Value, Discounted at 3 Percent (Billion 2014$) for AFUE Standards – Reference Case

Product Classes	Trial Standard Levels				
	1	2	3	4	5
Gas-fired Hot Water Boiler	0.2549	0.2549	0.5862	1.3162	1.8886
Gas-fired Steam Boiler	0.0347	0.0347	0.0347	0.0347	-0.0229
Oil-fired Hot Water Boiler	0.1648	0.5462	0.5462	-1.3083	-1.3083
Oil-fired Steam Boiler	0.0166	0.0166	0.0311	0.0395	0.0395
Total – All Classes	0.4710	0.8524	1.1982	0.0819	0.5969

Table 10D.3.8 Net Present Value, Discounted at 7 Percent (Billion 2014$) for AFUE Standards – Reference Case

Product Classes	Trial Standard Levels				
	1	2	3	4	5
Gas-fired Hot Water Boiler	0.0844	0.0844	0.1941	0.0040	-0.7237
Gas-fired Steam Boiler	0.0113	0.0113	0.0113	0.0113	-0.0397
Oil-fired Hot Water Boiler	0.0351	0.1387	0.1387	-1.3653	-1.3653
Oil-fired Steam Boiler	0.0029	0.0029	0.0058	0.0013	0.0013
Total – All Classes	0.1338	0.2374	0.3499	-1.3486	-2.1272

Table 10D.3.9 Net Present Value, Discounted at 3 Percent (Billion 2014$) for AFUE Standards – High Economic Growth

Product Classes	Trial Standard Levels				
	1	2	3	4	5
Gas-fired Hot Water Boiler	0.2793	0.2793	0.6423	1.7221	2.6375
Gas-fired Steam Boiler	0.0369	0.0369	0.0369	0.0369	-0.0150
Oil-fired Hot Water Boiler	0.1777	0.5849	0.5849	-1.1016	-1.1016
Oil-fired Steam Boiler	0.0177	0.0177	0.0330	0.0428	0.0428
Total – All Classes	0.5116	0.9188	1.2972	0.7003	1.5637

Table 10D.3.10 Net Present Value, Discounted at 7 Percent (Billion 2014$) for AFUE Standards – High Economic Growth

Product Classes	Trial Standard Levels				
	1	2	3	4	5
Gas-fired Hot Water Boiler	0.0920	0.0920	0.2116	0.1334	-0.5230
Gas-fired Steam Boiler	0.0121	0.0121	0.0121	0.0121	-0.0373
Oil-fired Hot Water Boiler	0.0388	0.1501	0.1501	-1.3016	-1.3016
Oil-fired Steam Boiler	0.0033	0.0033	0.0064	0.0025	0.0025
Total – All Classes	0.1463	0.2575	0.3801	-1.1537	-1.8594

Table 10D.3.11 Net Present Value, Discounted at 3 Percent (Billion 2014$) for AFUE Standards – Low Economic Growth

Product Classes	Trial Standard Levels				
	1	2	3	4	5
Gas-fired Hot Water Boiler	0.2323	0.2323	0.5342	0.9158	1.1399
Gas-fired Steam Boiler	0.0320	0.0320	0.0320	0.0320	-0.0322
Oil-fired Hot Water Boiler	0.1546	0.5160	0.5160	-1.4662	-1.4662
Oil-fired Steam Boiler	0.0157	0.0157	0.0294	0.0366	0.0366
Total – All Classes	0.4346	0.7961	1.1117	-0.4819	-0.3220

Table 10D.3.12 Net Present Value, Discounted at 7 Percent (Billion 2014$) for AFUE Standards – Low Economic Growth

Product Classes	Trial Standard Levels				
	1	2	3	4	5
Gas-fired Hot Water Boiler	0.0781	0.0781	0.1795	-0.1069	-0.9021
Gas-fired Steam Boiler	0.0106	0.0106	0.0106	0.0106	-0.0421
Oil-fired Hot Water Boiler	0.0319	0.1289	0.1289	-1.4160	-1.4160
Oil-fired Steam Boiler	0.0026	0.0026	0.0051	0.0003	0.0003
Total – All Classes	0.1232	0.2202	0.3241	-1.5120	-2.3598

Table 10D.3.13 Net Present Value, Discounted at 3 Percent (Billion 2014$) for Standby Mode and Off Mode Standards – Reference Case

Product Classes	Trial Standard Levels		
	1	2	3
Gas-fired Hot Water Boiler	0.0054	0.0028	0.0107
Gas-fired Steam Boiler	0.0002	0.0001	0.0003
Oil-fired Hot Water Boiler	0.0013	0.0007	0.0026
Oil-fired Steam Boiler	0.0000	0.0000	0.0001
Electric Hot Water Boiler	0.0001	0.0000	0.0001
Electric Steam Boiler	0.0000	0.0000	0.0000
Total – All Classes	0.0070	0.0036	0.0139

Table 10D.3.14 Net Present Value, Discounted at 7 Percent (Billion 2014$) for Standby Mode and Off Mode Standards – Reference Case

Product Classes	Trial Standard Levels		
	1	2	3
Gas-fired Hot Water Boiler	0.0017	-0.00005	0.0025
Gas-fired Steam Boiler	0.0001	0.00000	0.0001
Oil-fired Hot Water Boiler	0.0005	0.00002	0.0007
Oil-fired Steam Boiler	0.0000	0.00000	0.0000
Electric Hot Water Boiler	0.0000	-0.00002	0.0000
Electric Steam Boiler	0.0000	0.00000	0.0000
Total – All Classes	0.0023	-0.00005	0.0034

Table 10D.3.15 Standby Mode and Off Mode Standards: Net Present Value, Discounted at 3 Percent (Billion 2014$) – High Economic Growth

Product Classes	Trial Standard Levels		
	1	2	3
Gas-fired Hot Water Boiler	0.0059	0.0033	0.0118
Gas-fired Steam Boiler	0.0002	0.0001	0.0003
Oil-fired Hot Water Boiler	0.0014	0.0008	0.0028
Oil-fired Steam Boiler	0.0000	0.0000	0.0001
Electric Hot Water Boiler	0.0001	0.0000	0.0002
Electric Steam Boiler	0.0000	0.0000	0.0000
Total – All Classes	0.0075	0.0042	0.0152

Table 10D.3.16 Net Present Value, Discounted at 7 Percent (Billion 2014$) for Standby Mode and Off Mode Standards – High Economic Growth

Product Classes	Trial Standard Levels		
	1	2	3
Gas-fired Hot Water Boiler	0.0018	0.0000	0.0028
Gas-fired Steam Boiler	0.0001	0.0000	0.0001
Oil-fired Hot Water Boiler	0.0005	0.0000	0.0008
Oil-fired Steam Boiler	0.0000	0.0000	0.0000
Electric Hot Water Boiler	0.0000	0.0000	0.0000
Electric Steam Boiler	0.0000	0.0000	0.0000
Total – All Classes	0.0024	0.0001	0.0037

Table 10D.3.17 Net Present Value, Discounted at 3 Percent (Billion 2014$) for Standby Mode and Off Mode Standards – Low Economic Growth

Product Classes	Trial Standard Levels		
	1	2	3
Gas-fired Hot Water Boiler	0.0053	0.0027	0.0104
Gas-fired Steam Boiler	0.0002	0.0001	0.0003
Oil-fired Hot Water Boiler	0.0013	0.0007	0.0026
Oil-fired Steam Boiler	0.0000	0.0000	0.0001
Electric Hot Water Boiler	0.0001	0.0000	0.0001
Electric Steam Boiler	0.0000	0.0000	0.0000
Total – All Classes	0.0068	0.0035	0.0136

Table 10D.3.18 Net Present Value, Discounted at 7 Percent (Billion 2014$) for Standby Mode and Off Mode Standards – Low Economic Growth

Product Classes	Trial Standard Levels		
	1	2	3
Gas-fired Hot Water Boiler	0.0017	-0.0001	0.0024
Gas-fired Steam Boiler	0.0001	0.0000	0.0001
Oil-fired Hot Water Boiler	0.0004	0.0000	0.0007
Oil-fired Steam Boiler	0.0000	0.0000	0.0000
Electric Hot Water Boiler	0.0000	0.0000	0.0000
Electric Steam Boiler	0.0000	0.0000	0.0000
Total – All Classes	0.0022	-0.0001	0.0032

10D.3.3 Summary

Table 10D.3.19 shows the NES and NPV results for each of the TSL for the Reference case and the High Economic Growth and Low Economic Growth scenarios for AFUE standards. Table 10D.3.20 shows the NES and NPV results for standby mode and off mode standards. NES and NPV results are larger for High Economic Growth scenario and smaller for Low Economic Growth scenario compared to Reference case.

Table 10D.3.19 Comparison of Energy Savings and Net Present Value Results for AFUE Standards – Reference Case and High and Low Economic Growth Scenarios

Scenario		Trial Standard Level				
		1	2	3	4	5
FFC Energy Savings (quads)	Reference	0.0658	0.1012	0.1557	0.7664	1.5627
	High Economic Growth	0.0670	0.1028	0.1587	0.7916	1.6096
	Low Economic Growth	0.0648	0.1000	0.1533	0.7469	1.5262
NPV 3% (billion 2014$)	Reference	0.4710	0.8524	1.1982	0.0819	0.5969
	High Economic Growth	0.5116	0.9188	1.2972	0.7003	1.5637
	Low Economic Growth	0.4346	0.7961	1.1117	-0.4819	-0.3220
NPV 7% (billion 2014$)	Reference	0.1338	0.2374	0.3499	-1.3486	-2.1272
	High Economic Growth	0.1463	0.2575	0.3801	-1.1537	-1.8594
	Low Economic Growth	0.1232	0.2202	0.3241	-1.5120	-2.3598

Table 10D.3.20 Comparison of Energy Savings and Net Present Value Results for Standby Mode and Off Mode Standards – Reference Case and High and Low Economic Growth Scenarios

Scenario		Trial Standard Level		
		1	2	3
FFC Energy Savings (quads)	Reference	0.000925	0.001295	0.002590
	High Economic Growth	0.000951	0.001331	0.002662
	Low Economic Growth	0.000906	0.001268	0.002536
NPV 3% (billion 2014$)	Reference	0.0070	0.0036	0.0139
	High Economic Growth	0.0075	0.0042	0.0152
	Low Economic Growth	0.0068	0.0035	0.0136
NPV 7% (billion 2014$)	Reference	0.0023	-0.00005	0.0034
	High Economic Growth	0.0024	0.0001	0.0037
	Low Economic Growth	0.0022	-0.0001	0.0032

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CHAPTER 11. CONSUMER SUBGROUP ANALYSIS

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CHAPTER 11. CONSUMER SUBGROUP ANALYSIS

11.1 INTRODUCTION

The consumer subgroup analysis evaluates impacts on groups or customers who may be disproportionately affected by any national energy conservation standard. The U.S. Department of Energy (DOE) evaluates impacts on particular subgroups of consumers by analyzing the life-cycle cost (LCC) impacts and payback period (PBP) for those consumers from the considered energy efficiency levels. DOE determined the impact on consumer subgroups using the LCC spreadsheet models for residential boilers. Chapter 8 explains in detail the inputs to the models used in determining LCC impacts and PBPs.

DOE evaluated impacts of the impacts of the considered energy efficiency levels for residential boilers on low-income households and households occupied solely by senior citizens (*i.e.*, senior-only households). This chapter describes the subgroup identification in further detail and gives the results of the LCC and PBP analyses for the considered subgroups.

11.2 APPROACH

11.2.1 Low-Income Households

As defined in the Energy Information Administration's 2009 Residential Energy Consumption Survey (RECS 2009) survey,[1] low-income households are those at or below the "poverty line." The poverty line varies with household size, head of household age, and family income and in RECS encompasses a group of households with incomes below the poverty level in 2009 as defined by the U.S. Bureau of the Census[2] (see Table 11.2.1). The RECS survey classifies approximately 15 percent of U.S. households as low-income.

Table 11.2.1 RECS 2009 Definitions of Low-Income Households by Yearly Income

Household Size	Weighted Average Threshold *2009$*
1	10,956
2	13,991
3	17,098
4	21,954
5	25,991
6	29,405
7	33,372
8	37,252
9+	44,366

11.2.2 Senior-Only Households

Senior-only households have occupants who are all at least 65 years of age. Based on RECS 2009, senior-only households comprise 17 percent of the country's households.

11.2.3 Distribution of Subgroup Households with Residential Boilers

Of the 12,083 household records in RECS 2009, 685 gas-fired boilers, 437 oil-fired boilers, and 41 electric boilers are associated with the general population, 103 gas-fired boilers, 43 oil-fired boilers, and 9 electric boilers are associated with low income households, and 164 gas-fired boilers, 120 oil-fired boilers, and 11 electric boilers are associated with senior-only households. Table 11.2.2 shows the household sample sizes for all residential boiler product classes.[a] Table 11.2.3 and Table 11.2.4 show the average space heating load, fraction using boiler for water heating, water heating load, average square footage, and average energy prices for the general population and for the low income and for senior only for all residential boiler product classes.

Table 11.2.2 Household Population Data for all Residential Boiler Products

Product Class	General Population		Low-Income Households		Senior-Only Households	
	RECS 2009 No. of Records	DOE 2021 No. of Boiler Shipments (thousands)	RECS 2009 No. of Records	DOE 2021 No. of Boiler Shipments (thousands)	RECS 2009 No. of Records	DOE 2021 No. of Boiler Shipments (thousands)
Gas-Fired Hot Water Boilers	685	224.65	103	24.02	164	60.22
Gas-Fired Steam Boilers	497	28.49	81	3.48	114	7.71
Oil-Fired Hot Water Boilers	437	77.17	43	4.16	120	25.06
Oil-Fired Steam Boilers	325	8.23	36	0.49	96	2.91
Electric Hot Water Boiler	41	11.36	9	2.56	11	5.39
Electric Steam Boiler	26	2.01	5	0.14	10	1.29

Table 11.2.3 Household Average Heating Load, Fraction Using Boiler for Water Heating, and Average Water Heating Load

Product Class	House Heating Load (MMBtu)			Fraction Using Boiler for Water Heating (%)			Water Heating Load (MMBtu)		
	Low-Income	Senior	All	Low-Income	Senior	All	Low-Income	Senior	All
Gas-Fired Hot Water Boilers	72.99	72.14	92.97	33.5%	42.0%	41.1%	14.75	14.22	19.38
Gas-Fired Steam Boilers	75.84	80.11	99.15	2.9%	4.4%	4.6%	15.25	15.41	17.51
Oil-Fired Hot Water Boilers	64.28	96.65	88.41	31.6%	31.1%	35.9%	10.38	9.91	14.67
Oil-Fired Steam Boilers	63.07	99.49	93.11	6.2%	9.0%	9.4%	13.16	11.41	15.27
Electric Hot Water Boiler	13.77	14.00	17.65	41.5%	21.5%	26.6%	5.86	14.28	26.27
Electric Steam Boiler	11.09	13.74	18.89	0.0%	1.7%	2.2%	---	13.52	22.88

[a] Note that the total of these records is not an estimate of the number of buildings that use a residential boiler. Because RECS 2009 does not report the heating medium (hot water or steam), DOE used samples for hot water and steam boiler product classes that include all houses that might use either hot water or steam. For steam boilers in particular, this results in a sample size that represents many more houses than actually use steam boilers.

Table 11.2.4 Household Average Square Footage, Average Fuel Price, and Average Electricity Price

Product Class	Building Square Footage (sq ft)			Fuel Price in 2013 (2014$/MMBtu)			Electricity Price in 2013 (2014$/kWh)		
	Low-Income	Senior	All	Low-Income	Senior	All	Low-Income	Senior	All
Gas-Fired Hot Water Boilers	1314.2	1994.3	2593.9	17.1	13.6	12.8	0.158	0.146	0.151
Gas-Fired Steam Boilers	1332.8	1806.3	2496.8	17.8	11.8	12.3	0.158	0.146	0.152
Oil-Fired Hot Water Boilers	1449.1	2200.1	2403.3	27.6	29.4	29.0	0.193	0.152	0.158
Oil-Fired Steam Boilers	1378.0	2138.1	2335.6	28.0	29.3	29.2	0.188	0.155	0.162
Electric Hot Water Boiler	1839.7	3299.3	4429.2	26.7	33.2	28.8	0.093	0.115	0.102
Electric Steam Boiler	755.9	3291.5	5129.5	35.4	33.3	29.2	0.125	0.115	0.103

11.2.4 Estimation of Impacts

To calculate the subgroup results, DOE extracted the results of low-income and senior-only households from the national LCC results. Then DOE calculated the LCC and PBP statistics for the subgroups from the individual households.

11.3 RESULTS

11.3.1 Results for AFUE Standards

Table 11.3.1 and Table 11.3.2 summarize the LCC and PBP results for low-income and senior-only households for AFUE standards. Table 11.3.3 compares average LCC savings for the consumer subgroups with those for all households for AFUE standards. For gas and oil-fired hot water boilers, the low-income households have negative LCC savings for the higher efficiency boilers.

Table 11.3.1 LCC and PBP Results for Low-Income Households for AFUE Standards

Product Class	Efficiency Level	Average Costs *2014$*				Simple Payback Period *years*	Average Lifetime *years*
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
Gas-fired Hot Water Boiler	Baseline	$5,922	$986	$18,863	$24,785	-	26.6
	1	$5,937	$976	$18,669	$24,607	1.5	26.6
	2	$5,953	$966	$18,480	$24,433	1.5	26.6
	3	$6,292	$957	$18,324	$24,617	13.0	26.6
	4	$7,069	$912	$17,490	$24,559	15.6	26.6
	5	$7,419	$896	$17,184	$24,603	16.7	26.6
	6	$8,108	$866	$16,612	$24,720	18.2	26.6
Gas-fired Steam Boiler	Baseline	$6,076	$884	$15,172	$21,248	-	23.6
	1	$6,130	$865	$14,857	$20,987	2.9	23.6
	2	$6,425	$857	$14,708	$21,133	12.7	23.6
Oil-fired Hot Water Boiler	Baseline	$7,567	$1,445	$27,653	$35,220	-	24.7
	1	$7,721	$1,430	$27,368	$35,089	10.6	24.7
	2	$7,874	$1,409	$26,964	$34,839	8.6	24.7
	3	$10,538	$1,348	$25,752	$36,290	30.6	24.7
Oil-fired Steam Boiler	Baseline	$7,546	$1,351	$19,951	$27,497	-	19.3
	1	$7,855	$1,321	$19,509	$27,363	10.4	19.3
	2	$8,009	$1,307	$19,295	$27,305	10.5	19.3
	3	$8,318	$1,288	$19,007	$27,325	12.2	19.3

Table 11.3.2 LCC Savings relative to No-New-Standards Case for Low-Income Households for AFUE Standards

Product Class	Efficiency Level	Life-Cycle Cost Savings	
		% of Consumers that Experience Net Cost	Average Savings
Gas-fired Hot Water Boiler	Baseline		$0
	1	4.2%	$161
	2	3.5%	$275
	3	36.5%	$25
	4	56.2%	($89)
	5	61.6%	($134)
	6	65.2%	($200)
Gas-fired Steam Boiler	Baseline		$0
	1	7.7%	$265
	2	43.3%	$116
Oil-fired Hot Water Boiler	Baseline		$0
	1	41.0%	$82
	2	23.8%	$292
	3	82.0%	($1,260)
Oil-fired Steam Boiler	Baseline		$0
	1	45.6%	$138
	2	44.8%	$141
	3	55.5%	$96

Table 11.3.3 LCC and PBP Results for Senior Only Households for AFUE Standards

Product Class	Efficiency Level	Average Costs *2014$*				Simple Payback Period *years*	Average Lifetime *years*
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
Gas-fired Hot Water Boiler	Baseline	$6,022	$1,142	$20,874	$26,896	-	26.6
	1	$6,038	$1,130	$20,655	$26,693	1.3	26.6
	2	$6,053	$1,118	$20,442	$26,495	1.3	26.6
	3	$6,304	$1,107	$20,246	$26,550	8.1	26.6
	4	$6,882	$1,042	$19,068	$25,950	8.6	26.6
	5	$7,235	$1,024	$18,730	$25,965	10.3	26.6
	6	$7,928	$989	$18,098	$26,026	12.4	26.6
Gas-fired Steam Boiler	Baseline	$5,986	$949	$15,534	$21,519	-	23.6
	1	$6,051	$928	$15,200	$21,252	3.2	23.6
	2	$6,349	$918	$15,043	$21,392	12.0	23.6
Oil-fired Hot Water Boiler	Baseline	$7,878	$2,135	$40,700	$48,578	-	24.7
	1	$8,030	$2,112	$40,249	$48,278	6.5	24.7
	2	$8,182	$2,079	$39,620	$47,802	5.4	24.7
	3	$10,669	$1,965	$37,412	$48,080	16.4	24.7
Oil-fired Steam Boiler	Baseline	$7,798	$2,083	$31,551	$39,349	-	19.3
	1	$8,103	$2,035	$30,814	$38,916	6.3	19.3
	2	$8,255	$2,011	$30,459	$38,714	6.4	19.3
	3	$8,560	$1,980	$29,979	$38,538	7.4	19.3

Table 11.3.4 LCC Savings relative to No-New-Standards Case for Senior Only Households for AFUE Standards

Product Class	Efficiency Level	Life-Cycle Cost Savings	
		% of Consumers that Experience Net Cost	Average Savings
Gas-fired Hot Water Boiler	Baseline		$0
	1	0.4%	$172
	2	0.6%	$292
	3	15.1%	$92
	4	23.6%	$345
	5	32.5%	$224
	6	59.7%	$67
Gas-fired Steam Boiler	Baseline		$0
	1	0.8%	$306
	2	35.7%	$124
Oil-fired Hot Water Boiler	Baseline		$0
	1	9.7%	$282
	2	8.1%	$690
	3	58.8%	$144
Oil-fired Steam Boiler	Baseline		$0
	1	9.4%	$425
	2	15.6%	$465
	3	27.4%	$543

Table 11.3.5 Comparison of Average LCC Savings and Median Payback Period Results for Consumer Subgroups and All Households for AFUE Standards

Product Class	EL	Average LCC Savings			% of Consumers that Experience Net Cost			Simple Payback Period		
		2014$						Years		
		Low-Income	Senior	All	Low-Income	Senior	All	Low-Income	Senior	All
Gas-fired Hot Water Boiler	1	$161	$172	$210	4.2%	0.4%	0.3%	1.5	1.3	1.2
	2	$275	$292	$364	3.5%	0.6%	0.4%	1.5	1.3	1.2
	3	$25	$92	$182	36.5%	15.1%	13.0%	13.0	8.1	7.5
	4	($89)	$345	$632	56.2%	23.6%	21.9%	15.6	8.6	8.4
	5	($134)	$224	$513	61.6%	32.5%	29.2%	16.7	10.3	9.9
	6	($200)	$67	$303	65.2%	59.7%	55.5%	18.2	12.4	11.8
Gas-fired Steam Boiler	1	$265	$306	$333	7.7%	0.8%	0.9%	2.9	3.2	2.7
	2	$116	$124	$207	43.3%	35.7%	30.8%	12.7	12.0	10.7
Oil-fired Hot Water Boiler	1	$82	$282	$260	41.0%	9.7%	10.4%	10.6	6.5	6.9
	2	$292	$690	$626	23.8%	8.1%	8.8%	8.6	5.4	5.8
	3	($1,260)	$144	$192	82.0%	58.8%	58.9%	30.6	16.4	16.5
Oil-fired Steam Boiler	1	$138	$425	$400	45.6%	9.4%	11.9%	10.4	6.3	6.6
	2	$141	$465	$434	44.8%	15.6%	19.7%	10.5	6.4	6.7
	3	$96	$543	$505	55.5%	27.4%	34.2%	12.2	7.4	7.8

11.3.2 Results for Standby and Off Mode Standards

Table 11.3.1 and Table 11.3.3 summarize the LCC and PBP results for low-income and senior-only households for standby and off mode standards. Table 11.3.5 compares average LCC savings for the consumer subgroups with those for all households for standby and off mode standards.

Table 11.3.6 LCC and PBP Results for Low-Income Households for Standby and Off Mode Standards

Product Class	Efficiency Level	Average Costs *2014$*				Simple Payback Period *years*	Average Lifetime *years*
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
Gas-fired Hot Water Boiler	Baseline	$28	$15	$273	$301	-	26.6
	1	$32	$13	$237	$269	2.0	26.6
	2	$48	$12	$230	$279	8.8	26.6
	3	$49	$12	$214	$263	6.7	26.6
Gas-fired Steam Boiler	Baseline	$28	$14	$240	$267	-	23.6
	1	$32	$12	$206	$237	1.9	23.6
	2	$48	$12	$199	$247	8.5	23.6
	3	$49	$11	$183	$232	6.4	23.6
Oil-fired Hot Water Boiler	Baseline	$28	$23	$389	$417	-	24.7
	1	$32	$20	$346	$378	1.5	24.7
	2	$48	$20	$337	$386	6.8	24.7
	3	$49	$18	$317	$367	5.1	24.7
Oil-fired Steam Boiler	Baseline	$28	$22	$298	$326	-	19.3
	1	$32	$19	$265	$297	1.6	19.3
	2	$49	$19	$258	$307	7.1	19.3
	3	$50	$18	$243	$292	5.4	19.3
Electric Hot Water Boiler	Baseline	$29	$9	$162	$191	-	26.6
	1	$33	$8	$139	$172	2.9	26.6
	2	$49	$7	$135	$183	13.1	26.6
	3	$50	$7	$124	$174	9.9	26.6
Electric Steam Boiler	Baseline	$28	$12	$201	$229	-	23.6
	1	$32	$10	$173	$205	2.2	23.6
	2	$49	$10	$168	$216	10.1	23.6
	3	$50	$9	$154	$204	7.6	23.6

Table 11.3.7 LCC Savings relative to No-New-Standards Case for Low-Income Households for Standby and Off Mode Standards

Product Class	Efficiency Level	Life-Cycle Cost Savings	
		% of Consumers that Experience Net Cost	Average Savings
Gas-fired Hot Water Boiler	Baseline	-	-
	1	0.0%	$20
	2	0.4%	$0
	3	0.2%	$15
Gas-fired Steam Boiler	Baseline	-	-
	1	0.0%	$30
	2	0.2%	$5
	3	0.1%	$19
Oil-fired Hot Water Boiler	Baseline	-	-
	1	0.0%	$40
	2	0.1%	$18
	3	0.0%	$38
Oil-fired Steam Boiler	Baseline	-	-
	1	0.0%	$16
	2	0.1%	($5)
	3	0.0%	$9
Electric Hot Water Boiler	Baseline	-	-
	1	0.0%	$12
	2	0.4%	($7)
	3	0.3%	$3
Electric Steam Boiler	Baseline	-	-
	1	0.0%	$25
	2	0.1%	($4)
	3	0.1%	$7

Table 11.3.8 LCC and PBP Results for Senior Only Households for Standby and Off Mode Standards

Product Class	Efficiency Level	Average Costs *2014$*				Simple Payback Period *years*	Average Lifetime *years*
		Installed Cost	First Year's Operating Cost	Lifetime Operating Cost	LCC		
Gas-fired Hot Water Boiler	Baseline	$29	$14	$248	$276	-	26.6
	1	$32	$12	$215	$247	2.1	26.6
	2	$49	$12	$208	$257	9.2	26.6
	3	$50	$11	$193	$243	7.0	26.6
Gas-fired Steam Boiler	Baseline	$28	$13	$213	$241	-	23.6
	1	$32	$11	$182	$214	2.0	23.6
	2	$48	$11	$176	$224	8.9	23.6
	3	$49	$10	$161	$211	6.7	23.6
Oil-fired Hot Water Boiler	Baseline	$28	$18	$300	$328	-	24.7
	1	$32	$16	$267	$298	1.9	24.7
	2	$48	$15	$260	$308	8.5	24.7
	3	$49	$14	$244	$293	6.4	24.7
Oil-fired Steam Boiler	Baseline	$28	$18	$250	$278	-	19.3
	1	$32	$16	$222	$253	1.9	19.3
	2	$48	$16	$216	$264	8.4	19.3
	3	$49	$15	$203	$252	6.3	19.3
Electric Hot Water Boiler	Baseline	$27	$11	$191	$218	-	26.6
	1	$31	$9	$163	$194	2.4	26.6
	2	$48	$9	$158	$206	11.0	26.6
	3	$49	$8	$145	$194	8.3	26.6
Electric Steam Boiler	Baseline	$27	$11	$165	$192	-	23.6
	1	$31	$9	$141	$172	2.5	23.6
	2	$48	$9	$136	$185	11.3	23.6
	3	$49	$8	$125	$175	8.5	23.6

Table 11.3.9 LCC Savings relative to No-New-Standards Case for Senior Only Households for Standby and Off Mode Standards

Product Class	Efficiency Level	Life-Cycle Cost Savings	
		% of Consumers that Experience Net Cost	Average Savings
Gas-fired Hot Water Boiler	Baseline	-	-
	1	0.0%	$27
	2	0.6%	$3
	3	0.3%	$16
Gas-fired Steam Boiler	Baseline	-	-
	1	0.0%	$22
	2	0.2%	($4)
	3	0.1%	$11
Oil-fired Hot Water Boiler	Baseline	-	-
	1	0.0%	$30
	2	0.7%	$4
	3	0.3%	$17
Oil-fired Steam Boiler	Baseline	-	-
	1	0.0%	$18
	2	0.3%	($4)
	3	0.2%	$9
Electric Hot Water Boiler	Baseline	-	-
	1	0.0%	$26
	2	0.2%	($1)
	3	0.1%	$13
Electric Steam Boiler	Baseline	-	-
	1	0.0%	$19
	2	0.4%	($3)
	3	0.3%	$8

Table 11.3.10 Comparison of Average LCC Savings and Median Payback Period Results for Consumer Subgroups and All Households for Standby and Off Mode Standards

Product Class	EL	Average LCC Savings *2014$*			% of Consumers that Experience Net Cost			Simple Payback Period *Years*		
		Low-Income	Senior	All	Low-Income	Senior	All	Low-Income	Senior	All
Gas-fired Hot Water Boiler	1	$20	$27	$26	0.0%	0.0%	0.0%	2.0	2.1	2.0
	2	$0	$3	$2	0.4%	0.6%	3.7%	8.8	9.2	8.9
	3	$15	$16	$15	0.2%	0.3%	1.8%	6.7	7.0	6.7
Gas-fired Steam Boiler	1	$30	$22	$31	0.0%	0.0%	0.0%	1.9	2.0	1.9
	2	$5	($4)	$4	0.2%	0.2%	1.3%	8.5	8.9	8.5
	3	$19	$11	$18	0.1%	0.1%	0.5%	6.4	6.7	6.4
Oil-fired Hot Water Boiler	1	$40	$30	$32	0.0%	0.0%	0.0%	1.5	1.9	1.8
	2	$18	$4	$6	0.1%	0.7%	3.5%	6.8	8.5	8.2
	3	$38	$17	$20	0.0%	0.3%	1.4%	5.1	6.4	6.2
Oil-fired Steam Boiler	1	$16	$18	$26	0.0%	0.0%	0.0%	1.6	1.9	1.8
	2	($5)	($4)	$0	0.1%	0.3%	1.3%	7.1	8.4	8.0
	3	$9	$9	$13	0.0%	0.2%	0.6%	5.4	6.3	6.1
Electric Hot Water Boiler	1	$12	$26	$19	0.0%	0.0%	0.0%	2.9	2.4	2.6
	2	($7)	($1)	($3)	0.4%	0.2%	1.5%	13.1	11.0	11.7
	3	$3	$13	$8	0.3%	0.1%	1.0%	9.9	8.3	8.9
Electric Steam Boiler	1	$25	$19	$17	0.0%	0.0%	0.0%	2.2	2.5	2.6
	2	($4)	($3)	($5)	0.1%	0.4%	1.5%	10.1	11.3	11.7
	3	$7	$8	$6	0.1%	0.3%	1.0%	7.6	8.5	8.8

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CHAPTER 12. MANUFACTURER IMPACT ANALYSIS

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CHAPTER 12. MANUFACTURER IMPACT ANALYSIS

12.1 INTRODUCTION

In determining whether a standard is economically justified, the U.S. Department of Energy (DOE) is required to consider the economic impact of the standard on the manufacturers and consumers of the products subject to such a standard. (42 U.S.C. 6313(a)(6)(B)(i)) The law also calls for an assessment of the impact of any lessening of competition as determined in writing by the Attorney General. *Id*. DOE conducted a manufacturer impact analysis (MIA) to estimate the financial impact of amended energy conservation standards on manufacturers of residential boilers, and assessed the impact of such standards on direct employment and manufacturing capacity.

The MIA has both quantitative and qualitative aspects. The quantitative part of the MIA primarily relies on the Government Regulatory Impact Model (GRIM), an industry cash-flow model adapted for each product in this rulemaking. The GRIM inputs include information on industry cost structure, shipments, and pricing strategies. The GRIM's key output is the industry net present value (INPV). The model estimates the financial impact of more stringent energy conservation standards for each product by comparing changes in INPV between a no-new-standards case (without new or amended standards) and the various trial standard levels (TSLs) in the standards case. The qualitative part of the MIA addresses product characteristics, manufacturer characteristics, and market and product trends, as well as the impact of standards on subgroups of manufacturers.

12.2 METHODOLOGY

DOE conducted the MIA in three phases. Phase I, "Industry Profile," consisted of preparing an industry characterization for the residential boiler industry. This characterization included data on sales volumes, pricing, employment, and financial structure. In Phase II, "Industry Cash Flow," DOE used the GRIM to assess the potential impacts of amended energy conservation standards on manufacturers. DOE also reached out to a wide range of residential boiler manufacturers to invite them to participate in an MIA interview. DOE developed an interview guide that was distributed to participating manufacturers prior to the interviews. DOE used this guide to help steer conversations with manufacturers about potential impacts of amended standards. In Phase III, "Subgroup Impact Analysis," DOE interviewed manufacturers that account for approximately 46 percent of domestic residential boiler sales. DOE used the information gathered in these interviews to refine the GRIM analysis and to develop additional analyses for subgroups that may be affected in various ways. DOE also incorporated qualitative data from interviews into its analysis. Each phase of the MIA is described in greater detail in the following sections.

12.2.1 Phase I: Industry Profile

In Phase I of the MIA, DOE prepared a profile of the residential boiler industry that built on the market and technology assessment (MTA) prepared for this rulemaking. (The MTA is explained in detail in chapter 3 of this final rule notice technical support document (TSD).)

Before initiating detailed impact analyses, DOE collected information on past and present market characteristics of the residential boiler industry. This information included shipment data, manufacturer markups, manufacturer market shares, and consolidation trends. As part its industry profile research, DOE also collected information on industry financial parameters, such as net plant, property, and equipment (PPE); selling, general and administrative (SG&A) expenses; cost of goods sold, etc. These parameters allowed DOE to conduct a top-down cost analysis of residential boiler manufacturers, which DOE used to derive the preliminary industry financial inputs for the GRIM (*e.g.*, revenues, depreciation, SG&A, and research and development (R&D) expenses).

DOE used public information to calibrate its initial characterization of the industry, including Securities and Exchange Commission (SEC) 10-K reports,[1] Standard & Poor's (S&P) stock reports,[2] market research tools (*i.e.*, Hoover's[3]), corporate annual reports, and the U.S. Census Bureau's *2011 Annual Survey of Manufacturers*.[4] DOE also used information from its engineering analysis and the life-cycle cost analysis to enhance its industry profile.

12.2.2 Phase II: Industry Cash-Flow Analysis and Interview Guide

Phase II focused on the financial impacts of amended energy conservation standards on manufacturers of residential boilers. More stringent energy conservation standards can affect manufacturer cash flows in three distinct ways. These include: (1) creating a need for increased investment; (2) raising production costs per unit; and (3) altering revenue due to higher per-unit prices and/or possible changes in sales volumes. To quantify these impacts, DOE used the GRIM to perform a cash-flow analysis for the residential boiler industry. DOE used the financial values derived during Phase I and the shipment scenarios used in the national impact analysis (NIA) to perform these analyses. The GRIM modeled both impacts from the active mode energy conservation standards (*i.e.*, standards based on annual fuel utilization efficiency (AFUE) ratings) and impacts from standby mode and off mode energy conservation standards (*i.e.,* standards based on standby mode and off mode wattage). The GRIM results from the two standards were evaluated independent of one another. In Phase II, DOE also prepared written guides for manufacturer interviews.

12.2.2.1 Industry Cash-Flow Analysis

The GRIM is designed to take into account several factors while calculating a series of annual cash flows from the announcement year of amended energy conservation standards until 30 years after the compliance date. These factors include annual expected revenues, costs of goods sold, SG&A, taxes, and capital expenditures related to the amended standards. DOE developed these financial parameters using publicly available manufacturer data and revised them with information submitted confidentially during manufacturer interviews. DOE also used estimates developed in other analyses as inputs to the GRIM including manufacturer production costs (MPCs), markup assumptions, and shipments forecasts. DOE derived the MPCs from the engineering analysis and information provided by the industry. DOE estimated typical manufacturer markups from publicly available financial reports and interviews with manufacturers. DOE developed alternative markup scenarios for the GRIM based on discussions with manufacturers. DOE's shipments analysis, presented in chapter 9 of the TSD, provided the basis for the shipment projections in the GRIM. Once the GRIM was complete, DOE compared

the results at various TSLs to no-new-standards case projections for the industry. The difference between the discounted annual cash flows in the no-new-standards case and standards case at each TSL represents the financial impact of amended standards on the industry.

12.2.2.2 Interview Guides

During Phase II of the MIA, DOE developed an interview guide to help gather information on the effects of amended energy conservation standards on revenues and finances, direct employment, capital assets, and industry competitiveness. DOE distributed the interview guide to the companies that agreed to participate well before the interviews to give companies time to prepare responses. DOE used the interview guide to structure its conversation with manufacturers and to procure information about important manufacturing issues relevant to this rulemaking. DOE also sought to identify potential impacts that could result from amended energy conservation standards on individual manufacturers or subgroups of manufacturers. Information received from these meetings is protected by nondisclosure agreements and is stored securely by DOE's contractors. The MIA interview topics included: (1) key issues; (2) engineering; (3) company overview and organizational characteristics; (4) markups and profitability; (5) financial parameters; (6) shipment projections and market shares; (7) product mix; (8) distribution channels; (9) conversion costs; (10) cumulative regulatory burden; (11) direct employment impact assessment; (12) capacity, outsourcing, and foreign competition; (13) consolidation; and (14) impacts on small business.

12.2.3 Phase III: Subgroup Analysis

In Phase III of its analysis, DOE interviewed a wide range of residential boiler manufacturers in order to better inform its analyses and to identify any subgroups of manufacturers that may be affected in different ways by amended standards. DOE identified small manufacturers as a subgroup that could be disproportionately affected by amended standards, and as a result, DOE will conduct a separate analysis for small businesses in the industry.

12.2.3.1 Manufacturer Interviews

The information gathered in Phase I and the cash-flow analysis performed in Phase II are supplemented with information gathered from manufacturer interviews in Phase III of the MIA. The interview process provides an opportunity for interested parties to express their views on important issues confidentially, allowing sensitive information to be considered in the rulemaking process. DOE sought to understand manufacturers' key issues and concerns with this rulemaking and asked for feedback on its GRIM inputs and assumptions.

DOE used the information gained in these interviews to tailor the GRIM to more accurately reflect financial characteristics unique to the residential boiler industry. Interviews were scheduled well in advance to provide every opportunity for key individuals to be available for comment. DOE accepted written responses to the interview guide, however, made every effort to schedule interactive interviews, which helped to clarify responses and identify additional issues.

12.2.3.2 Revised Industry Cash-Flow Analysis

In Phase II of the MIA, DOE provided manufacturers with preliminary financial figures for the GRIM analysis for their review and evaluation. During the interviews, DOE requested comments on the values it had calculated for the GRIM. DOE revised its industry cash-flow model based on manufacturer feedback. Section 12.4.3 provides more information on how DOE calculated these parameters.

12.2.3.3 Manufacturer Subgroup Analysis

DOE acknowledges that using average cost assumptions to develop industry cash-flow estimates may not adequately assess different impacts of amended energy conservation standards on manufacturer subgroups. For example, small manufacturers, niche players, or manufacturers exhibiting a cost structure that largely differs from the industry average, could be more negatively affected. DOE included a series of questions about the subgroups it had identified its interview guide. DOE asked manufacturers and other interested parties to suggest what subgroups or characteristics are the most appropriate to analyze. DOE also asked manufacturers to comment on a list of companies that DOE believed comprised each subgroup.

DOE presents the industry impacts on residential boiler manufacturers as a whole in this Final Rule because most of the product classes represent the same market served by the same manufacturers. However, as noted previously, DOE identified one manufacturer subgroup in the residential boiler industry that warranted a separate impact analysis: small manufacturers. More information on DOE's small business impact analysis is detailed below.

Small business manufacturer subgroup. DOE first investigated whether small business manufacturers should be analyzed as a manufacturer subgroup. DOE used the U.S. Small Business Administration (SBA) small business size standards, effective January 22, 2014, as amended, and the North American Industry Classification System (NAICS) code, presented in Table 12.2.1, to determine whether any small entities would be affected by the rulemaking.[5] For the product classes under review, the SBA bases its small business definition on a business' total number of employees. This includes its subsidiaries and its parent companies. An aggregated business entity with fewer employees than the listed limit is considered a small business.

Table 12.2.1 SBA and NAICS Classification of Small Businesses Potentially Affected by This Rulemaking

Industry Description	Revenue Limit	Employee Limit	NAICS
Heating Equipment (except Warm Air Furnaces) Manufacturing	N/A	500	333414

DOE used publicly available and proprietary information to identify potential small manufacturers. DOE's research involved industry trade association membership directories (*e.g.,* American Heating and Refrigeration Institute (AHRI) Directory[6]), public databases *(e.g.,* California Energy Commission (CEC) Appliance Efficiency Database[7]), individual company websites, and market research tools (*e.g.*, Hoover's reports). DOE used information from these sources to create a list of companies that manufacture or sell products covered by this rulemaking. During manufacturer interviews and at previous DOE public meetings, DOE also asked stakeholders and industry representatives if they were aware of any other small

manufacturers. DOE screened out companies that did not offer products covered by this rulemaking, did not meet the definition of a small business, or are foreign owned and operated.

Based on this analysis, DOE identified 13 companies in the residential boiler industry that qualify as small businesses. Of those 13 small businesses, nine manufacture boilers covered by this rulemaking, while the other four manufacturers rebrand imported products or products manufactured by other small companies. DOE made an effort to contact all identified small businesses to solicit feedback on the potential impacts of energy conservation standards. Two of the small businesses agreed to be interviewed. In addition to posing a subset of modified MIA interview questions, DOE solicited data on different impacts these companies might experience as a result of amended energy conservation standards. DOE obtained further information on small business impacts in interviews with large manufacturers. DOE reports the results of its analysis on the potential impacts of this rulemaking on small manufacturers in section 12.6.

12.2.3.4 Manufacturing Capacity Impact

Amended energy conservation standards could result in the obsolescence of existing manufacturing assets, including tooling and capital investments. The manufacturer interview guide includes a series of questions to help identify impacts of amended standards on manufacturing capacity. Specifically, questions address: capacity utilization and plant location decisions in the United States and North America, with and without amended standards; the ability of manufacturers to upgrade or remodel existing facilities to accommodate the new efficiency requirements; the nature and value of any stranded assets that might result from amended standards; and estimates for any one-time changes to existing PPE that be necessitated by amended standards. DOE's estimates of the one-time capital changes and stranded assets affect the cash flow estimates in the GRIM. These estimates can be found in section 12.4.8. DOE's discussion of the manufacturing capacity impact can be found in section 12.7.2.

12.2.3.5 Employment Impact

The impact of amended energy conservation standards on employment is an important consideration in the rulemaking process. During manufacturer interviews, DOE solicited information about current employment trends in the residential boiler industry, as well as manufacturers' views on how amended standards might change employment patterns. In the employment impacts section of the interview guide, DOE asked manufacturers about current employment levels at their production facilities and expected future employment levels with and without amended energy conservation standards. DOE also inquired about any different workforce skills or employee retraining that might be necessary if standards were amended. The employment impacts are reported in section 12.7.1.

12.2.3.6 Cumulative Regulatory Burden

DOE seeks to mitigate the overlapping effects on manufacturers due to amended energy conservation standards and other regulatory actions affecting the same products. DOE analyzed the impact on manufacturers of multiple, product-specific regulatory actions. Based on its own research and discussions with manufacturers, DOE identified regulations relevant to residential boiler manufacturers, including other federal regulations that affect other products made by the

same manufacturers. Discussion of the cumulative regulatory burden can be found in section 12.7.3.

12.3 MANUFACTURER IMPACT ANALYSIS KEY ISSUES

Each MIA interview starts by asking: "What are the key issues for your company regarding this energy conservation standard rulemaking?" This question prompts manufacturers to identify the issues they want DOE to explore and discuss further during the interview. The following sections describe the most significant issues identified by residential boiler manufacturers. These summaries report aggregated information to protect manufacturer confidentiality.

12.3.1 Diminished Ability to Serve the Replacement Market

In interviews, several manufacturers pointed out that more than 90 percent of residential boiler sales are transacted in the replacement channel, rather than in the new construction channel. They pointed out that the current residential boiler market is structured around the legacy venting infrastructures that exist in the vast majority of homes, and any regulation that eliminated 82-83% AFUE percent efficient products would be very disruptive to the market. Manufacturers reported that in this scenario, consumers would face higher installation costs, as well as complex challenges in changing the layout of their boiler room and upgrading their venting and heat distribution systems. Manufacturers stated that these considerations may induce consumers to explore other heating, ventilating, and air conditioning options, and may cause them to leave the boiler market entirely. Manufacturers also pointed out that eliminating 82-83 percent efficient products could disrupt the market because they would have to eliminate commodity products and have to sell products for which they are less vertically integrated, which may cause them to exit the market. Some manufacturers speculated that this could result in the loss of a substantial number of American manufacturing jobs.

12.3.2 Condensing Boilers May Not Perform As Rated Without System Improvements

Several manufacturers pointed out that condensing boilers may have overstated efficiencies if they are installed in legacy systems that were designed to maintain hot water supply temperatures of 180-200 °F. Manufacturers pointed out that in these systems, return water temperatures will often be too high for condensing boilers to operate in condensing mode, thereby causing the boiler to be less efficient than its stated rating. Manufacturers also stated that because condensing boilers are designed for lower maximum supply water temperatures, the heat distribution output of the heating system as a whole is often reduced and the boiler may not be able to meet heat distribution requirements. This may require the implementation of additional heat distribution equipment within a particular system. Some manufacturers pointed out that reducing the supply water temperature also reduces the radiation component of some heat distribution units, which is essential for comfort and allows consumers to maintain a lower thermostat setting. Reducing the radiation component may require a higher thermostat setting to maintain comfort, thereby reducing overall systems efficiency.

12.3.3 Reduced Product Durability and Reliability

Several manufacturers pointed out that higher efficiency condensing boilers on the market have not demonstrated the same durability and reliability as lower efficiency products. Manufacturers noted that condensing products require more upkeep and maintenance and generally do not last as long as non-condensing products. Several manufacturers pointed out that they generally incur large after-sale costs with their condensing products because of additional warranty claims. Maintenance calls for these boilers require technicians that are more skilled, and occur more frequently than those for non-condensing boilers.

12.4 GRIM INPUTS AND ASSUMPTIONS

The Government Regulatory Impact Model serves as the main tool for assessing the impacts on industry due to amended energy conservation standards. DOE relies on several sources to obtain inputs for the GRIM. DOE then feeds data and assumptions from these sources into an accounting model that calculates the industry cash flow both with and without amended energy conservation standards.

12.4.1 Overview of the Government Regulatory Impact Model

The basic structure of the GRIM, illustrated in Figure 12.4.1, is an annual cash-flow analysis that uses manufacturer prices, manufacturing costs, shipments, and industry financial information as inputs, and accepts a set of regulatory conditions such as changes in costs, investments, and associated margins. The GRIM spreadsheet uses these and other inputs to calculate a series of annual cash flows, beginning with the base year of the analysis, 2014, and continuing to 2050. The model calculates the INPV by summing the stream of annual discounted cash flows during this period and adding a discounted terminal value.[8]

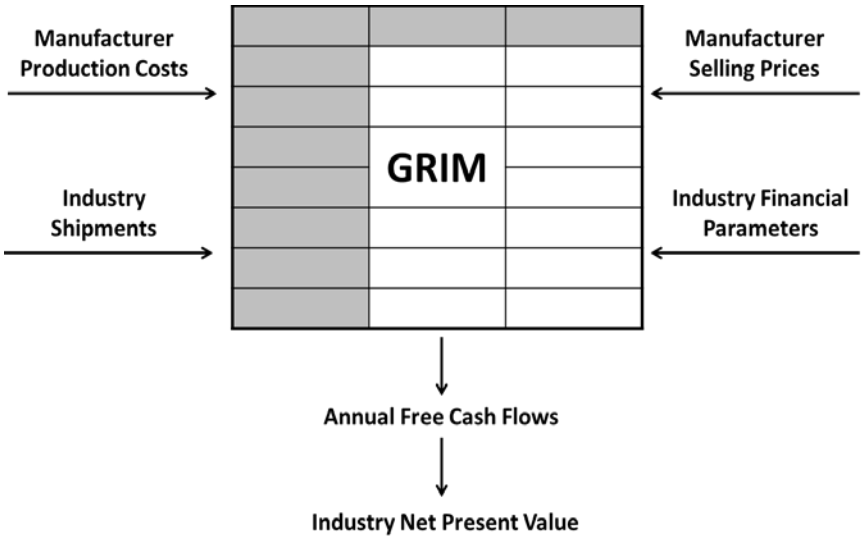

Figure 12.4.1 Using the GRIM to Calculate Cash Flow

The GRIM projects cash flows using standard accounting principles and compares changes in INPV between the no-new-standards case scenario and the standards-case scenario

induced by amended energy conservation standards. The difference in INPV between the no-new-standards case and the standards case(s) represents the estimated financial impact of amended energy conservation standards on manufacturers. Appendix 12A provides more technical details and user information for the GRIM.

12.4.2 Sources for GRIM Inputs

The GRIM uses several different sources for data inputs in determining industry cash flow. These sources include corporate annual reports, company profiles, census data, credit ratings, the shipments model, the engineering analysis, and manufacturer interviews.

12.4.2.1 Corporate Annual Reports

Corporate annual reports to the SEC (SEC 10-Ks) provided many of the initial financial inputs to the GRIM. These reports exist for publicly held companies and are available to the general public. DOE developed initial financial inputs to the GRIM by examining the annual SEC 10-K reports filed by publicly traded residential boiler manufacturers. DOE generally has to use parent-company-level financial data to develop its initial financial parameter estimates for the GRIM, as these companies do not usually provide detailed financial information about their individual product lines in their 10-K reports. These estimates were later revised using feedback from interviews to make them more representative of residential boiler manufacturing. DOE used corporate annual reports to derive the following initial inputs to the GRIM:

- tax rate
- working capital
- SG&A
- R&D
- depreciation
- capital expenditures
- net PPE

12.4.2.2 Standard and Poor Credit Ratings

S&P provides independent credit ratings, research, and financial information. DOE relied on S&P reports to determine the industry's average cost of debt when calculating the cost of capital.

12.4.2.3 Shipment Model

DOE used shipment projections derived from DOE's shipments model in the NIA in the GRIM analysis. Chapter 9 of the TSD describes the methodology and analytical model DOE used to forecast shipments.

12.4.2.4 Engineering Analysis

The engineering analysis estimates the cost-efficiency relationship of products at different levels of increased energy efficiency. This relationship serves as the basis for the cost-

benefit calculations for consumers, manufacturers, and the nation. In determining the cost-efficiency relationship, DOE estimates the increase in manufacturing costs associated with increasing the efficiency of equipment above the baseline up to the maximum technologically feasible (max tech) efficiency level for each equipment class.

DOE conducted the engineering analyses for residential boiler industry using the reverse-engineering approach.[a] DOE began its analysis by conducting industry research to select equipment classes for direct analysis, develop baseline unit specifications, and identify representative equipment for further analysis. Next, DOE selected efficiency levels based on a review of industry standards and equipment available on the market. To develop cost estimates, DOE conducted a teardown analysis, based upon physical and virtual teardowns of selected units. DOE then developed a cost model to determine manufacturing production costs. By applying derived manufacturer markups to the MPCs, DOE calculated the manufacturer selling price (MSP) and constructed industry cost-efficiency curves. See chapter 5 of the TSD for a complete discussion of the engineering analysis.

12.4.2.5 Manufacturer Interviews

During the course of the MIA, DOE interviewed manufacturers representing approximately 55 percent of the industry by revenue. The information gathered during these interviews enabled DOE to tailor the GRIM to reflect the unique financial characteristics of the residential boiler industry. In interviews, DOE asked manufacturers to describe their major concerns about this rulemaking. Key topics discussed during the interviews and reflected in the GRIM include:

- capital conversion costs (one-time investments in PPE);
- product conversion costs (one-time investments in research, product development, testing, and marketing);
- product cost structure, or the portion of the MPCs related to materials, labor, overhead, and depreciation costs;
- MPCs estimated in the engineering analysis; and
- possible profitability impacts.

12.4.3 Financial Parameters

Table 12.4.1 provides financial parameters for three public companies engaged in manufacturing and selling residential boilers. The values listed are averages over a 5-year period (2008 to 2012).

[a] DOE has identified three basic methods for generating manufacturing costs: (1) the design-option approach, which provides the incremental costs of adding to a baseline model design options that will improve its efficiency (*i.e.*, lower its energy use); (2) the efficiency-level approach, which provides the incremental costs of moving to higher energy efficiency levels, without regard to the particular design option(s) used to achieve such increases; and (3) the reverse-engineering (or cost-assessment) approach, which provides "bottom-up" manufacturing cost assessments for achieving various levels of increased efficiency based on teardown analyses (or physical teardowns) that provides detailed data on costs for parts and material, labor, shipping/packaging, and investment for models that operate at particular efficiency levels.

Table 12.4.1 Financial Parameters Used for GRIM Analysis (Based on 2008–2012 Weighted Company Financial Data)

Parameter	Industry-Weighted Average	Manufacturer		
		A	B	C
Tax Rate (% of Taxable Income)	31.5	22.2	14.8	25.4
Working Capital (% of Revenue)	22.8	27.1	21.4	22.3
SG&A (% of Revenue)	20.3	21.6	20.0	18.0
R&D (% of Revenues)	1.6	2.4	1.3	n/a
Depreciation (% of Revenues)	2.1	2.7	1.8	2.3
Capital Expenditures (% of Revenues)	2.4	3.3	2.1	1.5
Net Property, Plant, and Equipment (% of Revenues)	14.7	20.1	12.5	24.2

While most of these companies also manufacture products not covered by this rulemaking, DOE used these parameters as initial estimates. During interviews, manufacturers were asked to provide their own figures for the parameters listed in Table 12.4.1. Where applicable, DOE adjusted the parameters in the GRIM using manufacturer feedback and market share information.

DOE also used financial information from SEC filings for these three public manufacturers to determine an average manufacturer markup for the residential boiler industry.

Table 12.4.2 Financial Parameters Used to Determine No-New-Standards Case Markup

	Manufacturer		
Parameter	**A**	**B**	**C**
Average Net Revenues (Million)	$1,593	$4,745	$200.6
Corporate Gross Margin	30%	29%	23%
Markup	1.42	1.41	1.30

Table 12.4.2 lists the average net revenues, estimated corporate gross margin, and estimated manufacturer markup for 2008 to 2012 for the three manufacturers. The weighted average of the estimated manufacturer markup based on public filings by these three companies is 1.41. To further refine the no-new-standards case markup, DOE solicited feedback from manufacturers on this value in confidential interviews. Based on manufacturer feedback, DOE estimated a no-new-standards case manufacturer markup of 1.41 for all product classes.

12.4.4 Corporate Discount Rate

DOE used the weighted-average cost of capital (WACC) as the discount rate to calculate the INPV. A company's assets are financed by a combination of debt and equity. The WACC is the total cost of debt and equity weighted by their respective proportions in the capital structure of the industry. DOE estimated the WACC for the residential boilers industry based on three representative companies, using the following formula:

$$WACC = After\text{-}Tax\ Cost\ of\ Debt \times (Debt\ Ratio) + Cost\ of\ Equity \times (Equity\ Ratio)$$

The cost of equity is the rate of return that equity investors (including, potentially, the company) expect to earn on a company's stock. These expectations are reflected in the market price of the company's stock. The Capital Asset Pricing Model (CAPM) provides one widely used means to estimate the cost of equity. According to the CAPM, the cost of equity (expected return) is:

$$Cost\ of\ Equity = Riskless\ Rate\ of\ Return + \beta \times Risk\ Premium$$

Where:

Riskless Rate of Return = the rate of return on a "safe" benchmark investment, typically considered the short-term Treasury Bill (T-Bill) yield,
Risk Premium = the difference between the expected return on stocks and the riskless rate, and
Beta (β) = the correlation between the movement in the price of the stock and that of the broader market. In this case, Beta equals one if the stock is perfectly correlated with the S&P 500 market index. A Beta lower than one means the stock is less volatile than the market index.

DOE calculated that the industry average cost of equity for the residential boiler industry is 13.2 percent (Table 12.4.3).

Table 12.4.3 Cost of Equity Calculation

Parameter	Industry Weighted Average	Manufacturer		
		A	B	C
(1) Average Beta	1.43	1.06	1.60	0.36
(2) Average Yield on 10-Year Bonds (1928-2012)	5.16%			
(3) Market Risk Premium	6.10%			
Cost of Equity (2)+[(1)*(3)]	13.9%	11.7%	14.9%	7.3%
Equity/Total Capital	65.4%	84.1%	58.0%	90.0%

Bond ratings are a tool to measure default risk and arrive at a cost of debt. Each bond rating is associated with a particular spread. One way of estimating a company's cost of debt is to treat it as a spread (usually expressed in basis points) over the risk-free rate. DOE used this method to calculate the cost of debt for three public manufacturers by using S&P ratings and estimated credit worthiness and adding the relevant spread to the risk-free rate.

In practice, investors use a variety of different maturity U.S. Treasury bonds to estimate the risk-free rate. DOE used the 10-year Treasury bond rate because it captures long-term inflation expectations and is less volatile than short-term rates. The risk-free rate is estimated to be approximately 5.16 percent, which is the average 10-year Treasury bond rate between 1928 and 2012.

For the cost of debt, DOE used bond ratings from S&P's credit services to calculate an average spread of corporate bonds. DOE added these spreads to the estimated risk-free rate of 5.16 percent to determine the gross cost of debt for each company. It then calculated an industry weighted average gross cost of debt of 10.07 percent. Because proceeds from debt issuance are tax deductible, DOE adjusted the gross cost of debt by the industry average tax rate to determine the net cost of debt for the industry. Table 12.4.4 presents the derivation of the cost of debt and the capital structure of the industry (*i.e.*, the debt ratio (debt/total capital)).

Table 12.4.4 Cost of Debt Calculation

Parameter	Industry Weighted Average	Manufacturer		
		A	B	C
S&P Bond Rating		CCC	BB+	CCC
(1) Avg. Yield on 10-Yr Bonds (1928-2012)	5.16%			
(2) Gross Cost of Debt	10.07%	13.16%	8.91%	13.16%
(3) Tax Rate	31.50%	31.05%	22.26%	35.50%
Net Cost of Debt (2) x [1-(3)]	6.9%	9.1%	6.9%	8.5%
Debt/Total Capital	34.6%	15.9%	42.0%	10.0%

Using public information for these three companies, the initial estimate for the industry's nominal WACC was approximately 11.5 percent. Subtracting an inflation rate of 3.08 percent over the analysis period used in the initial estimate, the inflation-adjusted WACC and the initial estimate of the discount rate used in the strawman GRIM is 8.40 percent. DOE also asked for feedback on the discount rate during manufacturer interviews. Based on this feedback, DOE used a discount rate of 8.40 percent in the GRIM.

12.4.5 Trial Standard Levels

DOE developed a number of efficiency levels for each type of product class. TSLs were then developed by selecting likely groupings of efficiency levels for all product types. Table 12.4.5 presents the TSLs used for energy efficiency analysis in the GRIM.

Table 12.4.5 Summary of Active-Mode TSLs for the Residential Boiler Industry

Product Class	TSL 1	TSL 2	TSL 3	TSL 4	TSL 5
	Efficiency Level				
Gas-Fired Hot Water Boilers	1	1	2	4	6
Gas-Fired Steam Boilers	1	1	1	1	2
Oil-Fired Hot Water Boilers	1	2	2	3	3
Oil-Fired Steam Boilers	1	1	2	3	3

Table 12.4.6 Summary of Standby/Off-Mode TSLs for the Residential Boiler Industry

Product Class	TSL 1	TSL 2	TSL 3
	Efficiency Level		
Gas-Fired Hot Water Boilers	1	2	3
Gas-Fired Steam Boilers	1	2	3
Oil-Fired Hot Water Boilers	1	2	3
Oil-Fired Steam Boilers	1	2	3
Electric Hot Water Boilers	1	2	3

12.4.6 National Impact Analysis Shipments

The GRIM estimates manufacturer revenues based on total unit shipment forecasts and the distribution of these values by efficiency level. Changes in sales volumes and efficiency mix over time can significantly affect manufacturer finances. For this analysis, the GRIM uses the NIA's annual shipment forecasts derived from the shipments analysis from 2014 (the base year) to 2050 (the end year of the analysis period). The shipments model divides the shipments of residential boilers into specific market segments. The model starts from a historical base year and calculates retirements and shipments by market segment for each year of the analysis period. This approach produces an estimate of the total product stock, broken down by age or vintage, in each year of the analysis period. In addition, the product stock efficiency distribution is calculated for the no-new-standards case and for each standards case for each product class. The NIA shipments forecasts are, in part, based on a roll-up scenario. The forecast assumes that a product in the no-new-standards case that does not meet the standard under consideration would "roll up" to meet the amended standard beginning in the compliance year of 2021. See chapter 9 of the TSD for more information on the standards-case shipment forecasts.

12.4.7 Manufacturer Production Costs

Manufacturing a higher efficiency product is typically more expensive than manufacturing a baseline product due to the use of more complex components, which are typically more costly than baseline components. The changes in the MPCs of the analyzed products can affect the revenues, gross margins, and cash flow of the industry, making these product cost data key GRIM inputs for DOE's analysis.

In the MIA, DOE used the MPCs for each considered efficiency level calculated in the engineering analysis, as described in chapter 5 of the Final Rule TSD. In addition, DOE used information from its teardown analysis (also described in chapter 5 of the TSD) to disaggregate the MPCs into material, labor, and overhead costs. To calculate the MPCs for products at and above the baseline, DOE performed teardowns and cost modeling that allowed DOE to estimate the incremental material, labor, and overhead costs for products above the baseline. DOE validated and revised these cost breakdowns and product markups with manufacturers during manufacturer interviews.

To calculate the baseline manufacturer selling price, DOE used the MPCs from the engineering and teardown analyses and applied a manufacturer markup, which varies with the markup scenario (discussed in detail in section 12.4.9), to the MPCs.

To develop MPCs for the standby and off mode TSLs, DOE used the same baseline MPCs used in the active mode analysis and added the incremental costs derived in the engineering analysis necessary to achieve each respective efficiency level to the materials cost of the product. The incremental costs were determined as part of the teardown analysis detailed in chapter 5 of the Final Rule TSD.

Table 12.4.7 through Table 12.4.14 show the production cost estimates used in the GRIM for each analyzed equipment class in the active mode and standby and off mode analyses.

Table 12.4.7 Manufacturer Production Cost Breakdown (2014$) for Gas-Fired Hot Water Boilers (Active Mode)

Efficiency Level	Material $	Labor $	Depreciation $	Overhead $	MPC $	Markup	MSP $
Baseline	468.29	63.32	25.08	70.21	626.90	1.41	883.93
1	474.61	64.09	24.75	71.06	634.51	1.41	894.66
2	480.30	64.85	25.04	71.92	642.12	1.41	905.39
3	507.90	69.75	22.35	77.20	677.20	1.41	954.86
4	827.88	64.62	26.25	90.86	1,009.61	1.41	1,423.55
5	976.03	81.43	28.33	94.42	1,180.21	1.41	1,664.10
6	1,282.62	83.39	31.84	118.26	1,516.10	1.41	2,137.70

Table 12.4.8 Manufacturer Production Cost Breakdown (2014$) for Gas-Fired Hot Water Boilers (Standby and Off Mode)

Efficiency Level	Material $	Labor $	Depreciation $	Overhead $	MPC $	Markup	MSP $
Baseline	626.90	63.32	25.08	70.21	785.51	1.41	1,107.56
1	637.30	63.32	25.08	70.21	795.91	1.41	1,122.23
2	645.43	63.32	25.08	70.21	804.04	1.41	1,133.69
3	645.92	63.32	25.08	70.21	804.53	1.41	1,134.38

Table 12.4.9 Manufacturer Production Cost Breakdown (2014$) for Gas-Fired Steam Boilers (Active Mode)

Efficiency Level	Material $	Labor $	Depreciation $	Overhead $	MPC $	Markup	MSP $
Baseline	590.63	82.49	25.68	79.37	778.16	1.41	1,097.21
1	602.18	84.10	25.39	81.72	793.38	1.41	1,118.67
2	732.44	85.08	24.04	83.23	924.80	1.41	1,303.97

Table 12.4.10 Manufacturer Production Cost Breakdown (2014$) for Gas-Fired Steam Boilers (Standby and Off Mode)

Efficiency Level	Material $	Labor $	Depreciation $	Overhead $	MPC $	Markup	MSP $
Baseline	778.16	82.49	25.68	79.37	965.70	1.41	1,361.64
1	788.56	82.49	25.68	79.37	976.10	1.41	1,376.30
2	796.69	82.49	25.68	79.37	984.23	1.41	1,387.76
3	797.18	82.49	25.68	79.37	984.72	1.41	1,388.45

Table 12.4.11 Manufacturer Production Cost Breakdown (2014$) for Oil-Fired Hot Water Boilers (Active Mode)

Efficiency Level	Material $	Labor $	Depreciation $	Overhead $	MPC $	Markup	MSP $
Baseline	968.73	88.40	42.97	127.69	1,227.79	1.41	1,731.18
1	1,031.54	96.38	42.98	131.55	1,302.45	1.41	1,836.45
2	1,094.80	100.53	42.69	139.09	1,377.11	1.41	1,941.73
3	1,823.69	203.66	69.43	217.55	2,314.33	1.41	3,263.20

Table 12.4.12 Manufacturer Production Cost Breakdown (2014$) for Oil-Fired Hot Water Boilers (Standby and Off Mode)

Efficiency Level	Material $	Labor $	Depreciation $	Overhead $	MPC $	Markup	MSP $
Baseline	1,227.79	88.40	42.97	127.69	1,486.85	1.41	2,096.46
1	1,238.19	88.40	42.97	127.69	1,497.25	1.41	2,111.13
2	1,246.32	88.40	42.97	127.69	1,505.38	1.41	2,122.59
3	1,246.81	88.40	42.97	127.69	1,505.87	1.41	2,123.28

Table 12.4.13 Manufacturer Production Cost Breakdown (2014$) for Oil-Fired Steam Boilers (Active Mode)

Efficiency Level	Material $	Labor $	Depreciation $	Overhead $	MPC $	Markup	MSP $
Baseline	983.68	96.37	41.30	130.16	1,251.50	1.41	1,764.62
1	1,112.25	106.46	43.43	138.68	1,400.82	1.41	1,975.16
2	1,175.96	110.66	44.26	144.60	1,475.48	1.41	2,080.43
3	1,304.71	118.61	43.87	157.61	1,624.80	1.41	2,290.97

Table 12.4.14 Manufacturer Production Cost Breakdown (2014$) for Oil-Fired Steam Boilers (Standby and Off Mode)

Efficiency Level	Material $	Labor $	Depreciation $	Overhead $	MPC $	Markup	MSP $
Baseline	1,251.50	96.37	41.30	130.16	1,519.32	1.41	2,142.24
1	1,261.90	96.37	41.30	130.16	1,529.72	1.41	2,156.91
2	1,270.03	96.37	41.30	130.16	1,537.85	1.41	2,168.37
3	1,270.52	96.37	41.30	130.16	1,538.34	1.41	2,169.06

12.4.8 Capital and Product Conversion Costs

Amended energy conservation standards typically cause manufacturers to incur one-time conversion costs to bring their production facilities and product designs into compliance with new regulations. For the MIA, DOE classified these one-time conversion costs into two major groups: capital conversion costs and product conversion costs. Capital conversion costs are one-time investments in property, plant, and equipment to adapt or change existing production facilities to fabricate and assemble new product designs that comply with amended energy conservation standards. Product conversion costs are one-time investments in research, development, and industry certification testing to make product designs comply with amended energy conservation standards, as well as other non-capital costs, such as marketing. DOE based its estimates of the conversion costs for each efficiency level on information obtained from manufacturer interviews and the design pathways analyzed in the engineering analysis.

To evaluate the level of capital conversion expenditures manufacturers would likely incur to comply with amended energy conservation standards, DOE used manufacturer interviews to gather data on the anticipated level of capital investment that would be required at each efficiency level. For efficiency levels where manufacturers would not use condensing heat exchangers to improve efficiency, DOE does not expect that manufacturers will incur substantial capital conversion costs. For these efficiency levels, DOE developed a per-manufacturer market-share-weighted average capital expenditure for each product class based on manufacturer feedback in interviews. DOE then multiplied these weighted average figures by the number of manufacturers that offer each product class to reach final capital conversion costs estimates at these efficiency levels.

For efficiency levels where manufacturers stated they would use condensing technology to meet the higher standards for gas-fired hot water boilers, most manufacturers said that they would have to decide whether to continue to source condensing heat exchangers from Europe or Asia, or develop their own domestic production capacity. Nearly all manufacturers in the United States that currently offer condensing products source the heat exchanger from Europe or Asia; however, a few are in the process of developing their own production capacity. In modeling its capital conversion cost estimates, DOE made assumptions about which manufacturers would develop their own condensing heat exchanger production lines. During interviews, several manufacturers indicated that production of heat exchangers is an important part of the value chain. If standards were set at efficiency levels where manufacturers would use condensing technology in their gas-fired hot water boilers, several said that in the long run, they would likely consider producing condensing heat exchangers in house, rather than continue source them. DOE estimated if standards were set at TSL 4 or higher, five large manufacturers in the United States would make this investment, as they have easier access to capital and extensive engineering resources, compared to some smaller manufacturers. Manufacturers stated that developing this capacity would be important for them to remain relatively vertically integrated, rather than assembling their products around a sourced heat exchanger. DOE supplemented manufacturer comments and tailored its analyses with estimates of capital expenditure requirements derived from the product teardown analysis and engineering analysis described in chapter 5 of the TSD.

DOE assessed the product conversion costs at each considered efficiency level by integrating data from quantitative and qualitative sources. DOE considered market-share-weighted feedback regarding the potential costs of each efficiency level from multiple manufacturers to estimate product conversion costs, and validated those numbers against engineering estimates of redesign efforts. DOE combined this information with product listings from AHRI to estimate how much manufacturers would have to spend on product development and product testing at each efficiency level. When analyzing efficiency levels at which manufacturers would use condensing heat exchangers to achieve the prescribed standards, DOE made the same assumptions about certain manufacturers developing their own production capacity for condensing heat exchangers, rather than continuing to source them. In interviews, manufacturers stated theses higher efficiency products would require more complex components and controls, knowledge about different metals, and a more high-tech and complex production process. They pointed out that a large engineering effort would be required to design new products and production processes. For these efficiency levels, DOE assumed that the same five manufacturers would incur large product conversion costs to develop their own condensing heat exchanger production capacity. Other manufacturers would also incur relatively high product

conversion costs in order to design a baseline product around a condensing heat exchanger for gas-fired hot water products.

DOE's estimates of the product and capital conversion costs for each product class can be found in Table 12.4.15 through Table 12.4.18 below. Table 12.4.19 summarizes the conversion costs for all residential boilers.

Table 12.4.15 Industry Product and Capital Conversion Costs for Gas-Fired Hot Water Boilers

TSL	Product Conversion Costs *(2014$ millions)*	Capital Conversion Cost *(2014$ millions)*
Baseline	0	0
1	0.88	0
2	0.88	0
3	0.91	0.18
4	10.76	58.64
5	20.37	66.80

Table 12.4.16 Industry Product and Capital Conversion Costs for Gas-Fired Steam Boilers

TSL	Product Conversion Costs *(2014$ millions)*	Capital Conversion Cost *(2014$ millions)*
Baseline	0	0
1	0.25	0
2	0.25	0
3	0.25	0
4	0.25	0
5	3.30	0.25

Table 12.4.17 Industry Product and Capital Conversion Costs for Oil-Fired Hot Water Boilers

TSL	Product Conversion Costs *(2014$ millions)*	Capital Conversion Cost *(2014$ millions)*
Baseline	0	0
1	0.17	0
2	0.43	0.43
3	0.43	0.43
4	13.39	2.16
5	13.39	2.16

Table 12.4.18 Industry Product and Capital Conversion Costs for Oil-Fired Steam Boilers

TSL	Product Conversion Costs *(2014$ millions)*	Capital Conversion Cost *(2014$ millions)*
Baseline	0	0
1	0.03	0
2	0.03	0
3	0.06	0
4	0.12	0.30
5	0.12	0.30

Table 12.4.19 Industry Product and Capital Conversion All Residential Boilers

TSL	Product Conversion Costs *(2014$ millions)*	Capital Conversion Cost *(2014$ millions)*	Total Conversion Costs *(2014$ millions)*
Baseline	0	0	0
1	1.34	0	1.34
2	1.60	0.43	2.03
3	1.66	0.61	2.27
4	24.53	61.10	85.63
5	37.19	69.52	106.71

DOE does not expect significant capital and product conversion costs to be associated with the standby and off mode standards relative to the size of the active mode standards proposed in the Final Rule. DOE estimates that manufacturers will not incur any capital conversion costs, as compliance with these standards will require manufacturers to integrate a purchase part into their residential boiler products and will not result in any changes to production processes. DOE estimates that manufacturers would incur $0.21 million in product conversion costs, primarily for testing. DOE estimated product conversion costs based on product testing cost quotations and on market information about the number product families offered by each manufacturer.

12.4.9 Markup Scenarios

DOE modeled two markup scenarios to capture uncertainty regarding potential impacts on prices and profitability following implementation of amended energy conservation standards: (1) a preservation of gross margin percentage markup scenario and (2) a preservation of per-unit operating profit markup scenario. These scenarios lead to different markup values that, when applied to MPCs, result in varying revenue and cash flow impacts. DOE used the same markup scenarios in both the active and the standby/off mode analyses.

12.4.9.1 Preservation of Gross Margin Percentage Scenario

Under the preservation of gross margin percentage scenario, DOE applied a single uniform “gross margin percentage” markup across all efficiency levels. This assumes manufacturers would be able to maintain the same amount of profit, as a percentage of revenues, at all efficiency levels within a product class. As production costs and sales prices increase with more stringent efficiency levels, this scenario implies that the absolute dollar markup will increase as well. The manufacturer, in this case, will see more profit in absolute terms on a per-unit basis. In analyzing the preservation of gross margin percentage scenario, DOE assumed the

average non-production cost markup—which includes SG&A expenses, R&D expenses, interest, and profit— to be 1.41 for all residential boiler product classes.

Because this markup scenario implies manufacturers would be able to maintain their gross margin percentage markups as production costs increase in response to amended energy conservation standards, DOE assumes this scenario represents an upper bound to industry profitability under amended standards.

12.4.9.2 Preservation of Per Unit Operating Profit Scenario

DOE decided to include the preservation of per unit operating profit scenario in its analysis because manufacturers stated that they do not expect to be able to mark up the full cost of production in the standards case, given the highly competitive nature of the residential boiler market. In this scenario, manufacturer markups are set so that operating profit one year after the compliance date of amended energy conservation standards is the same as in the no-new-standards case on a per unit basis. In other words, manufacturers are not able to yield additional operating profit from the higher production costs and the investments that are required to comply with the proposed standards; however, they are able to maintain the same operating profit in the standards case that was earned in the no-new-standards case. Therefore, operating margin in percentage terms is reduced between the no-new-standards case and standards case. DOE adjusted the manufacturer markups in the GRIM at each TSL to yield approximately the same earnings before interest and taxes in the standards case as in the no-new-standards case. The preservation of per unit operating profit markup scenario represents the lower bound of industry profitability in the standards case. This is because manufacturers are not able to fully pass through to consumers the additional costs necessitated by residential boiler standards, as they are able to do in the preservation of gross margin percentage markup scenario.

12.5 INDUSTRY FINANCIAL IMPACTS

Using the inputs and scenarios described in previous sections, DOE estimated financial impacts on the residential boiler industry resulting from amended energy conservation standards. The following sections address two key financial metrics analyzed in the MIA: industry net present value and annual cash flows.

12.5.1 Impacts on Industry Net Present Value

The INPV measures the industry value and is used in the MIA to compare the economic impacts of different TSLs. The INPV is different from DOE's net present value, which is applied to the U.S. economy. The INPV is the sum of all net cash flows discounted at the industry's cost of capital or discount rate. The GRIM for this rulemaking estimates cash flows from 2014 to 2049. This timeframe models both the short-term impacts on the industry from the base year of the analysis until the compliance date (2014–2021) and the long-term impacts over the 30-year analysis period used in the NIA (2021–2050).

In the MIA, DOE compares the INPV in the no-new-standards case (no amended energy conservation standards) to the INPVs that result at each TSL in the standards case. The difference between these estimates represents the economic impacts implementing a particular

TSL would have on the industry. For the residential boiler industry, DOE examined the two markup scenarios described in section 12.4.9, which will result in a range of INPV results at each TSL.

Standby mode and off mode standards results are also analyzed and are presented in Table 12.5.3 and Table 12.5.4. The impacts of standby mode and off mode features were analyzed for the same product classes as the amended AFUE standards, but at different efficiency levels, which correspond to a different set of technology options for reducing standby mode and off mode energy consumption. Therefore, the TSLs in the standby mode and off mode analysis do not correspond to the TSLs in the AFUE analysis. Also, the electric boiler product classes were not analyzed in the GRIM for AFUE standards. As a result, quantitative numbers for this product class are not available in the GRIM. However, the standby mode and off mode technology options considered for electric boilers are identical to the technology options for all other residential boiler product classes. Consequently, DOE expects the standby mode and off mode impacts on electric boilers to be of the same order of magnitude as the impacts on all other boiler product classes.

The impacts of standby mode and off mode features were analyzed for the same two markup scenarios to represent the upper and lower bounds of industry impacts for residential boilers that were used in the AFUE analysis: (1) a preservation of gross margin percentage scenario; and (2) a preservation of per-unit operating profit scenario. As with the AFUE analysis, the preservation of gross margin percentage represents the lower bound of impacts, while the preservation of per-unit operating profit scenario represents the upper bound of impacts.

Table 12.5.1 and Table 12.5.2 show the INPV results from the active mode analysis. Table 12.5.3 and Table 12.5.4 show the INPV results from the standby/off mode analysis.

Table 12.5.1 Changes in INPV for the Residential Boiler Industry, 2014-2050 -- Preservation of Gross Margin Percentage Scenario (Active Mode)*

	Units	No-New-Standards Case	Trial Standard Level				
			1	2	3	4	5
INPV	2014$ M	367.83	367.50	368.69	369.45	349.47	366.71
Change in INPV	2014$ M	-	(0.33)	0.86	1.62	(18.35)	(1.12)
	(%)	-	(0.09)	0.24	0.44	(4.99)	(0.30)

* Numbers in parentheses indicate negative numbers.

Table 12.5.2 Changes in INPV for the Residential Boiler Industry, 2014-2050 -- Preservation of Per Unit Operating Profit Scenario (Active Mode)*

	Units	No-New-Standards Case	Trial Standard Level				
			1	2	3	4	5
INPV	2014$ M	367.83	365.70	364.94	365.20	284.21	225.88
Change in INPV	2014$ M	-	(2.12)	(2.89)	(2.63)	(83.61)	(141.95)
	(%)	-	(0.58)	(0.79)	(0.71)	(22.73)	(38.59)

* Numbers in parentheses indicate negative numbers.

Table 12.5.3 Changes in INPV for the Residential Boiler Industry, 2014-2050 -- Preservation of Gross Margin Percentage Scenario (Standby/Off Mode)*

	Units	No-New-Standards Case	Trial Standard Level		
			1	2	3
INPV	2014$ M	367.83	367.73	367.74	368.28
Change in INPV	2014$ M	-	(0.10)	(0.09)	0.45
	(%)	-	(0.03)	(0.02)	0.12

* Numbers in parentheses indicate negative numbers.

Table 12.5.4 Changes in INPV for the Residential Boiler Industry, 2014-2050 -- Preservation of Per Unit Operating Profit Scenario (Standby/Off Mode)

	Units	No-New-Standards Case	Trial Standard Level		
			1	2	3
INPV	2014$ M	367.83	367.61	367.78	366.12
Change in INPV	2014$ M	-	(0.22)	(0.04)	(1.71)
	(%)	-	(0.06)	(0.01)	(0.46)

* Numbers in parentheses indicate negative numbers.

12.5.2 Impacts on Annual Cash Flow

While INPV is useful for evaluating the long-term effects of amended energy conservation standards, short-term changes in cash flow are also important indicators of the industry's financial situation. For example, a large investment over one or two years could strain the industry's access to capital. Consequently, a sharp drop in financial performance could cause investors to flee, even though recovery may be possible. Thus, a short-term disturbance can have long-term effects that the INPV cannot capture. To illustrate this possible short-term disturbance, shown in Figure 12.5.1 through Figure 12.5.4, present annual net cash flows from 2014 through 2027 for the no-new-standards case and different TSLs in the standards case.

Annual cash flows are discounted to the base year, 2014. After the standards announcement date (2015), industry cash flows begin to decline as companies use their financial resources to prepare for compliance with amended energy conservation standard. Cash flows between the announcement date and the compliance date are driven by the level of conversion costs and the proportion of these investments spent each year. The more stringent the amended energy conservation standard, the greater the impact on industry cash flows in the years leading up to the compliance date, as product conversion costs lower cash inflows from operations and capital conversion costs increase cash outflows for capital expenditures.

Free cash flow in the year the amended energy conservation standards take effect is driven by two competing factors. In addition to capital and product conversion costs, amended energy conservation standards could create stranded assets, *i.e.*, tooling and equipment that could have been used longer if the energy conservation standards had not made them obsolete. In this year, manufacturers write down the remaining book value of existing tooling and equipment whose value is affected by the amended standards. This one-time write-down acts as a tax shield that alleviates decreases in cash flow from operations in the year of the write-down. In this year, there is also an increase in working capital that reduces cash flow from operations. A large increase in working capital is needed due to more costly production components and materials,

carrying higher inventory to sell more expensive products, and higher accounts receivable for more expensive products. Depending on these two competing factors, cash flow can be affected either positively or negatively in the year the standard takes effect.

As noted above, the impacts of standby mode and off mode features were analyzed for the same product classes as the amended AFUE standards, but at different efficiency levels, which correspond to a different set of technology options for reducing standby mode and off mode energy consumption.

As previously noted, DOE analyzed AFUE standards for residential boilers in active mode separately from standby mode and off mode features. These features were analyzed for the same product classes, but at efficiency levels that correspond to a different set of technology options for reducing standby mode and off mode energy consumption. Figure 12.5.1 and Figure 12.5.2 graph the net annual cash flows for the two markup scenarios for the active mode analysis. Figure 12.5.3 and Figure 12.5.4 graph the net annual cash flow for the two scenarios for the standby/off mode analysis.

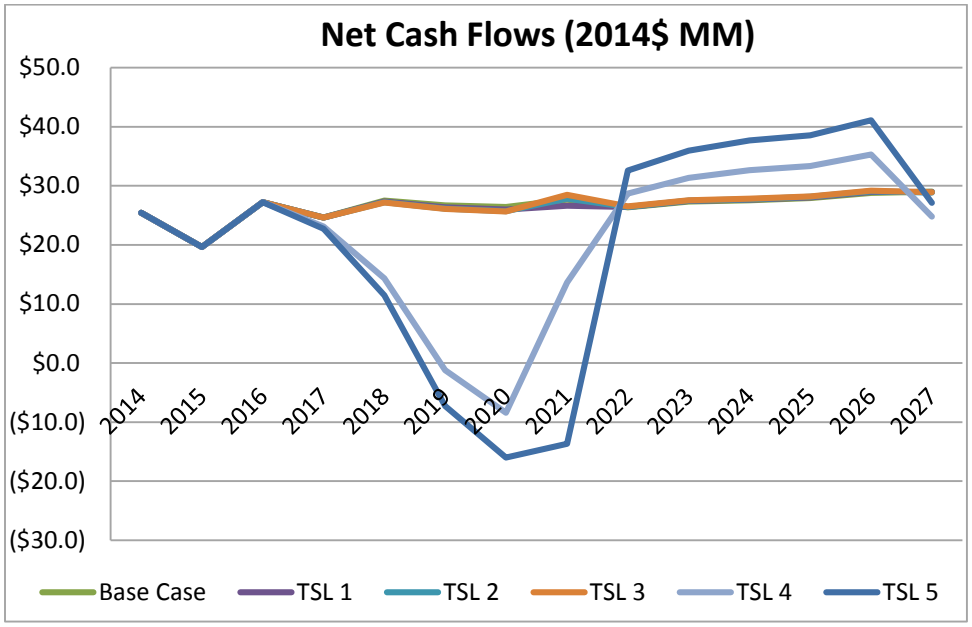

Figure 12.5.1 Annual Industry Net Cash Flows for the Residential Boiler Industry -- Preservation of Gross Margin Scenario (Active Mode)

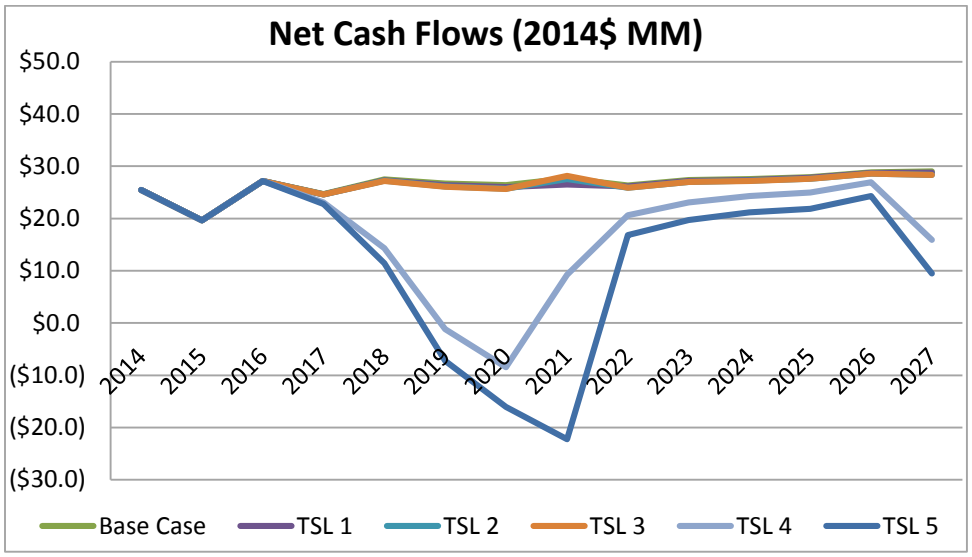

Figure 12.5.2 Annual Industry Net Cash Flows for the Residential Boiler Industry -- Preservation of Per Unit Operating Profit Scenario (Active Mode)

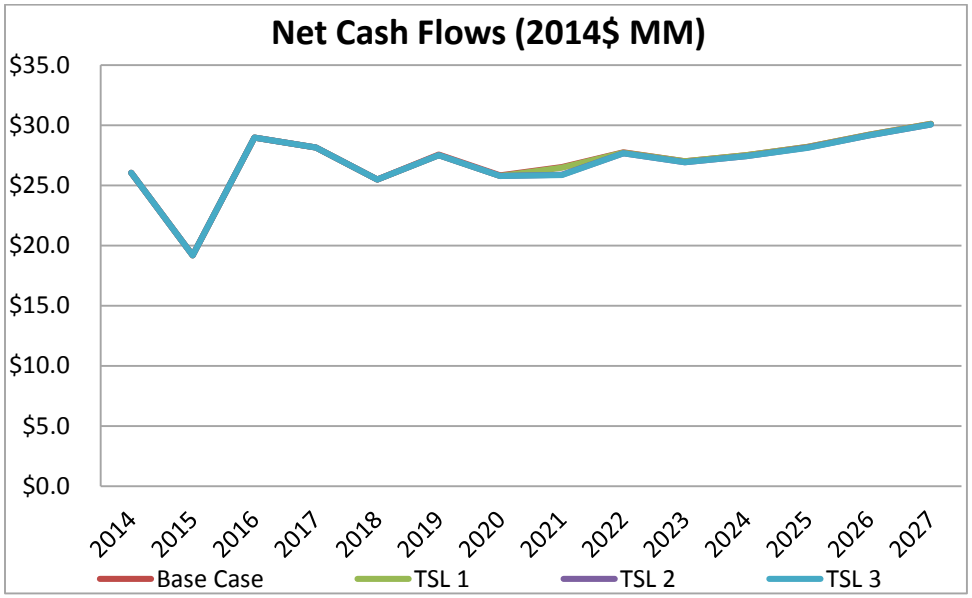

Figure 12.5.3 Annual Industry Net Cash Flows for the Residential Boiler Industry -- Preservation of Gross Margin Percentage Scenario (Standby/Off)

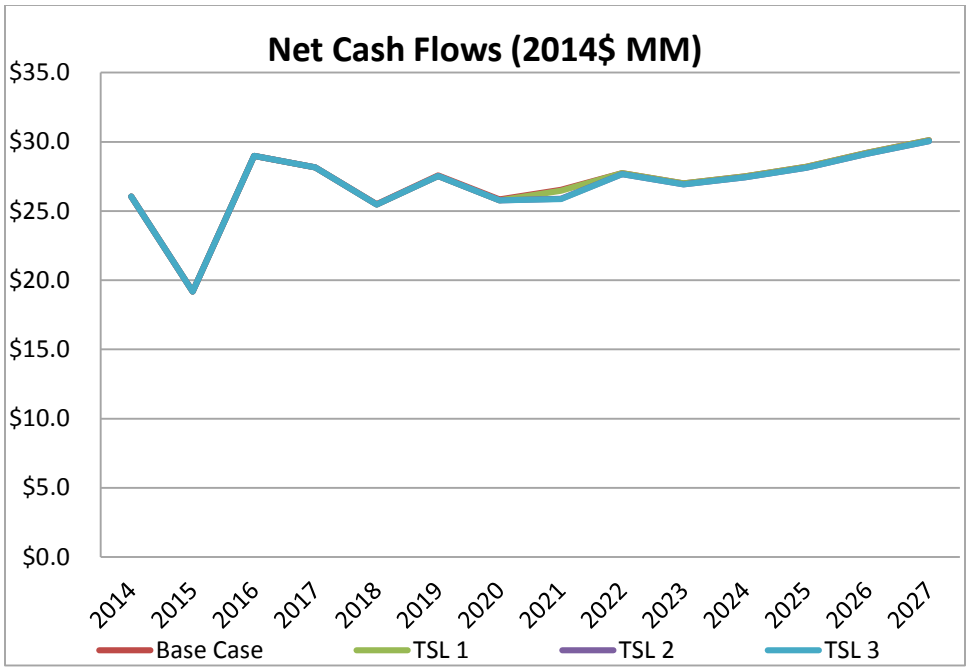

Figure 12.5.4 Annual Industry Net Cash Flows for the Residential Boiler Industry -- Preservation of Per Unit Operating Profit Scenario (Standby/Off Mode)

12.6 IMPACTS ON SMALL BUSINESS MANUFACTURERS

12.6.1 Description and Estimate of Small Entities Regulated

DOE conducted a focused inquiry of the companies that could be small business manufacturers of products covered by this rulemaking. For the category "Heating Equipment (except Warm Air Furnaces) Manufacturing," the SBA has set a size threshold of 500 employees or fewer for an entity to qualify as a small business. To identify the number of companies that could be small business manufacturers of products covered by this rulemaking, DOE conducted a market survey using available public information. DOE's research included industry trade association membership directories (*e.g.,* AHRI), public databases (*e.g.*, CEC Appliance Efficiency Database), individual company websites, and market research tools (*e.g.*, Hoover's reports) to create a comprehensive list of companies that manufacture or sell products covered by this rulemaking. DOE also asked interested parties and industry representatives if they were aware of any small manufacturers during manufacturer interviews and at DOE public meetings. DOE reviewed publicly available data and contacted select companies on its list, as necessary, to determine whether they met the SBA's definition of a small business manufacturer of covered products. DOE screened out companies that do not offer products covered by this rulemaking, do not meet the definition of a small business, or are foreign owned and operated.

DOE initially identified 36 potential manufacturers of residential boilers sold in the U.S. DOE then determined that 23 are large manufacturers, manufacturers that are foreign owned and operated, or manufacturers that do not produce products covered by this rulemaking. Thus, DOE was able to determine that 13 domestic manufacturers meet the SBA's definition of a "small

business." Of these 13 small businesses, nine manufacture boilers covered by this rulemaking, while the other four manufacturers rebrand imported products or products manufactured by other small companies.

DOE attempted to contact all small business manufacturers it identified to invite them to take part in a small business manufacturer impact analysis interview. Two of the small businesses agreed to participate in the MIA interview process. DOE also obtained information about small business impacts while interviewing large manufacturers.

DOE estimates that small businesses control approximately 15 percent of the residential boiler market. Based on DOE's research, three small businesses manufacture all four product classes domestically; four small businesses produce primarily high-efficiency condensing products (most of which source condensing heat exchangers from Europe or Asia), and two manufacturers produce primarily oil-fired hot water products. The remaining four wholesale or rebrand products that are imported from Europe or Asia, or design products and source manufacturing to a domestic firm.

12.6.2 Comparison Between Small and Large Entities

The proposed standards for residential boilers could cause small manufacturers to be at a disadvantage relative to large manufacturers. For example, small manufacturers may be disproportionately affected by product conversion costs. Product redesign, testing, and certification costs tend to be fixed and do not scale with sales volume. Small businesses must make investments in research and development to redesign their products, but because they have lower sales volumes, they must spread these costs across fewer units. Moreover, smaller manufacturers may experience higher testing costs relative to larger manufacturers, as they may not possess their own test facilities and therefore must outsource all testing at a higher per unit cost. In general, the three small manufacturers that offer all four product classes have product lines that are similar to those of larger competitors. However, because these small manufacturers have fewer engineers and product development resources, they may have greater difficulty bringing their portfolio of products into compliance with amended energy conservation standards within the allotted timeframe. They also may have to divert engineering resources from consumer and new product initiatives for a longer period of time. These considerations would also apply to the two manufacturers that produce primarily oil-fired hot water products and small businesses that outsource manufacturing but do their own design work.

Smaller manufacturers also may lack the purchasing power of larger manufacturers. For example, suppliers of bulk purchase parts and components, such as gas valves, give boiler manufacturers discounts based on the quantities purchased. Therefore, larger manufacturers may have a pricing advantage because they have higher volume purchases. This purchasing power differential between high-volume and low-volume orders applies to other residential boiler components as well, such as ignition systems and inducer fan assemblies.

In order to meet the proposed standard, manufacturers may have to seek outside capital to cover expenses related to testing and product design equipment. Smaller firms typically have a higher cost of borrowing due to higher perceived risk on the part of investors, largely attributed

to lower cash flows and lower per unit profitability. In these cases, small manufacturers may observe higher costs of debt than larger manufacturers.

While DOE does not expect high capital conversion costs at TSL 3, DOE does expect smaller businesses would have to make significant product conversion investments relative to larger manufacturers. As previously noted, some of these smaller manufacturers' product lines are heavily weighted toward baseline products and other products below the efficiency levels proposed in this Final Rule. As Table 12.6.1 illustrates, smaller manufacturers would have to drastically increase their R&D spending to bring products into compliance and develop new products at TSL 3, the efficiency level proposed in this Final Rule.

Table 12.6.1 and Table 12.6.2 show DOE's estimates of conversion cost impacts on small and large manufacturers.

Table 12.6.1 Impacts of Conversion Costs on a Small Manufacturer

	Capital Conversion Cost as a Percentage of Annual Capital Expenditures %	Product Conversion Cost as a Percentage of Annual R&D Expense %	Total Conversion Cost as a Percentage of Annual Revenue %	Total Conversion Cost as a Percentage of Annual EBIT* %
TSL 1	0	0	0	0
TSL 2	12	76	1	20
TSL 3	17	79	2	22
TSL 4	1,730	1,167	57	759
TSL 5	1,969	1,770	72	958

* Earnings before interest and taxes

Table 12.6.2 Impacts of Conversion Costs on a Large Manufacturer

	Capital Conversion Cost as a Percentage of Annual Capital Expenditures %	Product Conversion Cost as a Percentage of Annual R&D Expense %	Total Conversion Cost as a Percentage of Annual Revenue %	Total Conversion Cost as a Percentage of Annual EBIT* %
TSL 1	0	0	0	0
TSL 2	2	10	0	3
TSL 3	3	10	0	3
TSL 4	345	152	10	134
TSL 5	392	230	12	165

* Earnings before interest and taxes

At TSL 3, the level proposed in this Final Rule, DOE estimates capital conversion costs of $0.01 million and product conversion costs of $0.05 million for an average small manufacturer. This compares to capital conversion costs of $0.02 million and product conversion costs of $0.05 million for an average large manufacturer. These conversion costs would be a relatively higher burden for smaller manufacturers compared to larger manufacturers.

12.7 OTHER IMPACTS

12.7.1 Direct Employment

Employment impacts from new or amended energy conservation standards include direct and indirect impacts. Direct employment impacts are any changes in the number of employees of manufacturers of the equipment subject to standards. Indirect employment impacts are changes in national employment that occur due to the shift in expenditures and capital investment caused by consumers purchasing and operating more efficient equipment.

To quantitatively assess the impacts of energy conservation standards on direct employment in the residential boiler industry, DOE used the GRIM to estimate the domestic labor expenditures and number of employees in the no-new-standards case and at each TSL in 2020. DOE used statistical data from the U.S. Census Bureau's 2011 *Annual Survey of Manufacturers* (*ASM*) ,[b] the results of the engineering analysis, and interviews with manufacturers to determine the inputs necessary to calculate industrywide labor expenditures and domestic employment levels. Labor expenditures related to manufacturing of the product are a function of the labor intensity of the product, the sales volume, and an assumption that wages remain fixed in real terms over time. The total labor expenditures in each year are calculated by multiplying the MPCs by the labor percentage of MPCs.

The total labor expenditures in the GRIM are converted to domestic production employment levels by dividing production labor expenditures by the annual payment per production worker (production worker hours times the labor rate found in the *ASM*). The estimates of production workers in this section cover workers, including line supervisors who are directly involved in fabricating and assembling a product within the manufacturing facility. Workers performing services that are closely associated with production operations, such as materials handling tasks using forklifts, are also included as production labor. DOE's estimates only account for production workers who manufacture the specific products covered by this rulemaking. The total direct employment impacts calculated in the GRIM are the sum of the changes in the number of production workers resulting from the amended energy conservation standards for residential boilers, compared to the no-new-standards case. In general, more efficient boilers are more complex and more labor intensive, requiring specialized knowledge about control systems, electronics, and the different metals needed for the heat exchanger. Per-unit labor requirements and production time requirements increase with higher energy conservation standards. As a result, the total labor calculations described in this paragraph (which are generated by the GRIM) are considered an upper bound to direct employment forecasts.

On the other hand, some manufacturers may choose not to make the necessary investments to meet the amended standards for all product classes. Alternatively, they may choose to relocate production facilities where conversion costs and production costs are lower. To establish a lower bound to negative employment impacts, DOE estimated the maximum potential job loss due to manufacturers either leaving the industry or moving production to

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[b] U.S.Census Bureau, *Annual Survey of Manufacturers: General Statistics: Statistics for Industry Groups and Industries*. <http://factfinder2.census.gov/faces/nav/jsf/pages/searchresults.xhtml?refresh=t>

foreign locations because of amended standards. Most residential boilers manufacturers agreed that higher standards would probably not push their production overseas due to shipping considerations. Rather, high enough standards could force manufacturers to rethink their business models. Instead of vertically integrated manufacturers, they would become assemblers and would likely source most of their components from overseas. This would mean workers involved in casting metals that corrode in a condensing product would likely lose their jobs. These lower bound estimates were based on GRIM results, conversion cost estimates, and content from manufacturers interviews. The lower bound of employment is presented in Table 12.7.1.

DOE estimates that in the absence of amended energy conservation standards, there would be 761 domestic production workers in the residential boiler industry in 2021, the year of compliance. DOE estimates that 90 percent of residential boilers sold in the United States are manufactured domestically. Table 12.7.1 shows the range of the impacts of potential amended energy conservation standards on U.S. production workers of residential boilers.

Table 12.7.1 Potential Changes in the Total Number of Residential Boiler Production Workers in 2021

	Trial Standard Level*					
	No-New-Standards Case	1	2	3	4	5
Total Number of Domestic Production Workers in 2021 (without changes in production locations)	761	761 to 770	753 to 773	745 to 775	381 to 898	190 to 958
Potential Changes in Domestic Production Workers in 2021*	-	0 to 9	(8) to 12	(16) to 14	(380) to 137	(571) to 197

* DOE presents a range of potential employment impacts. Numbers in parentheses indicate negative values.

At the upper end of the range, all examined TSLs show positive impacts on domestic employment levels. Producing more efficient boilers tends to require more labor, and DOE estimates that if residential boiler manufacturers choose to keep their current production in the United States, domestic employment could increase at each TSL. In interviews, several manufacturers who produce high efficiency boiler products stated that a standard that went to condensing levels could cause them to hire more employees to increase their production capacity. Others stated that a condensing standard would require additional engineers to redesign production processes, as well as metallurgy experts and other workers with experience working with higher efficiency products. DOE, however, acknowledges that, particularly at higher standard levels, manufacturers may not keep their production in the United States or may choose to restructure their businesses or exit the market entirely.

DOE does not expect any significant changes in domestic employment at TSL 1 or TSL 2. Most manufactures agreed that these efficiency levels would require minimal changes to their production processes and they would retain most employees. DOE estimates that there could be a small loss of domestic employment at TSL 3 because some manufacturers would have to drop

their 82 to 83-percent-efficient products, which are their commodity products and drive a high percentage of their sales, according to several manufacturers. They also reported that they could lose a significant number of employees at TSL 4 and TSL 5, because these TSLs contain condensing efficiency levels for the gas-fired hot water boiler product class. These manufacturers have employees who work on production lines that produce cast iron sections and carbon steel or copper heat exchangers for low- to mid-efficiency products. If amended energy conservation standards were to require condensing efficiency levels, these employees would no longer be needed for that function, and manufacturers would have to decide whether to develop their own condensing heat exchanger production, source heat exchangers from Asia or Europe and assemble higher efficiency products, or leave the market entirely.

DOE notes that its estimates of the impacts on direct employment are based on the analysis of amended AFUE energy efficiency standards only. Standby mode and off mode technology options considered in the engineering analysis would not make the product significantly more complex or but would result in component swaps. While some product development effort would be required, DOE does not expect the standby mode and off mode standard to significantly affect the amount of labor required in production. Consequently, DOE does not anticipate that the proposed standby mode and off mode standards will have a significant impact on direct employment.

DOE notes that the employment impacts discussed here are independent of the indirect employment impacts to the broader U.S. economy, which are documented in chapter 15 of the Final Rule TSD.

12.7.2 Production Capacity

Most manufacturers stated that their current production is running only at 50 to 70 percent capacity. Further, they stated that only standards in which manufacturers would require condensing technology for hot water boilers would have a large effect on capacity. However, the specific impacts of a potential condensing standard on manufacturer capacity are difficult to quantify. Some manufacturers who are already making condensing products with a sourced heat exchanger said they would likely be able to increase production using the equipment they already have by activating a second shift. Others said a condensing standard would idle a large portion of their business, causing stranded assets and decreased capacity. These manufactures would have to determine how best to increase their condensing boiler production capacity. DOE believes that some larger domestic manufacturers may choose to add production capacity for a condensing heat exchanger production line.

Manufacturers stated that in a scenario where a standard would require condensing technology, there is concern about the level of technical resources required to redesign and test all products. The engineering analysis shows that increasingly complex components and control strategies are required as standard levels increase. Manufacturers commented in interviews that the industry would need to add electrical engineering and control systems engineering talent beyond current staffing to meet the redesign requirements of higher TSLs. Additional training might be needed for manufacturing engineers, laboratory technicians, and service personnel if condensing products were broadly adopted. However, because TSL 3 (the adopted level) would

not require condensing standards, DOE does not expect manufacturers to face long-term capacity constraints due to the standard levels proposed in this Final Rule.

12.7.3 Cumulative Regulatory Burden

While any one regulation may not impose a significant burden on manufacturers, the combined effects of existing and impending regulations may have serious consequences for some manufacturers, subgroups of manufacturers, or an entire industry. Assessing the impact of a single regulation may overlook this cumulative regulatory burden. In addition to energy conservation standards, other regulations can significantly affect manufacturers' financial operations. Multiple regulations affecting the same manufacturer can strain profits and lead companies to abandon product lines or markets with lower expected future returns than competing products. For these reasons, DOE conducts an analysis of cumulative regulatory burden as part of its rulemakings pertaining to appliance efficiency.

12.7.3.1 DOE Regulations for Other Products Produced by Manufacturers in the Residential Boiler Industry

For the cumulative regulatory burden analysis, DOE looks at other regulations that could affect residential boiler manufacturers that will take effect approximately three years before or after the 2021 compliance date of amended energy conservation standards for these products. In interviews, manufacturers cited federal regulation of equipment other than residential boilers that contribute to their cumulative regulatory burden. Table 12.7.2 presents the compliance years and expected industry conversion costs of relevant amended energy conservation standards. DOE has included for reference certain federal regulations that have compliance dates beyond the three-year range of DOE's analysis because they were cited multiple times by manufacturers in interviews and written comments.

Table 12.7.2 Compliance Dates and Expected Conversion Expenses of Federal Energy Conservation Standards Affecting the Residential Boiler Industry

Federal Energy Conservation Standard	Approximate Compliance Date	Estimated Total Industry Conversion Expense
2007 Residential Furnaces & Boilers 72 FR 65136 (Nov. 19, 2007)	2015	$88M (2006$)*
2011 Residential Furnaces 76 FR 37408 (June 27, 2011); 76 FR 67037 (Oct. 31, 2011)	2015	$2.5M (2009$)**
Commercial Refrigeration Equipment 79 FR 17725 (March 28, 2014)	2017	$184.0M (2012$)
Commercial Packaged Air Conditioners and Heat Pumps***	2018	TBD
Commercial Warm-Air Furnaces 80 FR 6182 (Feb 4, 2015)	2018	$19.9 Million (2013$)

Furnace Fans 79 FR 38130 (July 3, 2014)	2019	$40.6M (2014$)
Single Package Vertical Air Conditioners and Heat Pumps 80 FR 57438 (Sept 23, 2015)	2019	$9.2M (2014$)
Commercial Water Heaters***	2019	TBD
Packaged Terminal Air Conditioners and Heat Pumps 80 FR 43162 (July 21, 2015)	2019	N/A
Commercial Packaged Boilers***	2021	TBD
Non-weatherized Gas-fired Furnaces and Mobile Home Furnaces***	2021	TBD
Direct Heating Equipment/Pool Heaters***	2021	TBD
Residential Water Heaters***	2021	TBD
Central Air Conditioners***	2022	TBD
Room Air Conditioners***	2022	TBD
Commercial Packaged Air Conditioning and Heating Equipment (Evaporative and Water Cooled) ***	2023	TBD

* Conversion expenses for manufacturers of oil-fired furnaces and gas- and oil-fired boilers associated with the November 2007 final rule for residential furnaces and boilers are excluded from this figure. The 2011 direct final rule for residential furnaces sets a higher standard and earlier compliance date for oil furnaces than the 2007 final rule. As a result, manufacturers will be required to design to the 2011 direct final rule standard. The conversion costs associated with the 2011 direct final rule are listed separately in this table. EISA 2007 legislated higher standards and earlier compliance dates for residential boilers than were in the November 2007 final rule. As a result, gas-fired and oil-fired boiler manufacturers were required to design to the EISA 2007 standard beginning in 2012. The conversion costs listed for residential gas-fired and oil-fired boilers in the November 2007 residential furnaces and boilers final rule analysis are not included in this figure.
**Estimated industry conversion expense and approximate compliance date reflect a court-ordered May 1, 2013, stay of the residential non-weatherized and mobile home gas furnaces standards set in the 2011 Energy Conservation Standards for Residential Furnaces and Residential Central Air Conditioners and Heat Pumps.
***The NOPR and final rule for this energy conservation standard have not been published. The compliance date and analysis of conversion costs are estimates and have not been finalized at this time.

During previous stages of this rulemaking, DOE identified other relevant requirements in addition to amended energy conservation standards residential boilers. The following section briefly summarizes these regulatory requirements and addresses comments DOE received with respect to the cumulative regulatory burden, as well as other key related concerns manufacturers raised during interviews.

12.7.3.2 Other DOE and Federal Actions Affecting Manufacturers in the Residential Boiler Industry

Modified DOE Test Procedure. DOE is considering revising the test procedure for residential furnaces and boilers, and expects a revised test procedure would increase testing burden for manufacturers. On August 30, 2008, DOE published a technical amendment to the 2007 furnaces and boilers final rule. The purpose of this amendment was to add design requirements established in EISA 2007. 73 FR 43611. These requirements prohibit constant-burning pilot lights for gas-fired hot water boilers and gas-fired steam boilers, and require an automatic means for adjusting the water temperature for gas-fired hot water boilers, oil-fired hot water boilers, and electric hot water boilers. The test procedure will be revised to include two test methods to verify the functionality of the automatic means of adjusting the water temperature. The inclusion of these two test methods is expected to increase the testing burden for residential boiler manufacturers and thereby the cumulative regulatory burden.

12.8 CONCLUSION

This section summarizes the impacts for the scenarios most likely to capture the range of impacts on residential boiler manufacturers as a result of amended energy conservation standards. DOE also notes that while these scenarios bound the range of most plausible impacts on manufacturers, circumstances could potentially cause manufacturers to experience impacts outside of this range.

12.8.1 Impacts for Residential Boilers in Active Mode

Table 12.8.1 and Table 12.8.2 summarize INPV impacts and conversion costs projected to result from each of the trial standard levels analyzed.

Table 12.8.1 Expected INPV and Conversion Cost Impacts for Residential Boilers – Preservation of Gross Margin Percentage Scenario (Active Mode)

			Trial Standard Level				
	Units	**No-New-Standards Case**	**1**	**2**	**3**	**4**	**5**
INPV	2014$ millions	367.83	367.50	368.69	369.45	349.47	366.71
Change in INPV	2014$ millions	-	(0.33)	0.86	1.62	(18.35)	(1.12)
Change in INPV	%	-	(0.09)	0.24	0.44	(4.99)	(0.30)
Product Conversion Costs	2014$ millions	-	1.34	1.60	1.66	24.53	37.19
Capital Conversion Costs	2014$ millions	-	-	0.43	0.61	61.10	69.52
Total Investment Required	2014$ millions	-	1.34	2.03	2.27	85.63	106.71
Free Cash Flow (2019)	2014$ millions	26.42	26.01	25.74	25.64	(8.43)	(16.02)
Change in Free Cash Flow	2014$ millions	-	(0.4)	(0.7)	(0.8)	(34.9)	(42.4)
	%	-	(1.52)	(2.55)	(2.92)	(131.93)	(160.65)

Note: Numbers in parentheses indicate negative numbers.

Table 12.8.2 Expected INPV and Conversion Cost Impacts for Residential Boilers – Preservation of Per Unit Operating Profit Scenario (Active Mode)

	Units	**No-New-Standards Case**	Trial Standard Level				
			1	**2**	**3**	**4**	**5**
INPV	2014$ millions	367.83	365.70	364.94	365.20	284.21	225.88
Change in INPV	2014$ millions	-	(2.12)	(2.89)	(2.63)	(83.61)	(141.95)
Change in INPV	%	-	(0.58)	(0.79)	(0.71)	(22.73)	(38.59)
Product Conversion Costs	2014$ millions	-	1.34	1.60	1.66	24.53	37.19
Capital Conversion Costs	2014$ millions	-	-	0.43	0.61	61.10	69.52
Total Investment Required	2014$ millions	-	1.34	2.03	2.27	85.63	106.71
Free Cash Flow (2019)	2014$ millions	26.42	26.01	25.74	25.64	(8.43)	(16.02)
Change in Free Cash Flow	2014$ millions	-	(0.4)	(0.7)	(0.8)	(34.9)	(42.4)
	%	-	(1.52)	(2.55)	(2.92)	(131.93)	(160.65)

Note: Numbers in parentheses indicate negative numbers.

TSL 1 represents EL 1 for all product classes. At TSL 1, DOE estimates impacts on INPV for residential boiler manufacturers to range from -0.58 percent to -0.09 percent, or a change in INPV of -$2.12 million to -$0.33 million. At this potential standard level, industry free cash flow would be estimated to decrease by approximately 1.52 percent to $26.01 million, compared to the no-new-standards case value of $26.42 million in 2020, the year before the compliance date.

At TSL 1, DOE does not anticipate manufacturers would lose a significant portion of their INPV. This is largely due to the fact that the vast majority of shipments would already meet or exceed the efficiency levels prescribed at TSL 1. DOE projects that in 2020, the expected year of compliance, approximately 85 percent of residential boiler shipments would meet or exceed the efficiency levels at TSL 1. As a result, only a small percentage of residential boiler shipments would need to be converted to TSL 1, so DOE expects low conversion costs at this TSL. DOE expects residential boiler manufacturers to incur $1.34 million in product conversion costs for boiler redesign and testing. DOE does not expect the modest efficiency gains at this TSL to require any major equipment upgrades or capital investments.

At TSL 1, under the preservation of gross margin percentage scenario, the shipment-weighted average MPC increases by approximately 1 percent relative to the no-new-standards case MPC. Manufacturers are able to fully pass on this cost increase to consumers by design in this markup scenario. This slight price increase would not mitigate the $1.34 million in conversion costs estimated at TSL 1, resulting in slightly negative INPV impacts at TSL 1 under the this scenario.

Under the preservation of per-unit operating profit markup scenario, manufacturers earn the same operating profit as would be earned in the no-new-standards case, but do not earn additional profit from their investments. The 1-percent MPC increase is outweighed by a slightly lower average markup and $1.34 million in conversion costs, resulting in small negative impacts at TSL 1.

TSL 2 sets the efficiency level at EL 1 for three product classes (gas-fired steam boilers, gas-fired hot water boilers, and oil-fired steam boilers) and EL 2 for one product classes (oil-fired hot water boilers). At TSL 2, DOE estimates impacts on INPV for residential boiler manufacturers to range from -0.79 percent to 0.24 percent, or a change in INPV of -$2.89 million to $0.86 million. At this potential standard level, industry free cash flow would be estimated to decrease by approximately 2.55 percent to $25.74 million, compared to the no-new-standards case value of $26.42 million in 2020, the year before the compliance date.

DOE does not anticipate manufacturers would lose a substantial portion of their INPV, because a large percentage of shipments would still meet or exceed the energy conservation levels prescribed at this TSL. At TSL 2, DOE estimates that in 2020, 74 percent of residential boiler shipments would meet or exceed the energy conservation levels analyzed. The drop in the percentage of compliant products is largely due to the fact that the oil-fired hot water product class would move to EL 2 and the oil-fired steam product class would move to EL 2. At these efficiency levels, DOE projects only 41 percent and 10 percent of shipments of hot water and steam oil-fired boilers, respectively, would meet or exceed the levels at TSL 2 in 2020, the year of compliance. These figures do not have a large impact on INPV, however, because oil-fired

boilers would only comprise approximately 30 percent of residential boiler shipments in 2020, according to DOE projections, while gas-fired boilers would comprise more than 70 percent of shipments.

DOE expects conversion costs to increase, but they would still remain small compared to total industry value, as most manufacturers have gas-fired boilers at the prescribed efficiency levels on the market and would have to make only minor changes to their production processes. While the percentage of oil-fired boilers at these efficiency levels on the market is lower, manufacturers did not cite any major investments that would have to be made to reach the efficiency levels at EL 2 for hot water products and EL 3 for steam products. Manufacturers also pointed out that gas-fired boiler shipments vastly out-pace oil-fired boiler shipments and that the market is continuing to trend towards gas-fired products. Overall, DOE estimates manufacturers would incur $1.60 million in product conversion costs for product redesign and testing and $0.43 million in capital conversion costs to make minor changes to their production lines.

At TSL 2, under the preservation of gross margin percentage scenario, the shipment-weighted average MPC increases by two percent relative to the no-new-standards case MPC. In this scenario, INPV impacts are slightly positive because of manufacturers' ability to pass the higher production costs to consumers outweighs the $2.03 million in conversion costs. Under the preservation of per-unit operating profit markup scenario, the 2-percent MPC increase is outweighed by a slightly lower average markup and $2.03 million in conversion costs, resulting in minimally negative impacts at TSL 2.

TSL 3 represents EL 1 for one product class (gas-fired steam boilers) and EL 2 for three product classes (oil-fired hot water boilers, gas-fired hot water boilers, and oil-fired steam boilers). At TSL 3, DOE estimates impacts on INPV for residential boiler manufacturers to range from -0.71 percent to 0.44 percent, or a change in INPV of -$2.63 million to $1.62 million. At this potential standard level, industry free cash flow would be estimated to decrease by approximately 2.92 percent in 2020, the year before compliance, to $25.64 million compared to the no-new-standards case value of $26.42 million.

While more significant than the impacts at TSL 2, the impacts on INPV at TSL 3 would still be relatively minor compared to the total industry value. Percentage impacts on INPV would be slightly positive to slightly negative at TSL 3. DOE does not anticipate that manufacturers would lose a significant portion of their INPV at this TSL. While less than the previous TSLs, DOE projects that in 2020, 63 percent of product listings already meet or exceed the energy conservation levels prescribed at TSL 3. DOE expects conversion costs to remain small at TSL 3 compared to the total industry value. DOE estimates that product conversion costs would increase as manufacturers would have to redesign a larger percentage of their offerings and may have to design new products to replace lower efficiency commodity products. At this TSL, DOE estimates that residential boiler manufacturers would incur $3.38 million in product conversion costs. Manufacturers, however, did not cite any major changes that would need to be made to production equipment to achieve the energy conservation levels at this TSL. DOE, therefore, estimates that capital conversion costs would remain at $0.90 million for the industry.

At TSL 3, under the preservation of gross margin percentage markup scenario, the shipment-weighted average MPC increases by four percent relative to the no-new-standards case

MPC. In this scenario, INPV impacts are slightly positive because manufacturers' ability to pass the higher production costs to consumers outweighs the $2.27 million in conversion costs. Under the preservation of per-unit operating profit markup scenario, the four percent MPC increase is slightly outweighed by a slightly lower average markup and $2.27 million in conversion costs, resulting in minimally negative impacts at TSL 3.

TSL 4 represents EL 1 for one product class (gas-fired steam boilers), EL 3 for two product classes (oil-fired hot water boilers and oil-fired steam boilers), and EL 5 for one product class (gas-fired hot water boilers). At TSL 4, DOE estimates impacts on INPV for residential boiler manufacturers to range from -22.73 percent to -4.99 percent, or a change in INPV of -$83.61 million to -$18.35 million. At this potential standard level, industry free cash flow would be estimated to decrease by approximately 131.93 percent in the year before compliance (2020) to -$8.43 million relative to the no-new-standards case value of $26.42 million.

Percentage impacts on INPV are moderately to significantly negative at TSL 4. DOE projects that in 2020, only 27 percent of residential boiler shipments would meet or exceed the efficiency levels at TSL 4. DOE expects that conversion costs would increase significantly at this TSL due to the fact that manufacturers would meet these efficiency levels by using condensing heat exchangers in their gas-fired and oil-fired hot water boiler products.[c] Currently, the majority of gas-fired hot water boilers on the market is made from cast iron, carbon steel, or copper and contains noncondensing heat exchangers, because if these boilers were designed to condense, the acidic condensate from the flue gas would corrode these metals and cause the boiler to fail prematurely. If standards were set where manufacturers of gas-fired hot water boiler products could only meet the efficiency levels with condensing technology, companies that produce their own cast iron sections or their own carbon steel or copper heat exchangers would have to eliminate many of their commodity products, close foundries and casting facilities, and restructure their businesses. Domestic manufacturers who currently offer condensing products import their condensing heat exchangers (constructed from either stainless steel or aluminum) from Europe. DOE believes that if standards were set where manufacturers of gas-fired hot water boiler products could only meet the energy conservation levels with condensing technology, some manufacturers may choose to develop their own condensing heat exchanger production capacity in order to gain a cost advantage and remain vertically integrated. This would require large capital investments in higher tech, more automated production lines, and new equipment to handle the different metals that are required. Companies that are currently heavily invested in lower efficiency products may not be able to make these investments and may choose to exit the market. As noted above, these companies also may choose to source condensing heat exchangers and assemble a product designed around the sourced part, rather than invest in their own heat exchanger production capacity. This strategy would remove a significant piece of the value chain for these companies.

While condensing products and condensing technology are not entirely unfamiliar to the companies that already make condensing products domestically, most manufacturers in the residential boiler industry have relatively little experience in manufacturing the heat exchanger

[c] At these efficiency levels, manufacturers would also use a condensing heat exchanger for oil-fired hot water boiler products; however, these models are much less common, and DOE believes that the majority of the conversion costs at this TSL would be driven by gas-fired hot water boiler products.

itself. If manufacturers choose to develop their own heat exchanger production capacity, a great deal of testing, prototyping, design, and manufacturing engineering resources will be required to design the heat exchanger and the more advanced control systems found in more efficient products.

These capital and production conversion expenses lead to the large reduction in cash flow in the years preceding the standard. DOE believes that only a few domestic manufacturers have the resources for this undertaking and believes that some large manufacturers and many smaller manufacturers would continue to source their heat exchangers. DOE estimates that manufacturers ultimately would incur $25.04 million in product conversion costs, as some manufacturers would be expected to attempt to add production capacity for condensing heat exchangers and others would have to design baseline products around a sourced condensing heat exchanger. In addition, DOE estimates that manufacturers would incur $60.13 million in capital conversion costs, which would be driven by capital investments in heat exchanger production lines.

At TSL 4, under the preservation of gross margin percentage markup scenario, the shipment-weighted average MPC increases by 37 percent relative to the no-new-standards case MPC. In this scenario, INPV impacts are slightly negative because manufacturers' ability to pass the higher production costs to consumers is slightly outweighed the $85.16 million in conversion costs. Under the preservation of per-unit operating profit markup scenario, the 30-percent MPC increase is outweighed by a lower average markup of 1.39 (compared to 1.41 in the preservation of gross margin percentage markup scenario) and $85.63 million in conversion costs, resulting in significantly negative impacts at TSL 4.

TSL 5 represents EL 2 for one product class (gas-fired steam boilers), EL 3 for two product classes (oil-fired hot water boilers and oil-fired steam boilers), and EL 6 for one product class (gas-fired hot water boilers). TSL 5 represents max tech for all product classes. At TSL 5, DOE estimates impacts on INPV for residential boiler manufacturers to range from -38.59 percent to -0.30 percent, or a change in INPV of -$141.95 million to -$1.12 million. At this potential standard level, industry free cash flow would be estimated to decrease by approximately 160.65 percent in the year before compliance (2020) to -$16.02 million relative to the no-new-standards case value of $26.42 million.

At TSL 5, percentage impacts on INPV range from slightly to significantly negative. DOE estimates that only 4 percent of residential boiler shipments already meet or exceed the energy conservation levels prescribed at TSL 5 today. DOE expects conversion costs to continue to increase at TSL 5, as almost all products on the market would have to be redesigned and new products would have to be developed. At these energy conservation levels as with TSL 4, some manufacturers would choose to develop their own condensing heat exchanger production, rather than continuing to source these components. DOE estimates that product conversion costs would increase to $37.19 million as manufacturers would have to redesign a larger percentage of their offerings, implement complex control systems, and meet max tech for all product classes. DOE estimates that manufacturers would incur $69.52 million in capital conversion costs due to some manufacturers choosing to develop their own heat exchanger production and others having to increase the throughput of their existing condensing boiler production lines.

At TSL 5, under the preservation of gross margin percentage markup scenario, the shipment-weighted average MPC increases by 61 percent relative to the no-new-standards case MPC. In this scenario, INPV impacts are negative because manufacturers' ability to pass the higher production costs to consumers is outweighed by the $106.71 million in conversion costs. Under the preservation of per-unit operating profit markup scenario, the 61-percent MPC increase is outweighed by a lower average markup of 1.36 and $106.71 million in conversion costs, resulting in significantly negative impacts at TSL 5.

12.8.2 Impacts for Residential Boilers in Standby/Off Mode

Table 12.8.3 and Table 12.8.4 summarize INPV impacts and conversion costs projected to result from each of the trial standard levels analyzed. Note that the TSLs listed in the following tables represent different sets of efficiency levels than the TSLs discussed previously in the description of impacts on residential boilers in active mode.

Table 12.8.3 Expected INPV and Conversion Cost Impacts for Residential Boilers – Preservation of Gross Margin Percentage Scenario (Standby/Off Mode)

	Units	No-New-Standards Case	Trial Standard Level		
			1	2	3
INPV	2014$ millions	367.83	367.73	367.74	368.28
Change in INPV	2014$ millions	-	(0.10)	(0.09)	0.45
Change in INPV (%)	%	-	(0.03)	(0.02)	0.12
Product Conversion Costs	2014$ millions	-	0.21	0.21	0.21
Capital Conversion Costs	2014$ millions	-	-	-	-
Total Investment Required	2014$ millions	-	0.21	0.21	0.21
Free Cash Flow (2019)	2014$ millions	26.42	26.35	26.35	26.35
Change in Free Cash Flow	2014$ millions	-	(0.06)	(0.06)	(0.06)
	%	-	(0.24)	(0.24)	(0.24)

Table 12.8.4 Expected INPV and Conversion Cost Impacts for Residential Boilers – Preservation of Per Unit Operating Profit Scenario (Standby/Off Mode)

	Units	No-New-Standards Case	Trial Standard Level		
			1	2	3
INPV	2014$ millions	367.83	367.61	367.78	366.12
Change in INPV	2014$ millions	-	(0.22)	(0.04)	(1.71)
Change in INPV	%	-	(0.06)	(0.01)	(0.46)

Product Conversion Costs	2014$ millions	-	0.21	0.21	0.21
Capital Conversion Costs	2014$ millions	-	-	-	-
Total Investment Required	2014$ millions	-	0.21	0.21	0.21
Free Cash Flow (2019)	2014$ millions	26.42	26.35	26.35	26.35
Change in Free Cash Flow	2014$ millions	-	(0.06)	(0.06)	(0.06)
	%	-	(0.24)	(0.24)	(0.24)

TSL 1 represents EL 1 for all product classes. At TSL 1, DOE estimates impacts on INPV for residential boiler manufacturers to decrease by less than one tenth of a percent in both markup scenarios, which corresponds to a change in INPV of -$0.22 million to -$0.10 million. At this potential standard level, industry free cash flow is estimated to decrease by approximately 0.24 percent to $26.35 million, compared to the no-new-standards case value of $26.42 million in 2020, the year before the compliance date.

At TSL 1, DOE does not anticipate that manufacturers would lose a significant portion of their INPV. This is largely due to the small incremental costs of standby mode and off mode components relative to the overall cost of residential boiler production. DOE expects residential boiler manufacturers to incur $0.21 million in product conversion costs at TSL 1, primarily for testing. DOE does not expect that manufacturers would incur any capital conversion costs, as the product upgrades will only involve integrating a purchase-part.

TSL 2 sets the efficiency level at EL 2 for all product classes. At TSL 2, DOE estimates impacts on INPV for residential boilers manufacturers to range from -0.02 percent to -0.01 percent, or a change in INPV of -$0.09 million to -$0.04 million. At this potential standard level, industry free cash flow is estimated to decrease by approximately 0.24 percent to $26.35 million, compared to the no-new-standards case value of $26.42 million in 2020, the year before the compliance date.

At TSL 2, DOE does not anticipate that manufacturers would lose a significant portion of their INPV. This is largely due to the small incremental costs of standby mode and off mode components relative to the overall cost of residential boiler production. DOE expects residential boiler manufacturers to incur $0.21 million in product conversion costs at TSL 2, primarily for testing. DOE does not expect that manufacturers would incur any capital conversion costs, as the product upgrades will only involve integrating a purchase-part.

TSL 3 represents EL 3 for all product classes. At TSL 3, DOE estimates impacts on INPV for residential boiler manufacturers to range from -0.46 percent to 0.12 percent, or a change in INPV of -$1.71 million to $0.45 million. At this potential standard level, industry free cash flow is estimated to decrease by approximately 0.24 percent in the year before compliance to $26.35 million compared to the no-new-standards case value of $26.42 million in 2020, the year before the compliance date.

At TSL 3, DOE does not anticipate that manufacturers would lose a significant portion of their INPV. As with TSLs 1 and 2, this is largely due to the small incremental costs of standby

mode and off mode components relative to the overall cost of residential boiler production. DOE expects residential boiler manufacturers to incur $0.21 million in product conversion costs at TSL 3, primarily for testing. DOE does not expect that manufacturers would incur any capital conversion costs, as the product upgrades will only involve integrating a purchase-part.

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APPENDIX 12A GOVERNMENT REGULATORY IMPACT MODEL (GRIM) OVERVIEW

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12A.1 INTRODUCTION AND PURPOSE

The purpose of the Government Regulatory Impact Model (GRIM) is to help quantify the impacts of energy conservation standards and other regulations on manufacturers. The basic mode of analysis is to estimate the change in the value of the industry or manufacturers following a regulation or a series of regulations. The model structure also allows an analysis of multiple products with regulations taking effect over a period of time, and of multiple regulations on the same products.

Industry net present value is defined, for the purpose of this analysis, as the discounted sum of industry free cash flows plus a discounted terminal value. The model calculates the actual cash flows by year and then determines the present value of those cash flows both without an energy conservation standard (*i.e.*, the base case) and under different trial standard levels (TSLs) (*i.e.*, the standards case).

Output from the model consists of summary financial metrics, graphs of major variables, and, when appropriate, access to the complete cash flow calculation.

12A.2 RESIDENTIAL BOILER DESCRIPTION

DOE analyzed the impacts of standards on residential boiler manufacturers. The basic structure of the GRIM is a standard annual cash flow analysis that uses manufacturer selling prices, manufacturing costs, a shipments forecast, and financial parameters as inputs and accepts a set of regulatory conditions as changes in costs and investments. The cash flow analysis is separated into two major blocks: income and cash flow. The income calculation determines net operating profit after taxes. The cash flow calculation converts net operating profit after taxes into an annual cash flow by including investment and non-cash items. The line items below relate to the residential boiler manufacturers and are definitions of listed items on the printout of the output sheet (see section 12A.3).

(1) Revenues: Annual revenues - computed by multiplying products' unit prices at each efficiency level by the appropriate manufacturer markup;

(2) Total Shipments: The total covered units shipped;

(3) Materials: The portion of cost of goods sold (COGS) that includes materials;

(4) Labor: The portion of COGS that includes direct labor, commissions, dismissal pay, bonuses, vacation, sick leave, social security contributions, fringe, and assembly labor up-time;

(5) Depreciation: The portion of COGS that includes an allowance for the total amount of fixed assets used to produce that one unit;

(6) Overhead: The portion of COGS that includes indirect labor, indirect material, energy use, maintenance, property taxes, and insurance related to assets;

(7) Standard SG&A: Selling, general, and administrative costs are computed as a percentage of ***Revenues (1)***;

(8) R&D: GRIM separately accounts for ordinary research and development (R&D) as a percentage of ***Revenues (1)***;

(9) Product Conversion Costs: Product conversion costs are one-time investments in research, development, testing, marketing, and other costs focused on making product designs comply with amended energy conservation standards. The GRIM allocates these costs over the period between the standards' announcement and compliance dates;

(10) Stranded Assets: In the year the standard becomes effective, a one-time write-off of stranded assets is accounted for

(11) Earnings Before Interest and Taxes (EBIT): Includes profits before deductions for interest paid and taxes;

(12) Per Unit EBIT: The average amount of ***EBIT (11)*** per covered unit shipped;

(13) EBIT/Revenues: EBIT (11) as a percentage of sales to compare with the industry's average reported in financial statements;

(14) Taxes: Taxes on ***EBIT (11)*** are calculated by multiplying the tax rate contained in the Discounted Cash Flow tab by ***EBIT (11)***;

(15) Net Operating Profits After Taxes (NOPAT): Computed by subtracting ***Taxes (14)*** from ***EBIT (11)***;

(16) NOPAT repeated: NOPAT (15) is repeated in the Statement of Cash Flows;

(17) Depreciation repeated: Depreciation (5) is added back in the Statement of Cash Flows because it is a non-cash expense;

(18) Stranded Assets repeated: Stranded Assets (10) is added back in the Statement of Cash Flows because it is a non-cash expense;

(19) Change in Working Capital: Change in cash tied up in accounts receivable, inventory, and other cash investments necessary to support operations is calculated by multiplying working capital (as a percentage of revenues) by the change in annual revenues;

(20) Cash Flow From Operations: Calculated by taking ***NOPAT (16)***, adding back non-cash items such as ***Depreciation (17)*** and ***Stranded Assets (18)***, and subtracting the ***Change in Working Capital (19)***;

(21) Ordinary Capital Expenditures: Ordinary investments in property, plant, and equipment to maintain and replace existing production assets, computed as a percentage of ***Revenues (1)***;

(22) Capital Conversion Costs: Capital conversion costs are one-time investments in property, plant, and equipment to adapt or change existing production facilities so that

new product designs can be fabricated and assembled under amended regulations; the GRIM allocates these costs over the period between the standards' announcement and compliance dates;

(23) Free Cash Flow: Calculated by taking annual ***Cash Flow From Operations (20)*** and subtracting ***Ordinary Capital Expenditures (21)*** and ***Capital Conversion Costs (22)***;

(24) Free Cash Flow repeated: Free Cash Flow (23) is repeated in the Discounted Cash Flow section;

(25) Terminal Value: Estimate of the continuing value of the industry after the analysis period. Computed by growing the ***Free Cash Flow (24)*** at the beginning of 2050 at a constant rate in perpetuity;

(26) Present Value Factor: Factor used to calculate an estimate of the present value of an amount to be received in the future;

(27) Discounted Cash Flow: Free Cash Flow (23) multiplied by the ***Present Value Factor (26)***. For the end of 2050, the discounted cash flow includes the discounted ***Terminal Value (25)***; and

(28) ***Industry Net Present Value****:* The sum of ***Discounted Cash Flows (27)*** through the end of 2050.

12A.3 RESIDENTIAL BOILERS DETAILED CASH FLOW EXAMPLE

Standard Case DCF | **Navigation**

Industry Income Statement (in millions)	2014	2015 (Ancmt Yr)	2016	2017	2018	2019	2020	2021 (Std Yr)	2022	2023	2024	2025	2026
Revenues	$ 497.5	$ 529.8	$ 528.8	$ 541.4	$ 541.4	$ 545.3	$ 551.6	$ 562.7	$ 571.3	$ 576.1	$ 580.8	$ 584.3	$ 583.5
Total Shipments	0.365	0.389	0.385	0.392	0.389	0.389	0.391	0.388	0.394	0.396	0.399	0.401	0.400
- Materials	$ 278.7	$ 296.9	$ 296.7	$ 304.1	$ 304.4	$ 307.0	$ 310.9	$ 317.9	$ 322.8	$ 325.7	$ 328.5	$ 330.6	$ 330.3
- Labor	$ 28.6	$ 30.4	$ 30.2	$ 30.7	$ 30.6	$ 30.7	$ 30.9	$ 31.4	$ 31.8	$ 32.1	$ 32.3	$ 32.4	$ 32.3
- Depreciation	$ 11.1	$ 11.8	$ 11.7	$ 11.9	$ 11.9	$ 11.9	$ 11.9	$ 11.8	$ 12.0	$ 12.1	$ 12.1	$ 12.2	$ 12.1
- Overhead	$ 34.5	$ 36.7	$ 36.5	$ 37.2	$ 37.1	$ 37.2	$ 37.5	$ 38.0	$ 38.5	$ 38.7	$ 39.0	$ 39.1	$ 39.0
- Standard SG&A	$ 99.5	$ 106.0	$ 105.8	$ 108.3	$ 108.3	$ 109.1	$ 110.3	$ 112.5	$ 114.3	$ 115.2	$ 116.2	$ 116.9	$ 116.7
- R&D	$ 8.0	$ 8.5	$ 8.5	$ 8.7	$ 8.7	$ 8.7	$ 8.8	$ 9.0	$ 9.1	$ 9.2	$ 9.3	$ 9.3	$ 9.3
- Product Conversion Costs	$ -	$ -	$ -	$ 0.0	$ 0.3	$ 0.6	$ 0.7	$ 0.0	$ -	$ -	$ -	$ -	$ -
- Stranded Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9.3	$ -	$ -	$ -	$ -	$ -
Earnings Before Interest and Taxes (EBIT)	$ 37.2	$ 39.6	$ 39.5	$ 40.5	$ 40.2	$ 40.2	$ 40.5	$ 32.7	$ 42.7	$ 43.1	$ 43.4	$ 43.7	$ 43.6
Per Unit EBIT ($)	$ 101.88	$ 101.89	$ 102.64	$ 103.26	$ 103.35	$ 103.25	$ 103.71	$ 84.32	$ 108.55	$ 108.69	$ 108.80	$ 108.91	$ 109.01
EBIT/Revenues (%)	*7.5%*	*7.5%*	*7.5%*	*7.5%*	*7.4%*	*7.4%*	*7.3%*	*5.8%*	*7.5%*	*7.5%*	*7.5%*	*7.5%*	*7.5%*
- Taxes	$ 11.9	$ 12.7	$ 12.7	$ 12.9	$ 12.9	$ 12.9	$ 13.0	$ 10.5	$ 13.7	$ 13.8	$ 13.9	$ 14.0	$ 14.0
Net Operating Profit after Taxes (NOPAT	**$ 25.3**	**$ 26.9**	**$ 26.9**	**$ 27.5**	**$ 27.3**	**$ 27.3**	**$ 27.6**	**$ 22.3**	**$ 29.0**	**$ 29.3**	**$ 29.5**	**$ 29.7**	**$ 29.7**
Cash Flow Statement													
NOPAT	$ 25.3	$ 26.9	$ 26.9	$ 27.5	$ 27.3	$ 27.3	$ 27.6	$ 22.3	$ 29.0	$ 29.3	$ 29.5	$ 29.7	$ 29.7
+ Depreciation	$ 11.1	$ 11.8	$ 11.7	$ 11.9	$ 11.9	$ 11.9	$ 11.9	$ 11.8	$ 12.0	$ 12.1	$ 12.1	$ 12.2	$ 12.1
+ Loss on Disposal of Stranded Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 9.3	$ -	$ -	$ -	$ -	$ -
- Change in Working Capital	$ -	$ 7.4	$ (0.2)	$ 2.9	$ (0.0)	$ 0.9	$ 1.4	$ 2.6	$ 2.0	$ 1.1	$ 1.1	$ 0.8	$ (0.2)
Cash Flows from Operations	$ 36.4	$ 31.3	$ 38.8	$ 36.5	$ 39.2	$ 38.3	$ 38.1	$ 40.9	$ 39.1	$ 40.3	$ 40.6	$ 41.1	$ 42.0
- Ordinary Capital Expenditures	$ 10.9	$ 11.7	$ 11.6	$ 11.9	$ 11.9	$ 12.0	$ 12.1	$ 12.4	$ 12.6	$ 12.7	$ 12.8	$ 12.9	$ 12.8
- Capital Conversion Costs	$ -	$ -	$ -	$ 0.0	$ 0.1	$ 0.2	$ 0.3	$ -	$ -	$ -	$ -	$ -	$ -
Free Cash Flow	**$ 25.5**	**$ 19.7**	**$ 27.2**	**$ 24.6**	**$ 27.2**	**$ 26.1**	**$ 25.64**	**$ 28.5**	**$ 26.5**	**$ 27.6**	**$ 27.8**	**$ 28.2**	**$ 29.2**
Discounted Cash Flow													
Free Cash Flow	$ 25.5	$ 19.7	$ 27.2	$ 24.6	$ 27.2	$ 26.1	$ 25.6	$ 28.5	$ 26.5	$ 27.6	$ 27.8	$ 28.2	$ 29.2
Terminal Value	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Present Value Factor	*0.000*	*1.000*	*0.926*	*0.857*	*0.794*	*0.735*	*0.681*	*0.630*	*0.583*	*0.540*	*0.500*	*0.463*	*0.429*
Discounted Cash Flow	**$ -**	**$ 19.7**	**$ 25.2**	**$ 21.1**	**$ 21.6**	**$ 19.2**	**$ 17.5**	**$ 17.9**	**$ 15.5**	**$ 14.9**	**$ 13.9**	**$ 13.1**	**$ 12.5**

INPV at TSL 3 $ 369.45

Net PPE	$ 73.4	$ 73.2	$ 73.2	$ 73.2	$ 73.3	$ 73.7	$ 74.1	$ 65.4	$ 65.9	$ 66.5	$ 67.2	$ 67.8	$ 68.5
Net PPE as % of Sales	14.8%	13.8%	13.8%	13.5%	13.5%	13.5%	13.4%	11.6%	11.5%	11.5%	11.6%	11.6%	11.7%
Net Working Capital	$ 114.4	$ 121.9	$ 121.6	$ 124.5	$ 124.5	$ 125.4	$ 126.9	$ 129.4	$ 131.4	$ 132.5	$ 133.6	$ 134.4	$ 134.2
Return on Invested Capital (ROIC)	13.47%	13.81%	13.81%	13.92%	13.82%	13.73%	13.71%	11.43%	14.72%	14.72%	14.71%	14.69%	14.64%
Weighted Average Cost of Capital (WACC)	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Return on Sales (EBIT/Sales)	7.48%	7.48%	7.48%	7.47%	7.43%	7.37%	7.35%	5.82%	7.48%	7.48%	7.48%	7.48%	7.48%

This tab computes key parameters from an income statement based on unit sales, revenues and COGS, and initial financial inputs (parameters as a % of revenue). It also computes an INPV based on a discounted cash flow model.

APPENDIX 12B. MANUFACTURER IMPACT ANALYSIS INTERVIEW GUIDE

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Appendix 12B. Manufacturer Impact Analysis Interview Guide

12B.1 MANUFACTURER IMPACT ANALYSIS INTERVIEW GUIDE FOR RESIDENTIAL BOILERS

Introduction

As part of this rulemaking process for energy conservation standards for residential boilers, the Department of Energy (DOE) is conducting a manufacturer impact analysis (MIA). In this analysis, DOE uses publicly available information and information provided by manufacturers during interviews to assess possible impacts on manufacturers due to energy conservation standards.

This questionnaire is a part of the MIA process and is intended to inform the Department's understanding of how changes in the energy conservation standard will affect residential boiler manufacturers. All information provided in response to this questionnaire will be treated as confidential. The questions below range from requests about specific financial figures for use in industry modeling to generic questions intended to solicit qualitative comments. Topics covered will include:

1 KEY ISSUES
2 ENGINEERING
3 COMPANY OVERVIEW AND ORGANIZATIONAL CHARACTERISTICS
4 MARKUPS AND PROFITABILITY
5 FINANCIAL PARAMETERS
6 SHIPMENTS PROJECTIONS AND MARKET SHARES
7 PRODUCT MIX
8 DISTRIBUTION CHANNELS
9 CONVERSION COSTS
10 CUMULATIVE REGULATORY BURDEN
11 DIRECT EMPLOYMENT IMPACT ASSESSMENT
12 CAPACITY/ OUTSOURCING/ FOREIGN COMPETITION
13 CONSOLIDATION
14 IMPACTS ON SMALL BUSINESS

Note: Proprietary cost information has been redacted from this public version of the interview guide. Throughout this document, redacted information is indicated with "[R]."

1 Key Issues

DOE is interested in understanding the impact of energy conservation standards on manufacturers. This section provides an opportunity for manufacturers to identify high-priority issues that DOE should take into consideration when conducting the Manufacturer Impact Analysis.

1.1 In general, what are the key concerns for your company regarding this Residential Boiler rulemaking?

1.2 For the issues identified, how significant are they for different product classes and/or efficiency levels?

1.3 How would energy conservation standards affect your ability to compete in the marketplace?

2 Engineering

2.1 For the NOPR analysis, DOE identified the design features in Table 2.1 as those that impact energy use and are generally incorporated into "baseline" (i.e., minimum efficiency) residential boilers in each product class. These features are reflected in DOE's estimates of the manufacturer production cost at the baseline efficiency levels in each product class. Please comment on the characteristics shown in Table 2.1. In addition, Table 2.2 shows the technologies that DOE identified that increase the AFUE of the residential boilers. Please also comment on these technologies.

Table 2-1 Baseline Design Features by Product Class

Product Class	Characteristics	Manufacturer Feedback
Gas-Hot Water	• Natural Draft • Single-stage burner • Electronic Ignition • Cast iron sectional heat exchanger OR copper tube heat exchanger • PSC direct-drive pump motor • Automatic means of adjusting water temperature • Damper	
Gas Steam	• Natural Draft • Single-stage burner • Electronic Ignition • Cast iron sectional heat exchanger • Damper	
Oil Hot Water	• Forced Draft • Third party burner • Electronic Ignition • Cast iron sectional heat exchanger • Automatic means of adjusting water temperature • PSC direct-drive pump motor • Damper	
Oil Steam	• Forced Draft • Third-party burner • Electronic Ignition • Cast iron sectional heat exchanger • Damper	

Table 2-2 Design Features for Increasing Residential Boiler AFUE

Technology	Design Features	Manufacturer Feedback
Heat Exchanger Improvements	Secondary HEX	
	Increased HEX surface area	
	HEX baffles and surface features (e.g. dimples)	
	Use of HEX coatings or corrosive resistant materials	
	Use of draft inducer fan	
Burner Improvements	Two-stage or modulating burners	
	Premix burners	
Other	Direct vent	
	Burner derating	

2.2 How do design options vary by product class and capacity? Are there technical or other factors that make the cost of implementing a given technology higher for some product classes or product capacities than for others? In particular, how do designs for increasing the efficiency of steam boilers differ from hot water boilers?

2.3 How does heat exchanger technology vary by product class and efficiency level?

2.4 Please comment on the estimates of manufacturer production cost (MPC) shown in tables 2.3 through 2.6 below. DOE defines manufacturer production cost as all direct costs associated with manufacturing a product. It includes direct labor, direct materials, and overhead (including depreciation costs). Are there technical or other factors that make the cost of implementing a given technology higher for some product classes or product capacities than for others? In particular, how do designs for increasing the efficiency of steam boilers differ from hot water boilers?

Table 2-3 Estimated Manufacturer Production Costs for Hot-Water Gas Boilers

Efficiency Level	MPC 2013$	Manufacturer Feedback
Baseline (AFUE=82%)	[R]	
1 (AFUE=83%)	[R]	
2 (AFUE=84%)	[R]	
3 (AFUE=85%)	[R]	
4 (AFUE=90%)	[R]	

5 (AFUE=92%)	[R]	
6 (AFUE=96%)	[R]	

Table 2-4 Estimated Manufacturer Production Costs for Hot-Water Oil Boilers

Efficiency Level	MPC 2013$	Manufacturer Feedback
Baseline (AFUE=84%)	[R]	
1 (AFUE=85%)	[R]	
2 (AFUE=86%)	[R]	
3 (AFUE=91%)	[R]	

Table 2-5 Estimated Manufacturer Production Costs for Steam Gas Boilers

Efficiency Level	MPC 2013$	Manufacturer Feedback
Baseline (AFUE=80%)	[R]	
1 (AFUE=82%)	[R]	
2 (AFUE=83%)	[R]	

Table 2-6 Estimated Manufacturer Production Costs for Steam Oil Boilers

Efficiency Level	MPC 2013$	Manufacturer Feedback
Baseline (AFUE=82%)	[R]	
1 (AFUE=84%)	[R]	
2 (AFUE=85%)	[R]	
3 (AFUE=86%)	[R]	

2.5 DOE estimated the cost of the inducer fan differential to be $94.20 which includes the cost of the fan assembly and mounting, vent and pressure switch, draft hood and vent connector, minus the cost of a damper. The MPCs listed above do not include the cost associated with induced draft. In lieu of choosing and efficiency level that would require induced draft, DOE surveyed the market and found the percentage of models at each efficiency level that currently utilize a fan-assisted draft, and assumed that under amended standards that percentage would be unchanged. DOE incorporated the cost of the induced draft percentage at each efficiency level in the LCC analysis. Is this a valid assumption? Would you expect the number of models with fan-assisted draft at a given efficiency level to increase or decrease if an amended standard was set at that level?

Section 310(3) of EISA 2007 amended EPCA to require that a final rule must, if justified by the criteria for adoption of standards in section 325(o) of EPCA, incorporate standby mode and off mode energy use when DOE adopts new or amended standards for certain covered products after July 1, 2010.

(42 U.S.C. 6295(gg)(3)) DOE plans to address the standby mode and off mode energy use in this rulemaking. As directed in the residential furnace and boilers test procedures final rule published in 2010, DOE defines standby mode and off mode for residential boilers as:

- Standby mode means the condition during the heating season in which the furnace or boiler is connected to the power source, and neither the burner, electric resistance elements, nor any electrical auxiliaries such as blowers or pumps, are activated.
- Off mode means the condition during the non-heating season in which the furnace or boiler is connected to the power source, and neither the burner, electric resistance elements, nor any electrical auxiliaries such as blowers or pumps, are activated. 74 FR 36970.

DOE has observed that residential boilers generally do not have a seasonal off switch and therefore assumed that the standby mode and off mode power consumption are equal. DOE has found that certain high efficiency boiler models are equipped with service switches however these are generally not used to turn off the device in the non-heating season.

2.6 In most rulemakings, the baseline is determined by the current Federal minimum energy conservation standard. However, because this is the first rulemaking to regulate the standby and off mode energy consumption of residential boilers, DOE instead established the baseline model for the standby mode and off mode analysis as the most energy-consumptive product. Table 2-7 below lists the baseline standby mode and off mode power consumption for residential boilers. DOE defined and identified baseline components as those that consume the most electricity during standby mode and off mode operation. The most consumptive baseline components were then "assembled" to model the electrical system of a boiler with the maximum system off mode electrical energy consumption from DOE's representative test data. Would you please comment on these standby power consumption estimates for each component?

Table 2-7 Baseline Standby Mode and Off Mode Power Consumption by Component for Boilers in NOPR

	Standby Mode and Off Mode Power Consumption (watts)					
Component	**Gas Hot Water**	**Oil Hot Water**	**Gas Fired Steam**	**Oil Fired Steam**	**Electric Hot Water**	**Electric Steam**
Transformer	4	4	4	4	4	4
ECM Burner Motor	1	N/A	N/A	N/A	N/A	N/A
Controls	2.5	2.5	2.5	2.5	2.5	2.5
Display	4	4	4	4	4	4
Oil Burner	N/A	3	N/A	3	N/A	N/A
Total (watts)	11.5	13.5	10.5	13.5	10.5	10.5

2.7 Is standby power consumption related to certain performance characteristics (e.g., AFUE or input

capacity? If so, please describe the relationship.

2.8 Which components consume power in standby mode (e.g., ignition elements, power supply, transformer, control components/board(s) for the boiler and pumps, etc.)? Can you estimate the magnitude of consumption by component?

2.9 Do your products typically have off switches? If so, are these used to turn off the boilers seasonally?

2.10 Table 2-9 shows the technologies that DOE identified to reduce standby and off mode power consumption for residential boilers. Please comment on these technologies.

Table 2-8 Technology Options for Reducing Standby Off Mode Energy Consumption

Design Features	Manufacturer Feedback
Transformer Improvements	
Switch mode power supplies	

2.11 Please comment on the estimates of manufacturer production cost (MPC) shown in tables 2-10 through 2-15 below.

Table 2-9 Estimated Manufacturer Production Costs for Gas-Fired Hot Water Boilers Standby

Efficiency Level	Description	MPC 2013$	Manufacturer Feedback
Baseline	Linear Power Supply	[R]	
EL1	Linear Power Supply with LLTX	[R]	
EL2	Switching Mode Power Supply	[R]	
EL3	Switching Mode Power Supply with LLTX	[R]	

Table 2-10 Estimated Manufacturer Production Costs for Gas-Fired Steam Boilers Standby

Efficiency Level	Description	MPC 2013$	Manufacturer Feedback
Baseline	Linear Power Supply	[R]	
EL1	Linear Power Supply with LLTX	[R]	
EL2	Switching Mode Power Supply	[R]	
EL3	Switching Mode Power Supply with LLTX	[R]	

Table 2-11 Estimated Manufacturer Production Costs for Oil-Fired Hot Water Boilers Standby

Efficiency Level	Description	MPC 2013$	Manufacturer Feedback
Baseline	Linear Power Supply	[R]	
EL1	Linear Power Supply with LLTX	[R]	
EL2	Switching Mode Power Supply	[R]	
EL3	Switching Mode Power Supply with LLTX	[R]	

Table 2-12 Estimated Manufacturer Production Costs for Oil-Fired Steam Boilers Standby

Efficiency Level	Description	MPC 2013$	Manufacturer Feedback
Baseline	Linear Power Supply	[R]	
EL1	Linear Power Supply with LLTX	[R]	
EL2	Switching Mode Power Supply	[R]	
EL3	Switching Mode Power Supply with LLTX	[R]	

Table 2-13 Estimated Manufacturer Production Costs for Electric Hot Water Boilers Standby

Efficiency Level	Description	MPC 2013$	Manufacturer Feedback
Baseline	Linear Power Supply	[R]	
EL1	Linear Power Supply with LLTX	[R]	
EL2	Switching Mode Power Supply	[R]	
EL3	Switching Mode Power Supply with LLTX	[R]	

Table 2-14 Estimated Manufacturer Production Costs for Electric Steam Boilers Standby

Efficiency Level	Description	MPC 2013$	Manufacturer Feedback
Baseline	Linear Power Supply	[R]	
EL1	Linear Power Supply with LLTX	[R]	
EL2	Switching Mode Power Supply	[R]	
EL3	Switching Mode Power Supply with LLTX	[R]	

3 Company Overview And Organizational Characteristics

3.1 Do you have a parent company and/or subsidiary? If so, please provide their name(s).

3.2 What is your company's approximate market share for Residential Boiler products? Does this vary significantly for any particular product class that you manufacture?

3.3 What are your product line niches and relative strengths in the Residential Boiler market?

3.4 What percentage of your overall revenue is from Residential Boiler sales?

3.5 What is your market share in the industry?

3.6 What are the approximate market shares of the major Residential Boiler manufacturers?

3.7 What other products do you manufacture in addition to Residential Boiler products? Do you produce them in the same facilities as your Residential Boiler products?

3.8 Where are your production facilities located, and what type of product is manufactured at each location? Please provide production figures for your company's manufacturing at each location by product class.

Table 3-8 Manufacturing locations

Location	Product Class	Employees (Production)	Employees (Non-production)	Units/Yr Produced

3.9 Are higher efficiency products built at different plants than lower efficiency products of the same product class?

4 Markups And Profitability

One of the primary objectives of the Manufacturer Impact Analysis (MIA) is to assess the impact of energy conservation standards on industry profitability. In this section, DOE would like to understand the markup structure of the industry and how setting an energy conservation standard would impact your company's markup structure and profitability.

The manufacturer markup is a multiplier applied to manufacturer production cost to cover per unit research and development; selling, general, and administrative expenses; and profit. It is NOT a profit margin. The manufacturer production cost multiplied by the manufacturer markup plus the shipping costs accounts for all costs involved in manufacturing the product, as well as profit.

4.1 Based on prior rulemaking analysis of Residential Boiler products, DOE assumed a markup of 1.41 for all product classes. Please comment on the accuracy of this figure and whether or not it varies significantly by product class.

Table 4-1 Residential Boiler Markups

Product Class	Markup
Gas Hot Water	
Gas Steam	
Oil Hot Water	
Oil Steam	
Electric Hot Water	
Electric Steam	

4.2 Within each product class, do the per-unit mark-ups vary by efficiency level? Is the markup on incremental costs for more efficient designs different than the markup for baseline models?

4.3 What factors besides efficiency affect markups for products that are in the same product class?

4.4 Would you expect energy conservation standards to affect your profitability? If so, please explain why.

5 Financial Parameters

Navigant Consulting, Inc. (NCI) has developed a "straw man" model of financial performance called the Government Regulatory Impact Model (GRIM) using publicly available data. This section attempts to understand how your company's financial situation differs from our industry aggregate picture.

Please compare your company's financial parameters to the GRIM parameters tabulated below.

Table 5-1 Financial Parameters for Residential Boilers Manufacturers

GRIM Input	Definition	Industry Estimated Value	Your Actual
Income Tax Rate	Corporate effective income tax paid (percentage of earnings before taxes, EBT)	32%	
Discount Rate	Weighted average cost of capital (inflation-adjusted weighted average of corporate cost of debt and return on equity)	8.0%	
Working Capital	Current assets less current liabilities (percentage of revenues)	23%	
SG&A	Selling, general, and administrative expenses (percentage of revenues)	20%	
R&D	Research and development expenses (percentage of revenues)	1.6%	
Depreciation	Amortization of fixed assets (percentage of revenues)	2.1%	
Capital Expenditures	Outlay of cash to acquire or improve capital assets (percentage of revenues, not including acquisition or sale of business units)	2.4%	
Cost of Goods Sold	Includes material, labor, overhead, and depreciation (percentage of revenues)	71%	

5.1 Are the figures in Table 7-1 representative of the Residential Boiler industry as a whole? If not, why?

5.2 Do any of the financial parameters in Table 7-1 change for a particular subgroup of manufacturers? Please describe any differences.

6 Shipments Projections and Market Shares

An amended energy conservation standard can change overall shipments by altering product attributes, marketing approaches, product availability, and price. The industry revenue calculations are based on the shipment projections developed by DOE's shipments model. The shipments model includes forecasts for the base case shipments (i.e., total industry shipments absent amended energy conservation standards) and standards case shipments (i.e., total industry shipments with amended energy conservation standards).

6.1 Are residential boiler shipments expected to follow historical trends? Do you anticipate growth and contraction in the markets for each product class over the next decade?

6.2 Do you expect the average efficiency of equipment sold to change over time in the absence of amended conservation standards? If so, please explain why.

7 Product Mix

Product mix describes the distribution of current shipments by efficiency level. Changes in the product mix due to amended energy conservation standards can have a large impact on industry revenues. Having an accurate estimate of the current product mix allows DOE to better estimate how revenues might change due to amended energy conservation standards.

7.1 Could you provide a description of your company's product lines and their respective efficiency levels?

7.2 How would your company's equipment mix and marketing strategy change in response to changes in efficiency standards?

7.3 Would you expect your market share to change if DOE were to amend the efficiency standards?

7.4 Could amended combustion efficiency standards disproportionately advance or harm the competitive position of some firms? If so, why?

7.5 Beyond price and energy efficiency, could new standards result in equipment that will be more or less desirable to consumers or users due to changes in equipment functionality, utility, or other features?

7.6 An amended energy conservation standard affects the product mix by eliminating the sale of products below the minimum efficiency level. DOE assumes that all products that fall below the standard would roll-up to the efficiency level set by an amended energy conservation standard. DOE assumes the distribution of efficiencies above the efficiency level set by the energy

conservation standards will not change. In other words, those customers already purchasing more-efficient products will continue to do so irrespective of amended energy conservation standards. How do you think amended energy conservation standards will affect the sale of more efficient products?

8 Distribution channels

8.1 What are the primary distribution channels for Residential Boilers?

8.2 What percentages of Residential Boilers are sold through each channel?

9 Conversion Costs

An increase in energy conservation standards may cause the industry to incur capital and product conversion costs to meet the energy conservation standard. The MIA considers three types of conversion expenditures:

- Capital conversion costs – One-time investments in plant, property, and equipment (PPE) necessitated by an energy conservation standard. These may be incremental changes to existing PPE or the replacement of existing PPE. Included are expenditures on buildings, equipment, and tooling.
- Product conversion costs – One-time investments in research, product development, testing, marketing and other costs for redesigning products necessitated by an energy conservation standard.
- Stranded assets – Assets replaced before the end of their useful lives as a direct result of the change in energy conservation standard.

With a detailed understanding of the conversion costs necessitated by different standard levels, DOE can better model the impact on the Residential Boiler industry resulting from amendments to the energy conservation standard.

9.1 At your manufacturing facilities, would potential energy conservation standards be difficult to implement? If so, would your company modify existing facilities or develop new facilities?

9.2 What level of conversion costs do you anticipate incurring with each design option? Please provide dollar amounts as well as descriptions of the kind of changes that would need to be implemented in production lines and production facilities.

Table 9-2 Residential Boiler Conversion Costs

Gas-Fired Hot Water Boilers (100,000 Btu/h input)

Efficiency Level	AFUE	Capital Conversion Cost	Product Conversion Cost	Stranded Assets	Overview of Changes
Baseline	82%				
EL 1	83%				
EL 2	84%				
EL 3	85%				
EL 4	90%				
EL 5	92%				
EL6	96%				

Gas-Fired Steam Boilers (100,000 Btu/h input)

Efficiency Level	AFUE	Capital Conversion Cost	Product Conversion Cost	Stranded Assets	Overview of Changes
Baseline	80%				
EL 1	82%				
EL 2	83%				

Oil-Fired Hot Water Boilers (140,000 Btu/h input)

Efficiency Level	AFUE	Capital Conversion Cost	Product Conversion Cost	Stranded Assets	Overview of Changes
Baseline	84%				
EL 1	85%				
EL 2	86%				
EL 3	91%				

Oil-Fired Steam Boilers (140,000 Btu/h input)

Efficiency Level	AFUE	Capital Conversion Cost	Product Conversion Cost	Stranded Assets	Overview of Changes
Baseline	82%				
EL 1	84%				
EL 2	85%				
EL 3	86%				

9.3 Please comment on any additional stranded assets that may result from an amended energy conservation standard.

9.4 For efficiency levels that would require new production equipment, please describe how much downtime would be required. What impact would downtime have on your business?

9.5 Please provide any additional qualitative information that might help DOE understand the type and nature of your conversion investments, including plant and tooling changes and product development efforts required for different design options.

10 Cumulative Regulatory Burden

Cumulative regulatory burden refers to the burden that industry faces from overlapping effects of new or revised DOE standards, and/or other regulatory actions affecting the same product or industry.

10.1 Are there other recent or impending standards that Residential Boiler manufacturers face from other US federal agencies, State regulators, foreign government agencies, or other standard setting bodies? If so, please identify the regulation and the corresponding possible effective dates for those regulations. Below is a preliminary list of regulations that could possibly affect manufacturers of Residential Boiler equipment. Please provide comments on the listed regulations.

10.2 Are there any additional regulatory burdens that DOE should take into consideration? If so, please identify the regulation, the corresponding effective dates, and your expected compliance cost.

10.3 Under what circumstances would you be able to coordinate expenditures related to these other regulations with an energy conservation standard, thereby lessening the cumulative burden?

11 Direct Employment Impact Assessment

The impact of energy conservation standards on employment is an important consideration in the rulemaking process. This section of the interview guide seeks to explore current trends in Residential Boiler production employment and solicit manufacturer views on how domestic employment patterns might be affected by energy conservation standards.

11.1 Would your domestic employment levels be expected to change significantly under amended energy conservation standards? If so, please identify particular standard levels which may trigger changes in employment.

11.2 Would the workforce skills necessary under amended energy conservation standards require extensive retraining or replacement of employees at your manufacturing facilities?

12 Capacity/ Outsourcing/ Foreign Competition

Disparity between domestic and foreign energy conservation standards could impact exports or imports. Labor content and material changes, resulting from energy conservation standards, may impact sourcing decisions.

12.1 Are your production lines currently running at full capacity? If not, how much excess capacity do you have available?

12.2 How would amended energy conservation standards impact your company's manufacturing capacity, in both the short term and the long term?

12.3 What percentage of your company's Residential Boiler production is domestic?

12.4 Absent amended energy conservation standards, are production facilities being relocated to foreign countries?

12.5 Would amended energy conservation standards impact your domestic vs. foreign manufacturing decision?

12.6 What percentage of the U.S. market for Residential Boiler equipment is imported? Would

amended energy conservation standards have an impact on foreign competition?

12.7 What are alternatives to Residential Boiler equipment? Are these substitute products being imported or manufactured domestically?

13 Consolidation

Energy conservation standards can alter the competitive dynamics of the market. This can include prompting companies to enter or exit the market, or to merge. DOE and the Department of Justice are both interested in any potential reduction in competition that would result from an energy conservation standard.

13.1 Please comment on industry consolidation and related trends over the last 10 years.

13.2 In the absence of amended energy conservation standards, do you expect any industry consolidation? Please describe your expectations.

13.3 How would industry competition change as a result of amended energy conservation standards?

13.4 To your knowledge, are there any niche manufacturers for which the adoption of amended energy conservation standards would have a particularly severe impact?

14 Impacts On Small Business

14.1 The Small Business Association (SBA) denotes a small business in the Residential Boiler industry

as having less than 500 employees.[a] By this definition, is your company considered a small business?

14.2 Below is a list of small business Residential Boiler manufacturers compiled by DOE. Are there any small manufacturers that should be added to this list? Are there specific manufacturers on this list that may be more severely impacted by an energy conservation standard than others?

- ECR International
- Heat Transfer Products
- Peerless Boilers

14.3 Are there any reasons that a small business might be at a disadvantage relative to a larger business under amended energy conservation standards? Please consider such factors as technical expertise, access to capital, bulk purchasing power for materials/components, engineering resources, and any other relevant issues.

14.4 Would small business manufacturers have different incremental impacts from energy conservation standards than the rest of the industry?

[a] DOE uses the SBA small business size standards effective November 5, 2010 to determine whether a company is a small business. To be categorized as a small business, a Residential Boiler manufacturer and its affiliates may employ a maximum of 750 employees. The 750 employee threshold includes all employees in a business's parent company and any other subsidiaries.

CHAPTER 13. EMISSIONS IMPACT ANALYSIS

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CHAPTER 13. EMISSIONS IMPACT ANALYSIS

13.1 INTRODUCTION

The emissions analysis consists of two components. The first component estimates the effect of potential energy conservation standards on power sector and site combustion emissions of carbon dioxide (CO_2), nitrogen oxides (NO_X), sulfur dioxide (SO_2) and mercury (Hg). The second component estimates the impacts of potential standards on emissions of two additional greenhouse gases, methane (CH_4) and nitrous oxide (N_2O), as well as the impacts to emissions of all species due to "upstream" activities in the fuel production chain. These upstream activities comprise extraction, processing, and transporting fuels to the site of combustion. The associated emissions are referred to as upstream emissions. Together, these emissions account for the full-fuel-cycle (FFC), in accordance with DOE's FFC Statement of Policy. 76 FR 51282 (Aug. 18, 2011).

The analysis of power sector emissions uses marginal emissions intensity factors calculated by DOE. As of 2014, DOE is using a new methodology based on results published for the *Annual Energy Outlook 2015 (AEO 2015)* reference case and a set of side cases that implement a variety of efficiency-related policies.[1] The new methodology is described in appendix 13A to this TSD, and in the report "Utility Sector Impacts of Reduced Electricity Demand" (Coughlin, 2014).[2] For site combustion of natural gas or petroleum fuels, the combustion emissions of CO_2 and NO_X are estimated using emissions intensity factors from a publication of the Environmental Protection Agency (EPA).[3]

The emissions intensity factors are expressed in terms of physical units per MWh or MMBtu of site energy savings. Total emissions reductions are estimated by multiplying the emissions intensity factor by the energy savings calculated in the national impact analysis (chapter 10). This chapter presents the results of the emissions analysis. The emissions factors used in the calculations are provided in appendix 13A. For power sector emissions, the factors depend on the sector and end use. The results presented here use factors from the power plant types that supply electricity for space heating in homes and commercial buildings for the AFUE standards, and for refrigeration (base load) for the standby and off mode standards.

For CH_4 and N_2O, DOE calculated emissions reduction in tons and also in terms of units of carbon dioxide equivalent (CO_2eq). Gases are converted to CO_2eq by multiplying each ton of gas by the gas' global warming potential (GWP) over a 100-year time horizon. Based on the Fifth Assessment Report of the Intergovernmental Panel on Climate Change,[a] DOE used GWP values of 28 for CH_4 and 265 for N_2O.

[a] IPCC, 2013: *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Chapter 8.

13.2 AIR QUALITY REGULATIONS AND EMISSIONS IMPACTS

Each annual version of the Annual Energy Outlook (AEO) incorporates the projected impacts of existing air quality regulations on emissions. *AEO 2015* generally represents current Federal and State legislation and final implementation regulations in place as of the end of October 2014. DOE's estimation of impacts accounts for the presence of the emissions control programs discussed in the following paragraphs.

SO_2 emissions from affected electric generating units (EGUs) are subject to nationwide and regional emissions cap and trading programs. Title IV of the Clean Air Act sets an annual emissions cap on SO_2 for affected EGUs in the 48 contiguous states and the District of Columbia (D.C.). SO_2 emissions from 28 eastern states and D.C. were also limited under the Clean Air Interstate Rule (CAIR), which created an allowance-based trading program that that operates along with the Title IV program in those States and D.C. 70 FR 25162 (May 12, 2005). CAIR was remanded to EPA by the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) but parts of it remained in effect. On July 6, 2011 EPA issued a replacement for CAIR, the Cross-State Air Pollution Rule (CSAPR). 76 FR 48208 (August 8, 2011). On August 21, 2012, the D.C. Circuit issued a decision to vacate CSAPR. See *EME Homer City Generation, LP v. EPA*, 696 F.3d 7, 38 (D.C. Cir. 2012). The court ordered EPA to continue administering CAIR. On April 29, 2014, the U.S. Supreme Court reversed the judgment of the D.C. Circuit and remanded the case for further proceedings consistent with the Supreme Court's opinion.[b] On October 23, 2014, the D.C. Circuit lifted the stay of CSAPR.[c] Pursuant to this action, CSAPR went into effect (and CAIR ceased to be in effect) as of January 1, 2015.

EIA was not able to incorporate CSAPR into AEO 2015, so it assumes implementation of CAIR. Although DOE's analysis used emissions factors that assume that CAIR, not CSAPR, is the regulation in force. However, the difference between CAIR and CSAPR is not relevant for the purpose of DOE's analysis of emissions impacts from energy conservation standards.

The attainment of emissions caps is typically flexible among affected Electric Generating Units (EGUs) and is enforced through the use of emissions allowances and tradable permits. Under existing EPA regulations, any excess SO_2 emissions allowances resulting from the lower electricity demand caused by the imposition of an efficiency standard could be used to permit offsetting increases in SO_2 emissions by any regulated EGU. In past rulemakings, DOE recognized that there was uncertainty about the effects of efficiency standards on SO_2 emissions covered by the existing cap-and-trade system, but it concluded that no reductions in power sector emissions would occur for SO_2 as a result of standards.

Beginning in 2016, however, SO_2 emissions will fall as a result of the Mercury and Air Toxics Standards (MATS) for power plants. 77 FR 9304 (Feb. 16, 2012). In the final MATS

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[b] *See EPA v. EME Homer City Generation*, 134 S.Ct. 1584, 1610 (U.S. 2014). The Supreme Court held in part that EPA's methodology for quantifying emissions that must be eliminated in certain States due to their impacts in other downwind States was based on a permissible, workable, and equitable interpretation of the Clean Air Act provision that provides statutory authority for CSAPR.

[c] *See Georgia v. EPA*, Order (*D. C. Cir. filed October 23, 2014) (No. 11-1302)*,

rule, EPA established a standard for hydrogen chloride as a surrogate for acid gas hazardous air pollutants (HAP), and also established a standard for SO_2 (a non-HAP acid gas) as an alternative equivalent surrogate standard for acid gas HAP. The same controls are used to reduce HAP and non-HAP acid gas; thus, SO_2 emissions will be reduced as a result of the control technologies installed on coal-fired power plants to comply with the MATS requirements for acid gas. *AEO 2015* assumes that, in order to continue operating, coal plants must have either flue gas desulfurization or dry sorbent injection systems installed by 2016. Both technologies, which are used to reduce acid gas emissions, also reduce SO_2 emissions. Under the MATS, emissions will be far below the cap established by CAIR, so it is unlikely that excess SO_2 emissions allowances resulting from the lower electricity demand would be needed or used to permit offsetting increases in SO_2 emissions by any regulated EGU.[d] Therefore, DOE believes that efficiency standards will reduce SO_2 emissions in 2016 and beyond.

CAIR established a cap on NO_x emissions in 28 eastern States and the District of Columbia.[e] Energy conservation standards are expected to have little effect on NO_x emissions in those States covered by CSAPR because excess NO_x emissions allowances resulting from the lower electricity demand could be used to permit offsetting increases in NO_x emissions. However, standards would be expected to reduce NO_x emissions in the States not affected by CAIR, so DOE estimated NOx emissions reductions from potential standards for those States.

The MATS limit mercury emissions from power plants, but they do not include emissions caps and, as such, DOE's energy conservation standards would likely reduce Hg emissions. DOE estimated marginal mercury emissions reductions using the reference and side cases published with *AEO 2015*, which incorporate the MATS.

13.3 EMISSIONS IMPACT RESULTS

Table 13.3.1 presents the estimated cumulative emissions reductions for the lifetime of products sold in 2021-2050 for each AFUE TSL. Table 13.3.2 presents similar results for each boiler standby mode and off mode TSL. Negative values indicate that emissions increase.

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[d] DOE notes that the Supreme Court recently remanded EPA's 2012 rule regarding national emission standards for hazardous air pollutants from certain electric utility steam generating units. See *Michigan v. EPA* (Case No. 14-46, 2015). DOE has tentatively determined that the remand of the MATS rule does not change the assumptions regarding the impact of energy efficiency standards on SO_2 emissions. Further, while the remand of the MATS rule may have an impact on the overall amount of mercury emitted by power plants, it does not change the impact of the energy efficiency standards on mercury emissions. DOE will continue to monitor developments related to this case and respond to them as appropriate.

[e] CSAPR also applies to NO_X and it would supersede the regulation of NO_X under CAIR. As stated previously, the current analysis assumes that CAIR, not CSAPR, is the regulation in force. The difference between CAIR and CSAPR with regard to DOE's analysis of NO_X emissions is slight.

Table 13.3.1 Cumulative Emissions Reduction for Potential Standards for AFUE Standards*

	TSL				
	1	**2**	**3**	**4**	**5**
Power Sector and Site Emissions					
CO_2 (million metric tons)	3.38	5.53	8.14	37.70	75.50
SO_2 (thousand tons)	0.672	1.84	1.94	2.40	3.45
NO_X (thousand tons)	37.9	98.4	105	355	408
Hg (tons)	0.000	0.000	0.000	-0.014	-0.011
CH_4 (thousand tons)	0.084	0.157	0.216	0.502	1.382
N_2O (thousand tons)	0.031	0.076	0.084	0.228	0.321
Upstream Emissions					
CO_2 (million metric tons)	0.497	0.821	1.19	6.06	11.41
SO_2 (thousand tons)	0.046	0.125	0.131	0.362	0.402
NO_X (thousand tons)	7.37	11.5	17.4	92.2	178
Hg (tons)	0.000	0.000	0.000	0.000	0.000
CH_4 (thousand tons)	32.6	37.2	71.7	452	964
N_2O (thousand tons)	0.002	0.006	0.006	0.022	0.032
Total Emissions					
CO_2 (million metric tons)	3.88	6.35	9.33	43.76	86.90
SO_2 (thousand tons)	0.718	1.97	2.07	2.76	3.85
NO_X (thousand tons)	45.3	110	122	447	586
Hg (tons)	0.000	0.000	0.000	-0.014	-0.011
CH_4 (thousand tons)	32.7	37.4	71.9	452	965
CH_4 (thousand tons CO_2eq)**	914	1046	2013	12662	27023
N_2O (thousand tons)	0.033	0.082	0.091	0.249	0.352
N_2O (thousand tons CO_2eq)**	8.73	21.7	24.0	66.0	93.3

* Negative values refer to an increase in emissions.
* CO_2eq is the quantity of CO_2 that would have the same global warming potential (GWP).

Table 13.3.2 Cumulative Emissions Reduction for Potential Standards for Standby and Off Mode Standards

	TSL		
	1	2	3
Power Sector and Site Emissions			
CO_2 (million metric tons)	0.052	0.072	0.144
SO_2 (thousand tons)	0.031	0.043	0.085
NO_X (thousand tons)	0.057	0.080	0.160
Hg (tons)	0.000	0.000	0.000
CH_4 (thousand tons)	0.004	0.006	0.012
N_2O (thousand tons)	0.001	0.001	0.002
Upstream Emissions			
CO_2 (million metric tons)	0.003	0.004	0.008
SO_2 (thousand tons)	0.001	0.001	0.002
NO_X (thousand tons)	0.042	0.059	0.119
Hg (tons)	0.000	0.000	0.000
CH_4 (thousand tons)	0.234	0.328	0.656
N_2O (thousand tons)	0.000	0.000	0.000
Total Emissions			
CO_2 (million metric tons)	0.055	0.076	0.153
SO_2 (thousand tons)	0.031	0.043	0.087
NO_X (thousand tons)	0.099	0.139	0.278
Hg (tons)	0.000	0.000	0.000
CH_4 (thousand tons)	0.239	0.334	0.669
CH_4 (thousand tons CO_2eq)*	6.69	9.36	18.7
N_2O (thousand tons)	0.001	0.001	0.002
N_2O (thousand tons CO_2eq)*	0.172	0.240	0.481

* CO_2eq is the quantity of CO_2 that would have the same global warming potential (GWP).

Figure 13.3.1 through Figure 13.3.5 show the annual reductions of emissions for each type of emission and from each AFUE TSL. Figure 13.3.7 through Figure 13.3.12 present similar results for standby mode and off mode TSLs. The reductions reflect the lifetime impacts of products sold in 2021-2050.

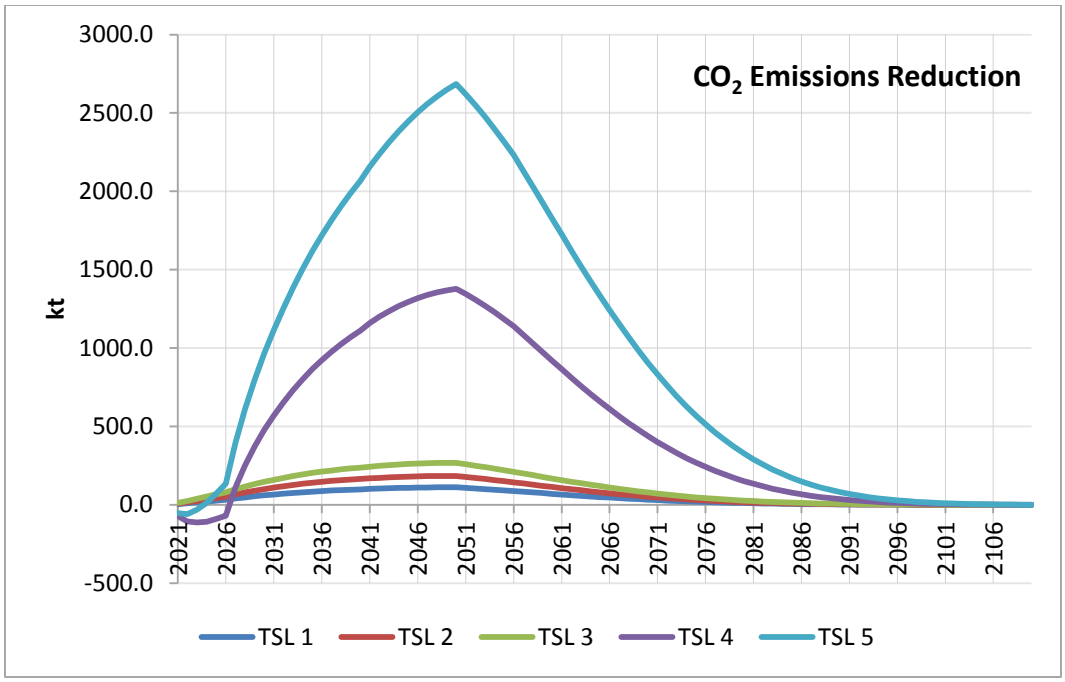

Figure 13.3.1 CO_2 Total Emissions Reduction for AFUE Standards

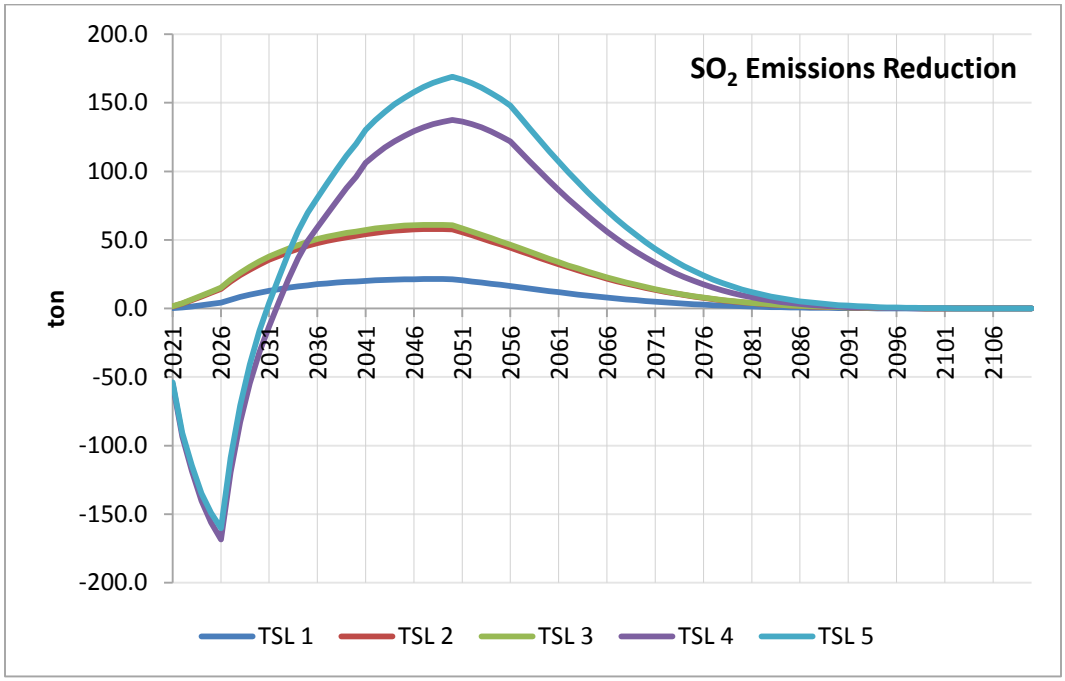

Figure 13.3.2 SO_2 Total Emissions Reduction for AFUE Standards

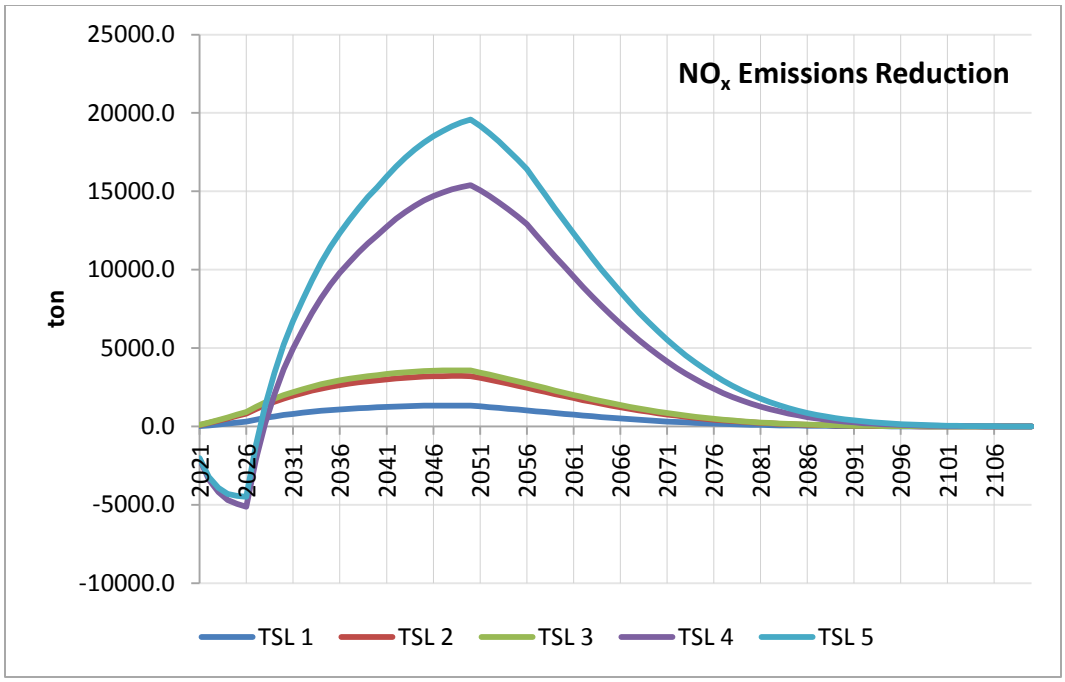

Figure 13.3.3 NO_x Total Emissions Reduction for AFUE Standards

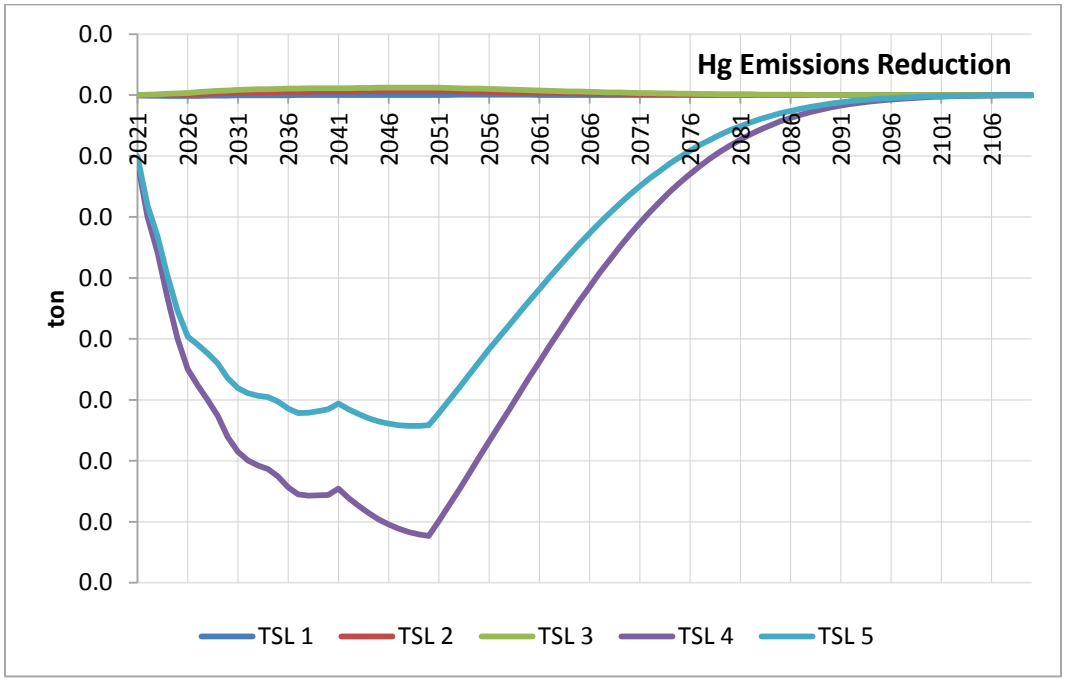

Figure 13.3.4 Hg Total Emissions Reduction for AFUE Standards

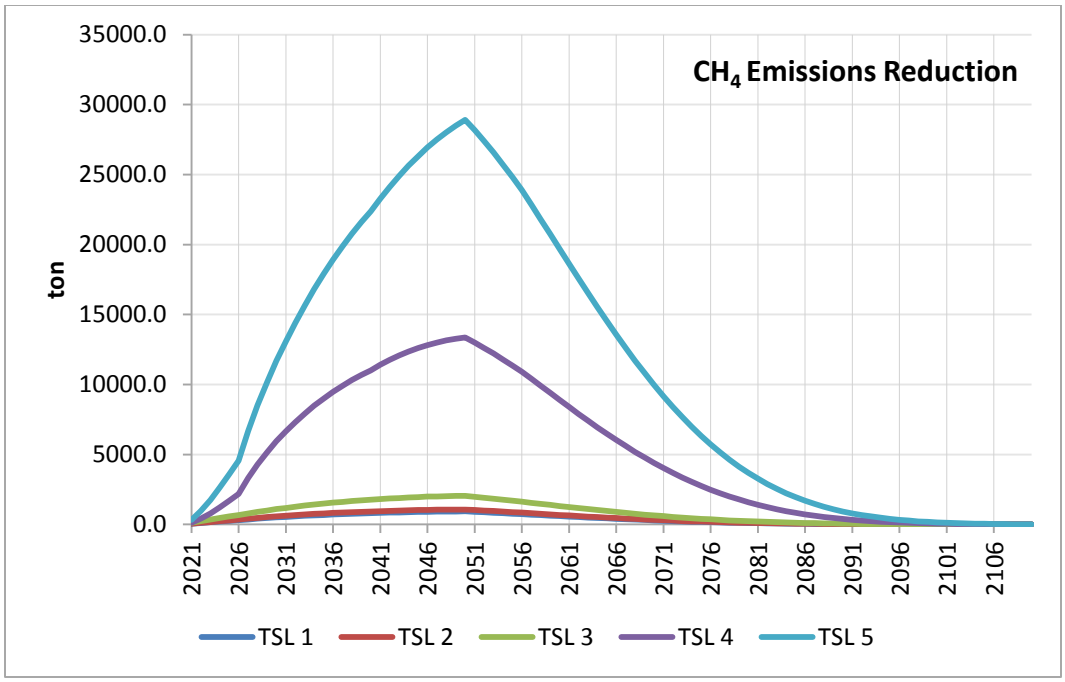

Figure 13.3.5 CH_4 Total Emissions Reduction for AFUE Standards

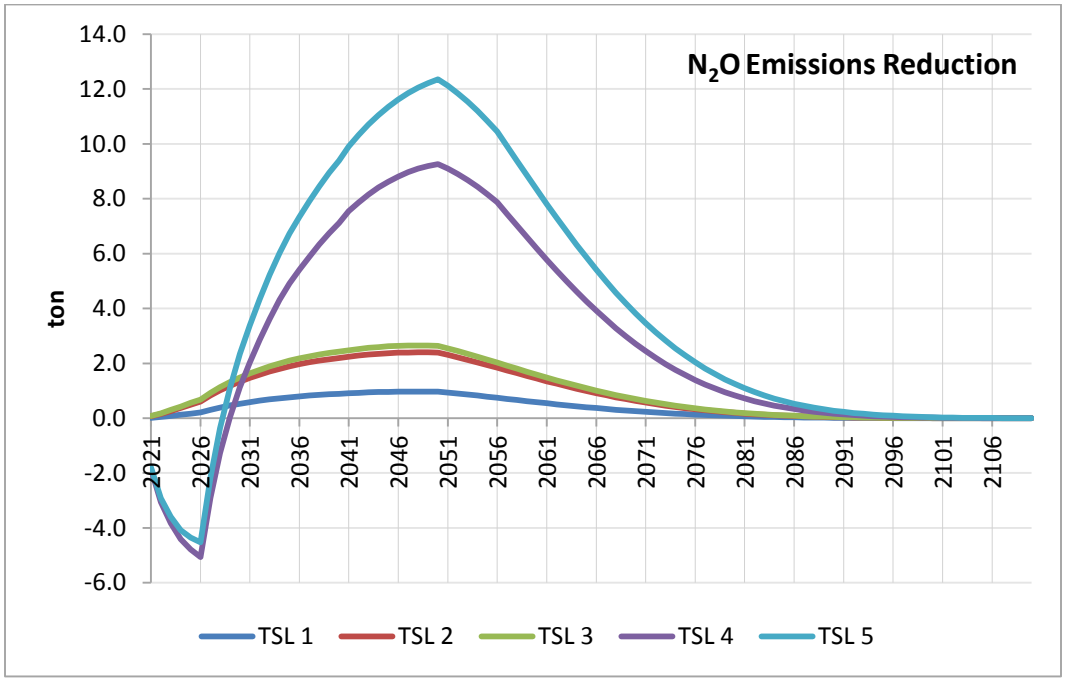

Figure 13.3.6 N_2O Total Emissions Reduction for AFUE Standards

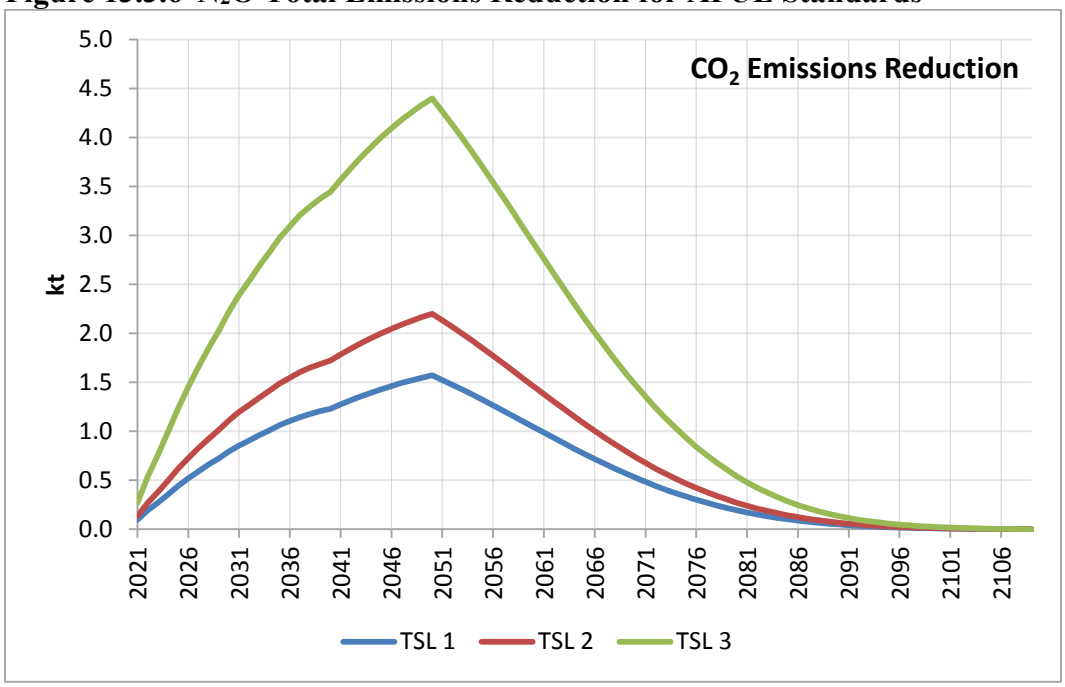

Figure 13.3.7 CO_2 Total Emissions Reduction for Standby and Off Mode Standards

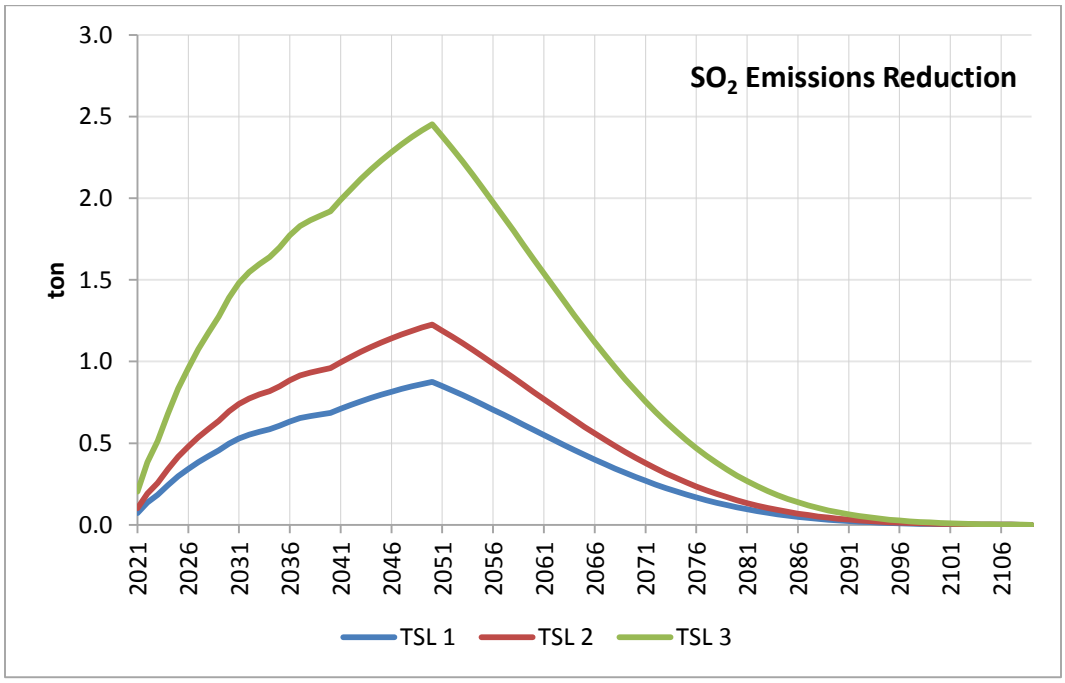

Figure 13.3.8 SO_2 Total Emissions Reduction for Standby and Off Mode Standards

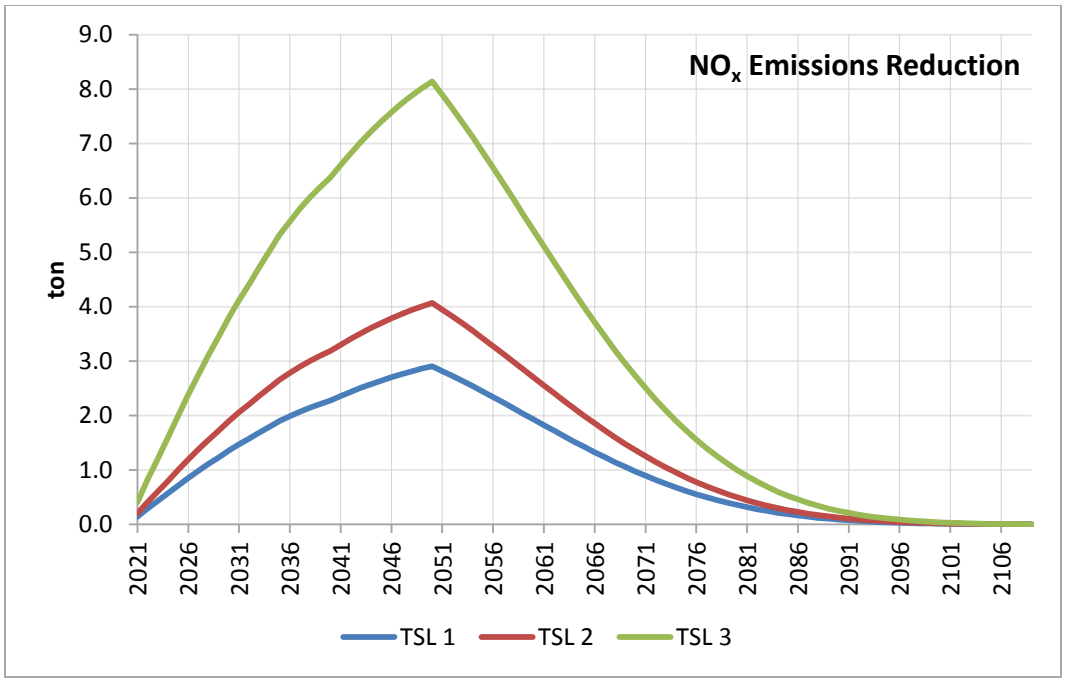

Figure 13.3.9 NO_x Total Emissions Reduction for Standby and Off Mode Standards

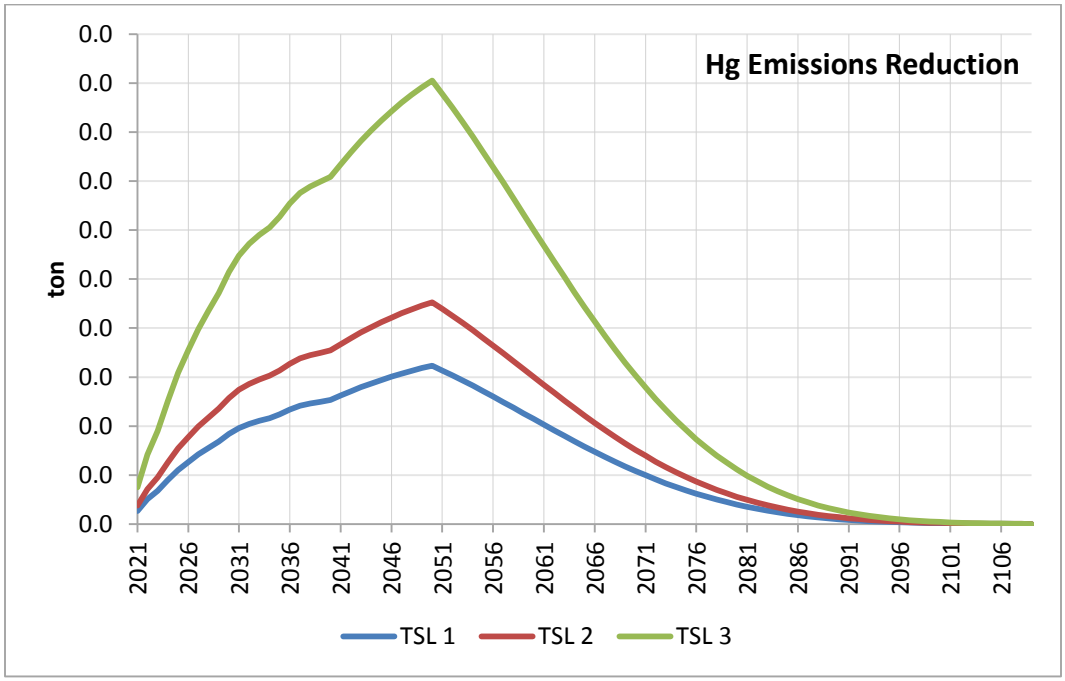

Figure 13.3.10 Hg Total Emissions Reduction for Standby and Off Mode Standards

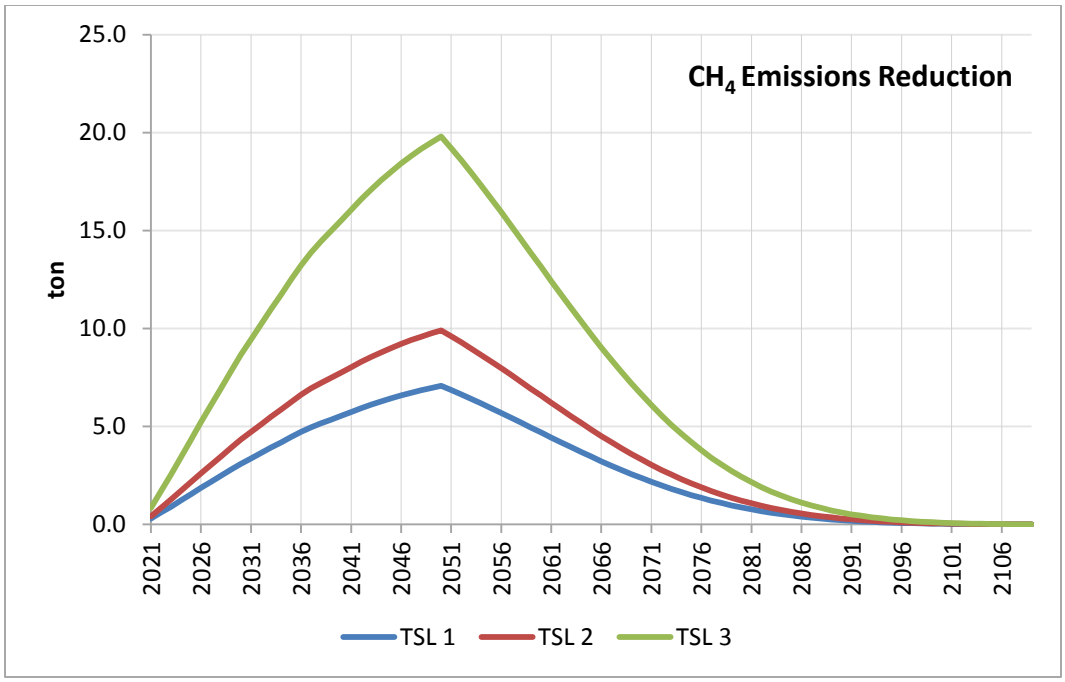

Figure 13.3.11 CH_4 Total Emissions Reduction for Standby and Off Mode Standards

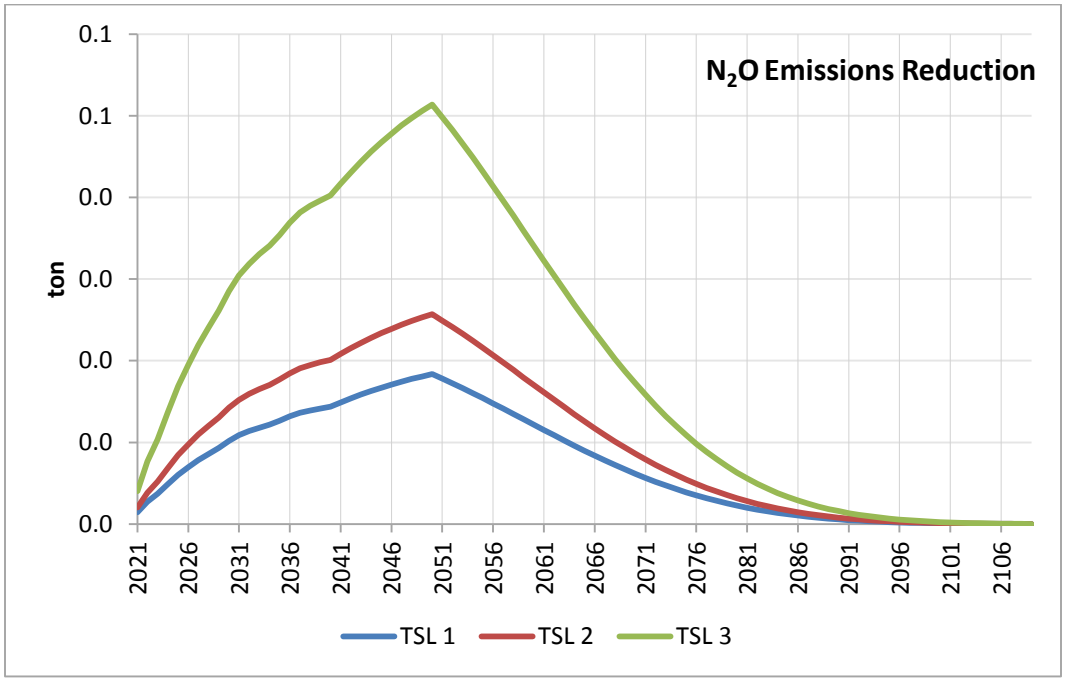

Figure 13.3.12 N_2O Total Emissions Reduction for Standby and Off Mode Standards

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APPENDIX 13A. EMISSIONS ANALYSIS METHODOLOGY

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APPENDIX 13A. EMISSIONS ANALYSIS METHODOLOGY

13A.1 INTRODUCTION

The emissions analysis consists of two components. The first component estimates the effect of potential energy conservation standards on power sector and site combustion emissions of carbon dioxide (CO_2), nitrogen oxides (NO_X), sulfur dioxide (SO_2) and mercury (Hg). The second component estimates the impacts of a potential standard on emissions of two additional greenhouse gases, methane (CH_4) and nitrous oxide (N_2O), as well as the reductions to emissions of all species due to "upstream" activities in the fuel production chain. These upstream activities comprise extraction, processing, and transporting fuels to the site of combustion. The associated emissions are referred to as upstream emissions. Together, these emissions account for the full-fuel-cycle (FFC), in accordance with DOE's FFC Statement of Policy. 76 FR 51282 (Aug. 18, 2011).

The analysis of power sector emissions uses marginal emissions intensity factors calculated by DOE. As of 2014, DOE uses a methodology based on results published with the most recent edition of the *Annual Energy Outlook (AEO)* which is published by the Energy Information Agency (EIA). For this analysis DOE used the version published in May 2015 (*AEO 2015*).[1] The *AEO* includes a reference case and a set of side cases that implement a variety of economic and policy scenarios. In 2015 the EIA announced the adoption of a two-year release cycle for the AEO, alternating between a full set of scenarios and a shorter edition containing only five alternate scenarios. As the *AEO 2015* is a shorter edition, DOE has adapted its calculation methodology accordingly.

DOE developed end-use specific emissions intensity coefficients, in units of mass of pollutant per kWh of site electricity, for each pollutant. The methodology is based on the more general approach used for all the utility sector impacts calculations, which is described in appendix 15A of this TSD and in the report "Utility Sector Impacts of Reduced Electricity Demand" (Coughlin, 2014).[2] This appendix describes the methodology used to estimate the upstream emissions factors, and presents the values used for all emissions factors.

13A.2 POWER SECTOR AND SITE EMISSIONS FACTORS

Power sector marginal emissions factors are calculated by looking at the difference, over the full analysis period, between the AEO reference case and the policy side cases. The analysis produces a set of emissions intensity factors that quantify the reduction in emissions of a given pollutant per unit reduction of site consumption of electricity. Distinct factors are calculated for the residential and commercial sectors, and for each of the end uses that are modeled explicitly in NEMS as listed in the tables below. Total emissions reductions are estimated by multiplying the intensity factors times the energy savings calculated in the national impact analysis (chapter 10). Power sector emissions factors are presented in Table 13A.4.2 through Table 13A.4.7.

Site combustion of fossil fuels in buildings (for example in water-heating, space-heating or cooking applications) also produces emissions of CO_2 and other pollutants. To quantify the

reduction in these emissions from a considered standard level, DOE used emissions intensity factors from Environmental Protection Agency (EPA) publications.[3] These factors, presented in Table 13A.4.1, are constant in time.

13A.3 UPSTREAM FACTORS

The FFC upstream emissions are estimated based on the methodology developed by Coughlin (2013).[4] The upstream emissions include both emissions from fuel combustion during extraction, processing and transportation of fuel, and "fugitive" emissions (direct leakage to the atmosphere) of CH_4 and CO_2.

The FFC accounting approach is described briefly in appendix 10B and in Coughlin (2013).[4] When demand for a particular fuel is reduced, there is a corresponding reduction in the upstream activities associated with production of that fuel (mining, refining etc.) These upstream activities also consume energy and therefore produce combustion emissions. The FFC accounting estimates the total consumption of electricity, natural gas and petroleum-based fuels in these upstream activities. The relevant combustion emissions factors are then applied to this fuel use to determine the total upstream emissions intensities from combustion, per unit of fuel delivered to the consumer.

In addition to combustion emissions, extraction and processing of fossil fuels also produces fugitive emissions of CO_2 and CH_4. Fugitive emissions of CO_2 are small relative to combustion emissions, comprising about 2-3 percent of total CO_2 emissions for natural gas and 1-2 percent for petroleum fuels. In contrast, the fugitive emissions of methane from fossil fuel production are relatively large compared to combustion emissions of CH_4. Hence, fugitive emissions make up over 99 percent of total methane emissions for natural gas, about 95 percent for coal, and 93 percent for petroleum fuels.

Fugitive emissions factors for CO_2 and methane from coal mining and natural gas production were estimated based on a review of recent studies compiled by Burnham (2011).[5] This review includes estimates of the difference between fugitive emissions factors for conventional production of natural vs. unconventional (shale or tight gas). These estimates rely in turn on data gathered by EPA under new GHG reporting requirements for the petroleum and natural gas industries.[6,7] As more data are made available, DOE will continue to update these estimated emissions factors.

Upstream emissions factors account for both fugitive emissions and combustion emissions in extraction, processing, and transport of primary fuels. For ease of application in its analysis, DOE developed all of the emissions factors using site (point of use) energy savings in the denominator. Table 13A.4.1 presents the electricity upstream emissions factors for selected years. The caps that apply to power sector NO_X emissions do not apply to upstream combustion sources, so some components of the upstream fuel cycle (particularly off-road mobile engines) can contribute significantly to the upstream NO_x emissions factors.

13A.4 DATA TABLES

Summary tables of all the emissions factor data used by DOE for rules using *AEO 2015* are presented in the tables below. Table 13A.4.1 provides combustion emissions factors for fuels commonly used in buildings. Table 13A.4.2 to Table 13A.4.7 present the marginal power sector emissions factors as a function of sector and end use for a selected set of years. Table 13A.4.8 to Table 13A.4.10 provide the upstream emissions factors for all pollutants, for site electricity, natural gas and petroleum fuels. In all cases, the emissions factors are defined relative to site use of the fuel.

Table 13A.4.1 Site Combustion Emissions Factors

Species	Natural Gas lb/mmcf	Distillate Oil lb/1000 gal	Propane lb/1000 gal	Kerosene lb/1000 gal
CO_2	1.20E+05	2.25E+04	1.25E+04	2. 24E+04
SO_2	6.00E-01	142*(S)	0.1*(S)	142*(S)
NOx	9.60E+01	1.90E+01	1.40E+01	1.80E+01
N_2O	2.20E+00	1.76E-01	1.10E-01	1.76E-01
CH_4	2.30E+00	9.04E-01	5.95E-01	9.04E-01

Table 13A.4.2 Power Sector Emissions Factors for CO_2 (Tons of CO_2 per kWh of Site Electricity Use)

	2020	2025	2030	2035	2040
Commercial Sector					
cooking	8.06E-04	7.24E-04	6.57E-04	6.05E-04	5.54E-04
lighting	8.10E-04	7.27E-04	6.59E-04	6.07E-04	5.55E-04
office equipment (non-pc)	7.94E-04	7.15E-04	6.49E-04	5.98E-04	5.49E-04
office equipment (pc)	7.94E-04	7.15E-04	6.49E-04	5.98E-04	5.49E-04
other uses	7.99E-04	7.19E-04	6.52E-04	6.01E-04	5.51E-04
refrigeration	8.24E-04	7.37E-04	6.68E-04	6.14E-04	5.61E-04
space cooling	7.85E-04	7.07E-04	6.42E-04	5.93E-04	5.46E-04
space heating	8.34E-04	7.45E-04	6.76E-04	6.20E-04	5.65E-04
ventilation	8.24E-04	7.38E-04	6.69E-04	6.14E-04	5.61E-04
water heating	8.12E-04	7.29E-04	6.61E-04	6.08E-04	5.56E-04
Industrial Sector					
all uses	7.99E-04	7.19E-04	6.52E-04	6.01E-04	5.51E-04
Residential Sector					
clothes dryers	8.12E-04	7.29E-04	6.61E-04	6.08E-04	5.56E-04
cooking	8.05E-04	7.23E-04	6.57E-04	6.04E-04	5.52E-04
freezers	8.23E-04	7.37E-04	6.68E-04	6.14E-04	5.61E-04
lighting	8.23E-04	7.37E-04	6.69E-04	6.14E-04	5.60E-04
other uses	8.11E-04	7.28E-04	6.61E-04	6.08E-04	5.55E-04
refrigeration	8.22E-04	7.36E-04	6.68E-04	6.13E-04	5.61E-04
space cooling	7.86E-04	7.09E-04	6.43E-04	5.94E-04	5.46E-04
space heating	8.31E-04	7.43E-04	6.74E-04	6.18E-04	5.63E-04
water heating	8.13E-04	7.30E-04	6.62E-04	6.09E-04	5.56E-04

Table 13A.4.3 Power Sector Emissions Factors for Hg (tons/TWh)

	2020	2025	2030	2035	2040
Commercial Sector					
cooking	2.14E-03	1.67E-03	1.40E-03	1.18E-03	1.05E-03
lighting	2.15E-03	1.68E-03	1.41E-03	1.19E-03	1.06E-03
office equipment (non-pc)	2.06E-03	1.61E-03	1.36E-03	1.14E-03	1.01E-03
office equipment (pc)	2.06E-03	1.61E-03	1.36E-03	1.14E-03	1.01E-03
other uses	2.09E-03	1.63E-03	1.37E-03	1.15E-03	1.03E-03
refrigeration	2.23E-03	1.74E-03	1.47E-03	1.23E-03	1.10E-03
space cooling	1.97E-03	1.54E-03	1.30E-03	1.08E-03	9.69E-04
space heating	2.31E-03	1.80E-03	1.52E-03	1.27E-03	1.14E-03
ventilation	2.24E-03	1.75E-03	1.47E-03	1.23E-03	1.10E-03
water heating	2.16E-03	1.69E-03	1.42E-03	1.19E-03	1.07E-03
Industrial Sector					
all uses	2.09E-03	1.63E-03	1.37E-03	1.15E-03	1.03E-03
Residential Sector					
clothes dryers	2.18E-03	1.70E-03	1.43E-03	1.20E-03	1.07E-03
cooking	2.15E-03	1.68E-03	1.41E-03	1.18E-03	1.06E-03
freezers	2.23E-03	1.74E-03	1.46E-03	1.23E-03	1.10E-03
lighting	2.25E-03	1.76E-03	1.48E-03	1.24E-03	1.11E-03
other uses	2.18E-03	1.70E-03	1.43E-03	1.20E-03	1.07E-03
refrigeration	2.22E-03	1.74E-03	1.46E-03	1.23E-03	1.10E-03
space cooling	1.99E-03	1.55E-03	1.31E-03	1.09E-03	9.77E-04
space heating	2.30E-03	1.79E-03	1.51E-03	1.27E-03	1.13E-03
water heating	2.20E-03	1.72E-03	1.44E-03	1.21E-03	1.08E-03

Table 13A.4.4 Power Sector Emissions Factors for NO_x (tons/MWh)

	2020	2025	2030	2035	2040
Commercial Sector					
cooking	7.24E-04	6.91E-04	6.44E-04	6.11E-04	5.64E-04
lighting	7.26E-04	6.92E-04	6.46E-04	6.12E-04	5.65E-04
office equipment (non-pc)	7.20E-04	6.88E-04	6.42E-04	6.10E-04	5.63E-04
office equipment (pc)	7.20E-04	6.88E-04	6.42E-04	6.10E-04	5.63E-04
other uses	7.22E-04	6.89E-04	6.43E-04	6.10E-04	5.64E-04
refrigeration	7.32E-04	6.96E-04	6.49E-04	6.15E-04	5.66E-04
space cooling	7.22E-04	6.88E-04	6.41E-04	6.10E-04	5.67E-04
space heating	7.33E-04	6.97E-04	6.51E-04	6.16E-04	5.64E-04
ventilation	7.32E-04	6.96E-04	6.49E-04	6.15E-04	5.66E-04
water heating	7.28E-04	6.93E-04	6.46E-04	6.13E-04	5.65E-04
Industrial Sector					
all uses	7.22E-04	6.89E-04	6.43E-04	6.10E-04	5.64E-04
Residential Sector					
clothes dryers	7.24E-04	6.91E-04	6.45E-04	6.12E-04	5.63E-04
cooking	7.20E-04	6.88E-04	6.43E-04	6.10E-04	5.61E-04
freezers	7.32E-04	6.96E-04	6.49E-04	6.15E-04	5.66E-04
lighting	7.28E-04	6.94E-04	6.48E-04	6.14E-04	5.63E-04
other uses	7.23E-04	6.90E-04	6.45E-04	6.11E-04	5.62E-04
refrigeration	7.31E-04	6.96E-04	6.49E-04	6.15E-04	5.66E-04
space cooling	7.22E-04	6.88E-04	6.41E-04	6.10E-04	5.66E-04
space heating	7.31E-04	6.96E-04	6.50E-04	6.15E-04	5.64E-04
water heating	7.23E-04	6.90E-04	6.44E-04	6.11E-04	5.61E-04

Table 13A.4.5 Power Sector Emissions Factors for SO_2 (tons/MWh)

	2020	2025	2030	2035	2040
Commercial Sector					
cooking	5.75E-04	4.49E-04	3.77E-04	3.16E-04	2.83E-04
lighting	5.79E-04	4.52E-04	3.80E-04	3.19E-04	2.85E-04
office equipment (non-pc)	5.55E-04	4.33E-04	3.64E-04	3.05E-04	2.73E-04
office equipment (pc)	5.55E-04	4.33E-04	3.64E-04	3.05E-04	2.73E-04
other uses	5.62E-04	4.39E-04	3.69E-04	3.09E-04	2.76E-04
refrigeration	6.00E-04	4.69E-04	3.94E-04	3.31E-04	2.96E-04
space cooling	5.30E-04	4.14E-04	3.48E-04	2.92E-04	2.60E-04
space heating	6.21E-04	4.85E-04	4.08E-04	3.42E-04	3.06E-04
ventilation	6.01E-04	4.69E-04	3.95E-04	3.31E-04	2.96E-04
water heating	5.82E-04	4.54E-04	3.82E-04	3.20E-04	2.86E-04
Industrial Sector					
all uses	5.62E-04	4.39E-04	3.69E-04	3.09E-04	2.76E-04
Residential Sector					
clothes dryers	5.87E-04	4.58E-04	3.85E-04	3.23E-04	2.89E-04
cooking	5.77E-04	4.51E-04	3.79E-04	3.18E-04	2.84E-04
freezers	5.99E-04	4.68E-04	3.93E-04	3.30E-04	2.95E-04
lighting	6.06E-04	4.73E-04	3.98E-04	3.34E-04	2.98E-04
other uses	5.87E-04	4.58E-04	3.85E-04	3.23E-04	2.89E-04
refrigeration	5.98E-04	4.67E-04	3.93E-04	3.30E-04	2.95E-04
space cooling	5.35E-04	4.18E-04	3.51E-04	2.94E-04	2.63E-04
space heating	6.17E-04	4.82E-04	4.05E-04	3.40E-04	3.04E-04
water heating	5.91E-04	4.62E-04	3.88E-04	3.26E-04	2.91E-04

Table 13A.4.6 Power Sector Emissions Factors for CH_4 (tons/MWh)

	2020	2025	2030	2035	2040
Commercial Sector					
Cooking	7.79E-05	6.25E-05	5.34E-05	4.57E-05	4.11E-05
Lighting	7.85E-05	6.29E-05	5.38E-05	4.60E-05	4.14E-05
office equipment (non-pc)	7.54E-05	6.05E-05	5.17E-05	4.42E-05	3.98E-05
office equipment (pc)	7.54E-05	6.05E-05	5.17E-05	4.42E-05	3.98E-05
other uses	7.63E-05	6.12E-05	5.23E-05	4.48E-05	4.02E-05
Refrigeration	8.12E-05	6.51E-05	5.56E-05	4.76E-05	4.28E-05
space cooling	7.20E-05	5.78E-05	4.94E-05	4.23E-05	3.81E-05
space heating	8.40E-05	6.72E-05	5.74E-05	4.92E-05	4.42E-05
Ventilation	8.14E-05	6.52E-05	5.57E-05	4.77E-05	4.28E-05
water heating	7.88E-05	6.32E-05	5.40E-05	4.62E-05	4.15E-05
Industrial Sector					
all uses	7.63E-05	6.12E-05	5.23E-05	4.48E-05	4.02E-05
Residential Sector					
clothes dryers	7.96E-05	6.38E-05	5.45E-05	4.67E-05	4.19E-05
Cooking	7.83E-05	6.28E-05	5.37E-05	4.60E-05	4.13E-05
Freezers	8.11E-05	6.49E-05	5.55E-05	4.75E-05	4.27E-05
Lighting	8.20E-05	6.57E-05	5.61E-05	4.80E-05	4.32E-05
other uses	7.95E-05	6.37E-05	5.45E-05	4.66E-05	4.19E-05
Refrigeration	8.10E-05	6.49E-05	5.54E-05	4.74E-05	4.26E-05
space cooling	7.26E-05	5.83E-05	4.98E-05	4.27E-05	3.84E-05
space heating	8.35E-05	6.69E-05	5.71E-05	4.89E-05	4.39E-05
water heating	8.02E-05	6.43E-05	5.49E-05	4.70E-05	4.22E-05

Table 13A.4.7 Power Sector Emissions Factors for N_2O (tons/MWh)

	2020	2025	2030	2035	2040
Commercial Sector					
cooking	1.12E-05	8.92E-06	7.59E-06	6.45E-06	5.79E-06
lighting	1.13E-05	8.99E-06	7.64E-06	6.50E-06	5.83E-06
office equipment (non-pc)	1.08E-05	8.62E-06	7.33E-06	6.24E-06	5.60E-06
office equipment (pc)	1.08E-05	8.62E-06	7.33E-06	6.24E-06	5.60E-06
other uses	1.10E-05	8.73E-06	7.43E-06	6.32E-06	5.67E-06
refrigeration	1.17E-05	9.30E-06	7.91E-06	6.73E-06	6.04E-06
space cooling	1.03E-05	8.24E-06	7.00E-06	5.96E-06	5.35E-06
space heating	1.21E-05	9.62E-06	8.18E-06	6.96E-06	6.25E-06
ventilation	1.17E-05	9.32E-06	7.92E-06	6.74E-06	6.05E-06
water heating	1.13E-05	9.02E-06	7.67E-06	6.53E-06	5.86E-06
Industrial Sector					
all uses	1.10E-05	8.73E-06	7.43E-06	6.32E-06	5.67E-06
Residential Sector					
clothes dryers	1.15E-05	9.11E-06	7.75E-06	6.59E-06	5.91E-06
cooking	1.13E-05	8.97E-06	7.63E-06	6.49E-06	5.82E-06
freezers	1.17E-05	9.28E-06	7.89E-06	6.72E-06	6.03E-06
lighting	1.18E-05	9.39E-06	7.99E-06	6.80E-06	6.10E-06
other uses	1.15E-05	9.11E-06	7.74E-06	6.59E-06	5.91E-06
refrigeration	1.17E-05	9.27E-06	7.88E-06	6.71E-06	6.02E-06
space cooling	1.04E-05	8.31E-06	7.06E-06	6.01E-06	5.39E-06
space heating	1.20E-05	9.57E-06	8.14E-06	6.92E-06	6.21E-06
water heating	1.16E-05	9.18E-06	7.81E-06	6.64E-06	5.96E-06

Table 13A.4.8 Electricity Upstream Emissions Factors

	Unit	2020	2025	2030	2035	2040
CO_2	kg/MWh	3.03E+01	3.07E+01	3.08E+01	3.04E+01	3.00E+01
SO_2	g/MWh	5.62E+00	5.45E+00	5.20E+00	5.06E+00	5.00E+00
NOx	g/MWh	3.88E+02	3.95E+02	3.99E+02	3.96E+02	3.91E+02
Hg	g/MWh	1.34E-05	1.26E-05	1.17E-05	1.11E-05	1.08E-05
N_2O	g/MWh	2.75E-01	2.70E-01	2.61E-01	2.53E-01	2.46E-01
CH_4	g/MWh	2.13E+03	2.16E+03	2.20E+03	2.20E+03	2.16E+03

Table 13A.4.9 Natural Gas Upstream Emissions Factors

	Unit	2020	2025	2030	2035	2040
CO_2	kg/ mcf	7.89E+00	7.96E+00	7.90E+00	7.85E+00	7.88E+00
SO_2	g/ mcf	3.44E-02	3.48E-02	3.44E-02	3.41E-02	3.43E-02
NOx	g/ mcf	1.15E+02	1.16E+02	1.15E+02	1.14E+02	1.14E+02
N_2O	g/ mcf	1.26E-02	1.28E-02	1.27E-02	1.26E-02	1.26E-02
CH_4	g/ mcf	6.86E+02	6.89E+02	6.86E+02	6.86E+02	6.87E+02

Table 13A.4.10 Fuel Oil Upstream Emissions Factors

	Unit	2020	2025	2030	2035	2040
CO_2	kg/bbl	7.00E+01	6.91E+01	6.78E+01	6.77E+01	6.75E+01
SO_2	g/bbl	1.54E+01	1.53E+01	1.50E+01	1.49E+01	1.48E+01
NOx	g/bbl	8.14E+02	8.10E+02	7.91E+02	7.87E+02	7.81E+02
Hg	g/bbl	6.93E-06	6.47E-06	6.22E-06	6.21E-06	6.09E-06
N_2O	g/bbl	6.30E-01	6.25E-01	6.11E-01	6.08E-01	6.03E-01
CH_4	g/bbl	8.82E+02	8.72E+02	8.57E+02	8.55E+02	8.54E+02

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CHAPTER 14. MONETIZATION OF EMISSIONS REDUCTION BENEFITS

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CHAPTER 14. MONETIZATION OF EMISSIONS REDUCTION BENEFITS

14.1 INTRODUCTION

As part of its assessment of energy conservation standards for residential boilers, the U.S. Department of Energy (DOE) estimated the monetary benefits likely to result from the reduced emissions of carbon dioxide (CO_2) and nitrogen oxides (NO_X) that are expected to result from each trial standard level (TSL) considered for this rulemaking. This chapter summarizes the basis for the monetary values used for each of these emissions and presents the modeled benefits from the estimated reductions.

14.2 MONETIZING CARBON DIOXIDE EMISSIONS

14.2.1 Social Cost of Carbon

The social cost of carbon (SCC) is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services. Estimates of the SCC are provided in dollars per metric ton of carbon dioxide. A domestic SCC value is meant to reflect the value of damages in the United States resulting from a unit change in carbon dioxide emissions, while a global SCC value is meant to reflect the value of damages worldwide.

Under section 1(b) of Executive Order 12866, agencies must, to the extent permitted by law, "assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs." The purpose of the SCC estimates presented here is to allow agencies to incorporate the monetized social benefits of reducing CO_2 emissions into cost-benefit analyses of regulatory actions that have small, or "marginal," impacts on cumulative global emissions. The estimates are presented with an acknowledgement of the many uncertainties involved and with a clear understanding that they should be updated over time to reflect increasing knowledge of the science and economics of climate impacts.

As part of the interagency process that developed these SCC estimates, technical experts from numerous agencies met on a regular basis to explore the technical literature in relevant fields, discuss key model inputs and assumptions, and consider public comments. The main objective of this process was to develop a range of SCC values using a defensible set of input assumptions grounded in the existing scientific and economic literatures. In this way, key uncertainties and model differences transparently and consistently inform the range of SCC estimates used in the rulemaking process.

14.2.2 Monetizing Carbon Dioxide Emissions

When attempting to assess the incremental economic impacts of carbon dioxide emissions, the analyst faces a number of serious challenges. A report from the National Research

Council[1] points out that any assessment will suffer from uncertainty, speculation, and lack of information about (1) future emissions of greenhouse gases, (2) the effects of past and future emissions on the climate system, (3) the impact of changes in climate on the physical and biological environment, and (4) the translation of these environmental impacts into economic damages. As a result, any effort to quantify and monetize the harms associated with climate change will raise serious questions of science, economics, and ethics and should be viewed as provisional.

Despite the serious limits of both quantification and monetization, SCC estimates can be useful in estimating the social benefits of reducing carbon dioxide emissions. Most Federal regulatory actions can be expected to have marginal impacts on global emissions. For such policies, the agency can estimate the benefits from reduced (or costs from increased) emissions in any future year by multiplying the change in emissions in that year by the SCC value appropriate for that year. The net present value of the benefits can then be calculated by multiplying each of these future benefits by an appropriate discount factor and summing across all affected years. This approach assumes that the marginal damages from increased emissions are constant for small departures from the baseline emissions path, an approximation that is reasonable for policies that have effects on emissions that are small relative to cumulative global carbon dioxide emissions.

In 2009, an interagency process was initiated to offer a preliminary assessment of how best to quantify the benefits from reducing carbon dioxide emissions. To ensure consistency in how benefits are evaluated across agencies, the Administration sought to develop a transparent and defensible method, specifically designed for the rulemaking process, to quantify avoided climate change damages from reduced CO_2 emissions. The interagency group did not undertake any original analysis. Instead, it combined SCC estimates from the existing literature to use as interim values until a more comprehensive analysis could be conducted. The outcome of the preliminary assessment by the interagency group was a set of five interim values: global SCC estimates for 2007 (in 2006 dollars) of \$55, \$33, \$19, \$10, and \$5 per ton of CO_2.[2] These interim values represented the first sustained interagency effort within the U.S. government to develop an SCC for use in regulatory analysis. The results of this preliminary effort were presented in several proposed and final rules.

14.2.3 Current Approach and Key Assumptions

After the release of the interim values, the interagency group reconvened on a regular basis to generate improved SCC estimates, which were considered for this proposed rule. Specifically, the group considered public comments and further explored the technical literature in relevant fields. The interagency group relied on three integrated assessment models (IAMs) commonly used to estimate the SCC: the FUND, DICE, and PAGE models.[a] These models are frequently cited in the peer-reviewed literature and were used in the last assessment of the Intergovernmental Panel on Climate Change. Each model was given equal weight in the SCC values that were developed.

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[a] The models are described in appendix 14A of the TSD.

Each model takes a slightly different approach to model how changes in emissions result in changes in economic damages. A key objective of the interagency process was to enable a consistent exploration of the three models while respecting the different approaches to quantifying damages taken by the key modelers in the field. An extensive review of the literature was conducted to select three sets of input parameters for these models: (1) climate sensitivity; (2) socio-economic and emissions trajectories; and (3) discount rates. A probability distribution for climate sensitivity was specified as an input into all three models. In addition, the interagency group used a range of scenarios for the socio-economic parameters and a range of values for the discount rate. All other model features were left unchanged, relying on the model developers' best estimates and judgments.

The interagency group selected four SCC values for use in regulatory analyses.[2] (The 2010 report is reproduced in appendix 14A.) Three values are based on the average SCC from three integrated assessment models, at discount rates of 2.5, 3, and 5 percent. The fourth value, which represents the 95th percentile SCC estimate across all three models at a 3 percent discount rate, is included to represent higher-than-expected impacts from temperature change further out in the tails of the SCC distribution. The values grow in real terms over time, as depicted in Table 14.2.1. Additionally, the interagency group determined that a range of values from 7 percent to 23 percent should be used to adjust the global SCC to calculate domestic effects,[b] although preference is given to consideration of the global benefits of reducing CO_2 emissions.

The SCC values used for this analysis were generated using the most recent versions of the three integrated assessment models that have been published in the peer-reviewed literature, as described in the 2013 update from the interagency working group (revised July 2015).[3] Table 14.2.2 shows the updated sets of SCC estimates in five year increments from 2010 to 2050. Appendix 14-B provides the full set of SCC estimates, as well as the 2013 report from the interagency group. The central value that emerges is the average SCC across models at the 3 percent discount rate. However, for purposes of capturing the uncertainties involved in regulatory impact analysis, the interagency group emphasizes the importance of including all four sets of SCC values.

[b] It is recognized that this calculation for domestic values is approximate, provisional, and highly speculative. There is no a priori reason why domestic benefits should be a constant fraction of net global damages over time.

Table 14.2.1 Annual SCC Values from 2010 Interagency Report, 2010 – 2050 (in 2007 dollars per metric ton)

Year	Discount Rate %			
	5	3	2.5	3
	Average	Average	Average	95th Percentile
2010	4.7	21.4	35.1	64.9
2015	5.7	23.8	38.4	72.8
2020	6.8	26.3	41.7	80.7
2025	8.2	29.6	45.9	90.4
2030	9.7	32.8	50.0	100.0
2035	11.2	36.0	54.2	109.7
2040	12.7	39.2	58.4	119.3
2045	14.2	42.1	61.7	127.8
2050	15.7	44.9	65.0	136.2

Table 14.2.2 Annual SCC Values from 2013 Interagency Update (Revised July 2015), 2010–2050 (in 2007 dollars per metric ton CO_2)

Year	Discount Rate %			
	5	3	2.5	3
	Average	Average	Average	95th Percentile
2010	10	31	50	86
2015	11	36	56	105
2020	12	42	62	123
2025	14	46	68	138
2030	16	50	73	152
2035	18	55	78	168
2040	21	60	84	183
2045	23	64	89	197
2050	26	69	95	212

It is important to recognize that a number of key uncertainties remain, and that current SCC estimates should be treated as provisional and revisable since they will evolve with improved scientific and economic understanding. The interagency group also recognizes that the existing models are imperfect and incomplete. The National Research Council report mentioned above points out that there is tension between the goal of producing quantified estimates of the economic damages from an incremental ton of carbon and the limits of existing efforts to model these effects. There are a number of concerns and problems that should be addressed by the research community, including research programs housed in many of the agencies participating in the interagency process to estimate the SCC. The interagency group intends to periodically review and reconsider estimates of the SCC used for cost-benefit analyses to reflect increasing knowledge of the science and economics of climate impacts, as well as improvements in modeling.

In summary, in considering the potential global benefits resulting from reduced CO_2 emissions, DOE used the values from the 2013 interagency report (revised July 2015), escalated to 2014$ using the implicit price deflator for gross domestic product (GDP) from the Bureau of Economic Analysis. For each of the four cases specified, the values used for emissions in 2015 were $12.2, $40.0, $62.3, and $117 per metric ton avoided. DOE derived values after 2050 using the relevant growth rates for the 2040-2050 period in the interagency update.

DOE multiplied the CO_2 emissions reduction estimated for each year by the SCC value for that year in each of the four cases. To calculate a present value of the stream of monetary values, DOE discounted the values in each of the four cases using the specific discount rate that had been used to obtain the SCC values in each case.

14.3 VALUATION OF OTHER EMISSIONS REDUCTIONS

As noted in chapter 13, new or amended energy conservation standards would reduce NO_X emissions in those 22 States that are not affected by caps. DOE considered the potential monetary benefit of reduced NO_X emissions from the TSLs it considered. DOE estimated the monetized value of NO_X emissions reductions using benefit per ton estimates from the *Regulatory Impact Analysis for the Proposed Carbon Pollution Guidelines for Existing Power Plants and Emission Standards for Modified and Reconstructed Power Plants,* published in June 2014 by EPA's Office of Air Quality Planning and Standards.[c] The report includes low and high values for 2020, 2025, and 2030 that use discount rates of 3 percent and 7 percent (see Tables 4-7, 4-8, and 4-9 in the report). See Table 14.3.1. DOE assigned values for 2021-2024 and 2026-2029 using, respectively, the values for 2020 and 2025. DOE assigned values after 2030 using the value for 2030. To be conservative, DOE's primary estimates presented in this chapter utilize the low benefit per ton estimates.

Table 14.3.1 National Benefit per Ton for Emissions from Electricity Generating Units (2011$)

Year of Emission	NO_X (as $PM_{2.5}$)	
	3% discount rate	*7% discount rate*
2020	5,600 to 13,000	5,000 to 11,000
2025	6,000 to 14,000	5,400 to 12,000
2030	6,400 to 14,000	5,800 to 13,000

[c] http://www3.epa.gov/ttnecas1/regdata/RIAs/111dproposalRIAfinal0602.pdf. Note that DOE is primarily using a national benefit-per-ton estimate for particulate matter emitted from the Electric Generating Unit sector based on an estimate of premature mortality derived from the ACS study (Krewski et al., 2009).[4] If the benefit-per-ton estimates were based on the Six Cities study (Lepuele et al., 2012),[5] the values would be nearly two-and-a-half times larger. Because of the sensitivity of the benefit-per-ton estimate to the geographical considerations of sources and receptors of emissions, DOE intends to investigate refinements to the agency's current approach of one national estimate by assessing the regional approach taken by EPA's Regulatory Impact Analysis for the Clean Power Plan Final Rule.

To calculate present value of the total monetary sum from reduced NO_X emissions, DOE applied discount rates of 3 percent and 7 percent to the appropriate $/ton series.

DOE is evaluating appropriate values to use to monetize avoided SO_2 and Hg emissions. The interagency group is investigating appropriate values to use to monetize avoided CH_4 emissions. DOE did not monetize these emissions for the current analysis.

14.4 RESULTS

Table 14.4.1 presents the global values of CO_2 emissions reductions for each considered AFUE TSLs. DOE calculated domestic values as a range from 7 percent to 23 percent of the global values, and these results are presented in Table 14.4.2. Table 14.4.3 and Table 14.4.4 present global and domestic values for boilers standby and of mode standards.

Table 14.4.5 reports the present value of cumulative NOx emissions reductions for each AFUE TSL, calculated from NOx values discounted at seven and three percent discount rates. Table 14.4.6 presents similar results for standby and off mode TSLs.

Table 14.4.1 Estimates of Global Present Value of CO_2 Emissions Reduction for AFUE Standards

TSL	SCC Case*			
	5% discount rate, average*	3% discount rate, average*	2.5% discount rate, average*	3% discount rate, 95th percentile*
	Million 2014$			
Power Sector and Site Emissions				
1	19.1	95.1	154	290
2	31.5	156	253	477
3	46.2	229	371	700
4	198	1018	1659	3113
5	399	2041	3325	6235
Upstream Emissions				
1	2.82	14.0	22.7	42.7
2	4.68	23.2	37.5	70.8
3	6.78	33.6	54.4	103
4	32.2	165	268	503
5	60.5	309	503	944
Total Emissions				
1	22.0	109	176	333
2	36.2	179	290	548
3	53.0	263	425	802
4	230	1183	1927	3616
5	459	2350	3828	7180

* For each of the four cases, the corresponding SCC value for emissions in 2015 is $12.2, $40.0, $62.3, and $117 per metric ton (2014$).

Table 14.4.2 Estimates of Domestic Present Value of CO_2 Emissions Reduction for AFUE Standards

TSL	SCC Case*			
	5% discount rate, average*	3% discount rate, average*	2.5% discount rate, average*	3% discount rate, 95th percentile*
	Million 2014$			
Power Sector and Site Emissions				
1	1.3 to 4.4	6.7 to 21.9	10.8 to 35.4	20.3 to 66.7
2	2.2 to 7.3	10.9 to 35.9	17.7 to 58.1	33.4 to 109.7
3	3.2 to 10.6	16.0 to 52.7	26.0 to 85.3	49.0 to 160.9
4	13.9 to 45.6	71.3 to 234.2	116.1 to 381.6	217.9 to 715.9
5	27.9 to 91.7	142.9 to 469.5	232.7 to 764.7	436.5 to 1434.1
Upstream Emissions				
1	0.2 to 0.6	1.0 to 3.2	1.6 to 5.2	3.0 to 9.8
2	0.3 to 1.1	1.6 to 5.3	2.6 to 8.6	5.0 to 16.3
3	0.5 to 1.6	2.4 to 7.7	3.8 to 12.5	7.2 to 23.6
4	2.3 to 7.4	11.5 to 37.9	18.8 to 61.6	35.2 to 115.7
5	4.2 to 13.9	21.6 to 71.1	35.2 to 115.8	66.1 to 217.2
Total Emissions				
1	1.5 to 5.1	7.6 to 25.1	12.4 to 40.6	23.3 to 76.6
2	2.5 to 8.3	12.6 to 41.3	20.3 to 66.8	38.3 to 126.0
3	3.7 to 12.2	18.4 to 60.5	29.8 to 97.8	56.2 to 184.5
4	16.1 to 53.0	82.8 to 272.1	134.9 to 443.2	253.1 to 831.6
5	32.1 to 105.6	164.5 to 540.6	268.0 to 880.4	502.6 to 1651.3

* For each of the four cases, the corresponding SCC value for emissions in 2015 is $12.2, $40.0, $62.3, and $117 per metric ton (2014$).

Table 14.4.3 Estimates of Global Present Value of CO_2 Emissions Reduction for Standby and Off Mode Standards

TSL	SCC Case*			
	5% discount rate, average*	3% discount rate, average*	2.5% discount rate, average*	3% discount rate, 95th percentile*
	Million 2014$			
Power Sector and Site Emissions				
1	0.287	1.43	2.32	4.37
2	0.401	2.01	3.25	6.12
3	0.803	4.01	6.50	12.2
Upstream Emissions				
1	0.016	0.081	0.132	0.249
2	0.023	0.114	0.185	0.348
3	0.045	0.228	0.370	0.696
Total Emissions				
1	0.303	1.51	2.46	4.62
2	0.424	2.12	3.44	6.47
3	0.848	4.24	6.87	12.9

* For each of the four cases, the corresponding SCC value for emissions in 2015 is $12.2, $40.0, $62.3, and $117 per metric ton (2014$).

Table 14.4.4 Estimates of Domestic Present Value of CO_2 Emissions Reduction for Standby and Off Mode Standards

TSL	SCC Case*			
	5% discount rate, average*	**3% discount rate, average***	**2.5% discount rate, average***	**3% discount rate, 95th percentile***
	Million 2014$			
Power Sector and Site Emissions				
1	0.0 to 0.1	0.1 to 0.3	0.2 to 0.5	0.3 to 1.0
2	0.0 to 0.1	0.1 to 0.5	0.2 to 0.7	0.4 to 1.4
3	0.1 to 0.2	0.3 to 0.9	0.5 to 1.5	0.9 to 2.8
Upstream Emissions				
1	0.0 to 0.0	0.0 to 0.0	0.0 to 0.0	0.0 to 0.1
2	0.0 to 0.0	0.0 to 0.0	0.0 to 0.0	0.0 to 0.1
3	0.0 to 0.0	0.0 to 0.1	0.0 to 0.1	0.0 to 0.2
Total Emissions				
1	0.0 to 0.1	0.1 to 0.3	0.2 to 0.6	0.3 to 1.1
2	0.0 to 0.1	0.1 to 0.5	0.2 to 0.8	0.5 to 1.5
3	0.1 to 0.2	0.3 to 1.0	0.5 to 1.6	0.9 to 3.0

* For each of the four cases, the corresponding SCC value for emissions in 2015 is $12.2, $40.0, $62.3, and $117 per metric ton (2014$).

Table 14.4.5 Estimates of Present Value of NO_X Emissions Reduction for AFUE Standards

TSL	3% discount rate	7% discount rate
	Million 2014$	
Power Sector and Site Emissions		
1	101	33.3
2	264	87.6
3	282	93.8
4	801	184
5	932	224
Upstream Emissions		
1	19.5	6.5
2	30.6	10.2
3	46.1	15.4
4	228	67.5
5	437	131
Total Emissions		
1	121	39.8
2	294	97.8
3	328	109
4	1029	251
5	1369	354

Table 14.4.6 Estimates of Present Value of NO_X Emissions Reduction for Standby and Off Mode Standards

TSL	3% discount rate	7% discount rate
	Million 2014$	
Power Sector and Site Emissions		
1	0.147	0.048
2	0.206	0.067
3	0.411	0.134
Upstream Emissions		
1	0.108	0.034
2	0.151	0.048
3	0.302	0.096
Total Emissions		
1	0.255	0.082
2	0.357	0.115
3	0.713	0.231

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APPENDIX 14A. SOCIAL COST OF CARBON FOR REGULATORY IMPACT ANALYSIS UNDER EXECUTIVE ORDER 12866

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APPENDIX 14A. SOCIAL COST OF CARBON FOR REGULATORY IMPACT ANALYSIS UNDER EXECUTIVE ORDER 12866[a]

14A.1 EXECUTIVE SUMMARY

Under Executive Order 12866, agencies are required, to the extent permitted by law, "to assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs." The purpose of the "social cost of carbon" (SCC) estimates presented here is to allow agencies to incorporate the social benefits of reducing carbon dioxide (CO_2) emissions into cost-benefit analyses of regulatory actions that have small, or "marginal," impacts on cumulative global emissions. The estimates are presented with an acknowledgement of the many uncertainties involved and with a clear understanding that they should be updated over time to reflect increasing knowledge of the science and economics of climate impacts.

The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change.

This document presents a summary of the interagency process that developed these SCC estimates. Technical experts from numerous agencies met on a regular basis to consider public comments, explore the technical literature in relevant fields, and discuss key model inputs and assumptions. The main objective of this process was to develop a range of SCC values using a defensible set of input assumptions grounded in the existing scientific and economic literatures. In this way, key uncertainties and model differences transparently and consistently inform the range of SCC estimates used in the rulemaking process.

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[a] Prepared by Interagency Working Group on Social Cost of Carbon, United States Government.
With participation by:
Council of Economic Advisers
Council on Environmental Quality
Department of Agriculture
Department of Commerce
Department of Energy
Department of Transportation
Environmental Protection Agency
National Economic Council
Office of Energy and Climate Change
Office of Management and Budget
Office of Science and Technology Policy
Department of the Treasury

The interagency group selected four SCC values for use in regulatory analyses. Three values are based on the average SCC from three integrated assessment models, at discount rates of 2.5, 3, and 5 percent. The fourth value, which represents the 95th percentile SCC estimate across all three models at a 3 percent discount rate, is included to represent higher-than-expected impacts from temperature change further out in the tails of the SCC distribution.

Table 14A.1.1 Social Cost of CO_2, 2010 – 2050 (in 2007 dollars)

	Discount Rate			
	5%	3%	2.5%	3%
Year	Avg	Avg	Avg	95th
2010	4.7	21.4	35.1	64.9
2015	5.7	23.8	38.4	72.8
2020	6.8	26.3	41.7	80.7
2025	8.2	29.6	45.9	90.4
2030	9.7	32.8	50.0	100.0
2035	11.2	36.0	54.2	109.7
2040	12.7	39.2	58.4	119.3
2045	14.2	42.1	61.7	127.8
2050	15.7	44.9	65.0	136.2

14A.2 MONETIZING CARBON DIOXIDE EMISSIONS

The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year. We report estimates of the SCC in dollars per metric ton of carbon dioxide throughout this document.[b]

When attempting to assess the incremental economic impacts of carbon dioxide emissions, the analyst faces a number of serious challenges. A recent report from the National Academies of Science (NRC 2009) points out that any assessment will suffer from uncertainty, speculation, and lack of information about (1) future emissions of greenhouse gases, (2) the effects of past and future emissions on the climate system, (3) the impact of changes in climate on the physical and biological environment, and (4) the translation of these environmental impacts into economic damages. As a result, any effort to quantify and monetize the harms associated with climate change will raise serious questions of science, economics, and ethics and should be viewed as provisional.

[b] In this document, we present all values of the SCC as the cost per metric ton of CO_2 emissions. Alternatively, one could report the SCC as the cost per metric ton of carbon emissions. The multiplier for translating between mass of CO_2 and the mass of carbon is 3.67 (the molecular weight of CO_2 divided by the molecular weight of carbon = 44/12 = 3.67).

Despite the serious limits of both quantification and monetization, SCC estimates can be useful in estimating the social benefits of reducing carbon dioxide emissions. Under Executive Order 12866, agencies are required, to the extent permitted by law, "to assess both the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs." The purpose of the SCC estimates presented here is to make it possible for agencies to incorporate the social benefits from reducing carbon dioxide emissions into cost-benefit analyses of regulatory actions that have small, or "marginal," impacts on cumulative global emissions. Most federal regulatory actions can be expected to have marginal impacts on global emissions.

For such policies, the benefits from reduced (or costs from increased) emissions in any future year can be estimated by multiplying the change in emissions in that year by the SCC value appropriate for that year. The net present value of the benefits can then be calculated by multiplying each of these future benefits by an appropriate discount factor and summing across all affected years. This approach assumes that the marginal damages from increased emissions are constant for small departures from the baseline emissions path, an approximation that is reasonable for policies that have effects on emissions that are small relative to cumulative global carbon dioxide emissions. For policies that have a large (non-marginal) impact on global cumulative emissions, there is a separate question of whether the SCC is an appropriate tool for calculating the benefits of reduced emissions; we do not attempt to answer that question here.

An interagency group convened on a regular basis to consider public comments, explore the technical literature in relevant fields, and discuss key inputs and assumptions in order to generate SCC estimates. Agencies that actively participated in the interagency process include the Environmental Protection Agency, and the Departments of Agriculture, Commerce, Energy, Transportation, and Treasury. This process was convened by the Council of Economic Advisers and the Office of Management and Budget, with active participation and regular input from the Council on Environmental Quality, National Economic Council, Office of Energy and Climate Change, and Office of Science and Technology Policy. The main objective of this process was to develop a range of SCC values using a defensible set of input assumptions that are grounded in the existing literature. In this way, key uncertainties and model differences can more transparently and consistently inform the range of SCC estimates used in the rulemaking process.

The interagency group selected four SCC estimates for use in regulatory analyses. For 2010, these estimates are $5, $21, $35, and $65 (in 2007 dollars). The first three estimates are based on the average SCC across models and socioeconomic and emissions scenarios at the 5, 3, and 2.5 percent discount rates, respectively. The fourth value is included to represent the higher-than-expected impacts from temperature change further out in the tails of the SCC distribution. For this purpose, we use the SCC value for the 95th percentile at a 3 percent discount rate. The central value is the average SCC across models at the 3 percent discount rate. For purposes of capturing the uncertainties involved in regulatory impact analysis, we emphasize the importance and value of considering the full range. These SCC estimates also grow over time. For instance,

the central value increases to \$24 per ton of CO_2 in 2015 and \$26 per ton of CO_2 in 2020. See section 14A.5 for the full range of annual SCC estimates from 2010 to 2050.

It is important to emphasize that the interagency process is committed to updating these estimates as the science and economic understanding of climate change and its impacts on society improves over time. Specifically, we have set a preliminary goal of revisiting the SCC values within two years or at such time as substantially updated models become available, and to continue to support research in this area. In the meantime, we will continue to explore the issues raised in this document and consider public comments as part of the ongoing interagency process.

14A.3 SOCIAL COST OF CARBON VALUES USED IN PAST REGULATORY ANALYSES

To date, economic analyses for Federal regulations have used a wide range of values to estimate the benefits associated with reducing carbon dioxide emissions. In the final model year 2011 CAFE rule, the Department of Transportation (DOT) used both a "domestic" SCC value of \$2 per ton of CO_2 and a "global" SCC value of \$33 per ton of CO_2 for 2007 emission reductions (in 2007 dollars), increasing both values at 2.4 percent per year. It also included a sensitivity analysis at \$80 per ton of CO_2. A domestic SCC value is meant to reflect the value of damages in the United States resulting from a unit change in carbon dioxide emissions, while a global SCC value is meant to reflect the value of damages worldwide.

A 2008 regulation proposed by DOT assumed a domestic SCC value of \$7 per ton CO_2 (in 2006 dollars) for 2011 emission reductions (with a range of \$0-\$14 for sensitivity analysis), also increasing at 2.4 percent per year. A regulation finalized by DOE in October of 2008 used a domestic SCC range of \$0 to \$20 per ton CO_2 for 2007 emission reductions (in 2007 dollars). In addition, EPA's 2008 Advance Notice of Proposed Rulemaking for Greenhouse Gases identified what it described as "very preliminary" SCC estimates subject to revision. EPA's global mean values were \$68 and \$40 per ton CO_2 for discount rates of approximately 2 percent and 3 percent, respectively (in 2006 dollars for 2007 emissions).

In 2009, an interagency process was initiated to offer a preliminary assessment of how best to quantify the benefits from reducing carbon dioxide emissions. To ensure consistency in how benefits are evaluated across agencies, the Administration sought to develop a transparent and defensible method, specifically designed for the rulemaking process, to quantify avoided climate change damages from reduced CO_2 emissions. The interagency group did not undertake any original analysis. Instead, it combined SCC estimates from the existing literature to use as interim values until a more comprehensive analysis could be conducted.

The outcome of the preliminary assessment by the interagency group was a set of five interim values: global SCC estimates for 2007 (in 2006 dollars) of \$55, \$33, \$19, \$10, and \$5 per ton of CO_2. The \$33 and \$5 values represented model-weighted means of the published estimates produced from the most recently available versions of three integrated assessment models—

DICE, PAGE, and FUND—at approximately 3 and 5 percent discount rates. The $55 and $10 values were derived by adjusting the published estimates for uncertainty in the discount rate (using factors developed by Newell and Pizer (2003)) at 3 and 5 percent discount rates, respectively. The $19 value was chosen as a central value between the $5 and $33 per ton estimates. All of these values were assumed to increase at 3 percent annually to represent growth in incremental damages over time as the magnitude of climate change increases.

These interim values represent the first sustained interagency effort within the U.S. government to develop an SCC for use in regulatory analysis. The results of this preliminary effort were presented in several proposed and final rules and were offered for public comment in connection with proposed rules, including the joint EPA-DOT fuel economy and CO_2 tailpipe emission proposed rules.

14A.4 APPROACH AND KEY ASSUMPTIONS

Since the release of the interim values, the interagency group has reconvened on a regular basis to generate improved SCC estimates. Specifically, the group has considered public comments and further explored the technical literature in relevant fields. This section details the several choices and assumptions that underlie the resulting estimates of the SCC.

It is important to recognize that a number of key uncertainties remain, and that current SCC estimates should be treated as provisional and revisable, since they will evolve with improved scientific and economic understanding. The interagency group also recognizes that the existing models are imperfect and incomplete. The National Academy of Science (2009) points out that there is tension between the goal of producing quantified estimates of the economic damages from an incremental ton of carbon and the limits of existing efforts to model these effects. Throughout this document, we highlight a number of concerns and problems that should be addressed by the research community, including research programs housed in many of the agencies participating in the interagency process to estimate the SCC.

The U.S. Government will periodically review and reconsider estimates of the SCC used for cost-benefit analyses to reflect increasing knowledge of the science and economics of climate impacts, as well as improvements in modeling. In this context, statements recognizing the limitations of the analysis and calling for further research take on exceptional significance. The interagency group offers the new SCC values with all due humility about the uncertainties embedded in them and with a sincere promise to continue work to improve them.

14A.4.1 Integrated Assessment Models

We rely on three integrated assessment models (IAMs) commonly used to estimate the SCC: the FUND, DICE, and PAGE models.[c] These models are frequently cited in the peer-reviewed literature and used in the IPCC assessment. Each model is given equal weight in the SCC values developed through this process, bearing in mind their different limitations (discussed below).

These models are useful because they combine climate processes, economic growth, and feedbacks between the climate and the global economy into a single modeling framework. At the same time, they gain this advantage at the expense of a more detailed representation of the underlying climatic and economic systems. DICE, PAGE, and FUND all take stylized, reduced-form approaches (see NRC 2009 for a more detailed discussion; see Nordhaus 2008 on the possible advantages of this approach). Other IAMs may better reflect the complexity of the science in their modeling frameworks but do not link physical impacts to economic damages. There is currently a limited amount of research linking climate impacts to economic damages, which makes this exercise even more difficult. Underlying the three IAMs selected for this exercise are a number of simplifying assumptions and judgments reflecting the various modelers' best attempts to synthesize the available scientific and economic research characterizing these relationships.

The three IAMs translate emissions into changes in atmospheric greenhouse concentrations, atmospheric concentrations into changes in temperature, and changes in temperature into economic damages. The emissions projections used in the models are based on specified socioeconomic (GDP and population) pathways. These emissions are translated into concentrations using the carbon cycle built into each model, and concentrations are translated into warming based on each model's simplified representation of the climate and a key parameter, climate sensitivity. Each model uses a different approach to translate warming into damages. Finally, transforming the stream of economic damages over time into a single value requires judgments about how to discount them.

Each model takes a slightly different approach to model how changes in emissions result in changes in economic damages. In PAGE, for example, the consumption-equivalent damages in each period are calculated as a fraction of GDP, depending on the temperature in that period relative to the pre-industrial average temperature in each region. In FUND, damages in each period also depend on the rate of temperature change from the prior period. In DICE, temperature affects both consumption and investment. We describe each model in greater detail here. In section 14A.7, we discuss key gaps in how the models account for various scientific and

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[c] The DICE (Dynamic Integrated Climate and Economy) model by William Nordhaus evolved from a series of energy models and was first presented in 1990 (Nordhaus and Boyer 2000, Nordhaus 2008). The PAGE (Policy Analysis of the Greenhouse Effect) model was developed by Chris Hope in 1991 for use by European decision-makers in assessing the marginal impact of carbon emissions (Hope 2006, Hope 2008). The FUND (Climate Framework for Uncertainty, Negotiation, and Distribution) model, developed by Richard Tol in the early 1990s originally to study international capital transfers in climate policy, is now widely used to study climate impacts (*e.g.*, Tol 2002a, Tol 2002b, Anthoff *et al*. 2009, Tol 2009).

economic processes (*e.g.*, the probability of catastrophe, and the ability to adapt to climate change and the physical changes it causes).

The parameters and assumptions embedded in the three models vary widely. A key objective of the interagency process was to enable a consistent exploration of the three models while respecting the different approaches to quantifying damages taken by the key modelers in the field. An extensive review of the literature was conducted to select three sets of input parameters for these models: climate sensitivity, socioeconomic and emissions trajectories, and discount rates. A probability distribution for climate sensitivity was specified as an input into all three models. In addition, the interagency group used a range of scenarios for the socioeconomic parameters and a range of values for the discount rate. All other model features were left unchanged, relying on the model developers' best estimates and judgments. In DICE, these parameters are handled deterministically and represented by fixed constants; in PAGE, most parameters are represented by probability distributions. FUND was also run in a mode in which parameters were treated probabilistically.

The sensitivity of the results to other aspects of the models (*e.g.*, the carbon cycle or damage function) is also important to explore in the context of future revisions to the SCC but has not been incorporated into these estimates. Areas for future research are highlighted at the end of this document.

The DICE Model

The DICE model is an optimal growth model based on a global production function with an extra stock variable (atmospheric carbon dioxide concentrations). Emission reductions are treated as analogous to investment in "natural capital." By investing in natural capital today through reductions in emissions—implying reduced consumption—harmful effects of climate change can be avoided and future consumption thereby increased.

For purposes of estimating the SCC, carbon dioxide emissions are a function of global GDP and the carbon intensity of economic output, with the latter declining over time due to technological progress. The DICE damage function links global average temperature to the overall impact on the world economy. It varies quadratically with temperature change to capture the more rapid increase in damages expected to occur under more extreme climate change, and is calibrated to include the effects of warming on the production of market and nonmarket goods and services. It incorporates impacts on agriculture, coastal areas (due to sea level rise), "other vulnerable market sectors" (based primarily on changes in energy use), human health (based on climate-related diseases, such as malaria and dengue fever, and pollution), non-market amenities (based on outdoor recreation), and human settlements and ecosystems. The DICE damage function also includes the expected value of damages associated with low probability, high impact "catastrophic" climate change. This last component is calibrated based on a survey of experts (Nordhaus 1994). The expected value of these impacts is then added to the other market and non-market impacts mentioned above.

No structural components of the DICE model represent adaptation explicitly, though it is included implicitly through the choice of studies used to calibrate the aggregate damage function. For example, its agricultural impact estimates assume that farmers can adjust land use decisions in response to changing climate conditions, and its health impact estimates assume improvements in healthcare over time. In addition, the small impacts on forestry, water systems, construction, fisheries, and outdoor recreation imply optimistic and costless adaptation in these sectors (Nordhaus and Boyer, 2000; Warren *et al*., 2006). Costs of resettlement due to sea level rise are incorporated into damage estimates, but their magnitude is not clearly reported. Mastrandrea's (2009) review concludes that "in general, DICE assumes very effective adaptation, and largely ignores adaptation costs."

Note that the damage function in DICE has a somewhat different meaning from the damage functions in FUND and PAGE. Because GDP is endogenous in DICE and because damages in a given year reduce investment in that year, damages propagate forward in time and reduce GDP in future years. In contrast, GDP is exogenous in FUND and PAGE, so damages in any given year do not propagate forward.[d]

The PAGE Model

PAGE2002 (version 1.4epm) treats GDP growth as exogenous. It divides impacts into economic, non-economic, and catastrophic categories and calculates these impacts separately for eight geographic regions. Damages in each region are expressed as a fraction of output, where the fraction lost depends on the temperature change in each region. Damages are expressed as power functions of temperature change. The exponents of the damage function are the same in all regions but are treated as uncertain, with values ranging from 1 to 3 (instead of being fixed at 2 as in DICE).

PAGE2002 includes the consequences of catastrophic events in a separate damage sub-function. Unlike DICE, PAGE2002 models these events probabilistically. The probability of a "discontinuity" (*i.e.*, a catastrophic event) is assumed to increase with temperature above a specified threshold. The threshold temperature, the rate at which the probability of experiencing a discontinuity increases above the threshold, and the magnitude of the resulting catastrophe are all modeled probabilistically.

Adaptation is explicitly included in PAGE. Impacts are assumed to occur for temperature increases above some tolerable level (2°C for developed countries and 0°C for developing countries for economic impacts, and 0°C for all regions for non-economic impacts), but

[d] Using the default assumptions in DICE 2007, this effect generates an approximately 25 percent increase in the SCC relative to damages calculated by fixing GDP. In DICE2007, the time path of GDP is endogenous. Specifically, the path of GDP depends on the rate of saving and level of abatement in each period chosen by the optimizing representative agent in the model. We made two modifications to DICE to make it consistent with EMF GDP trajectories (see next section): we assumed a fixed rate of savings of 20 percent, and we re-calibrated the exogenous path of total factor productivity so that DICE would produce GDP projections in the absence of warming that exactly matched the EMF scenarios.

adaptation is assumed to reduce these impacts. Default values in PAGE2002 assume that the developed countries can ultimately eliminate up to 90 percent of all economic impacts beyond the tolerable 2°C increase and that developing countries can eventually eliminate 50 percent of their economic impacts. All regions are assumed to be able to mitigate 25 percent of the non-economic impacts through adaptation (Hope 2006).

The FUND Model

Like PAGE, the FUND model treats GDP growth as exogenous. It includes separately calibrated damage functions for eight market and nonmarket sectors: agriculture, forestry, water, energy (based on heating and cooling demand), sea level rise (based on the value of land lost and the cost of protection), ecosystems, human health (diarrhea, vector-borne diseases, and cardiovascular and respiratory mortality), and extreme weather. Each impact sector has a different functional form, and is calculated separately for sixteen geographic regions. In some impact sectors, the fraction of output lost or gained due to climate change depends not only on the absolute temperature change but also on the rate of temperature change and level of regional income.[e] In the forestry and agricultural sectors, economic damages also depend on CO_2 concentrations.

Tol (2009) discusses impacts not included in FUND, noting that many are likely to have a relatively small effect on damage estimates (both positive and negative). However, he characterizes several omitted impacts as "big unknowns": for instance, extreme climate scenarios, biodiversity loss, and effects on economic development and political violence. With regard to potentially catastrophic events, he notes, "Exactly what would cause these sorts of changes or what effects they would have are not well-understood, although the chance of any one of them happening seems low. But they do have the potential to happen relatively quickly, and if they did, the costs could be substantial. Only a few studies of climate change have examined these issues."

Adaptation is included both implicitly and explicitly in FUND. Explicit adaptation is seen in the agriculture and sea level rise sectors. Implicit adaptation is included in sectors such as energy and human health, where wealthier populations are assumed to be less vulnerable to climate impacts. For example, the damages to agriculture are the sum of three effects: (1) those due to the rate of temperature change (damages are always positive); (2) those due to the level of temperature change (damages can be positive or negative depending on region and temperature); and (3) those from CO_2 fertilization (damages are generally negative but diminishing to zero).

Adaptation is incorporated into FUND by allowing damages to be smaller if climate change happens more slowly. The combined effect of CO_2 fertilization in the agricultural sector, positive impacts to some regions from higher temperatures, and sufficiently slow increases in temperature across these sectors can result in negative economic damages from climate change.

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[e] In the deterministic version of FUND, the majority of damages are attributable to increased air conditioning demand, while reduced cold stress in Europe, North America, and Central and East Asia results in health benefits in those regions at low to moderate levels of warming (Warren *et al*., 2006).

Damage Functions

To generate revised SCC values, we rely on the IAM modelers' current best judgments of how to represent the effects of climate change (represented by the increase in global-average surface temperature) on the consumption-equivalent value of both market and non-market goods (represented as a fraction of global GDP). We recognize that these representations are incomplete and highly uncertain. But given the paucity of data linking the physical impacts to economic damages, we were not able to identify a better way to translate changes in climate into net economic damages, short of launching our own research program.

The damage functions for the three IAMs are presented in Figure 14A.4.1 and Figure 14A.4.2, using the modeler's default scenarios and mean input assumptions. There are significant differences between the three models both at lower (Figure 14A.4.2) and higher (Figure 14A.4.1) increases in global-average temperature.

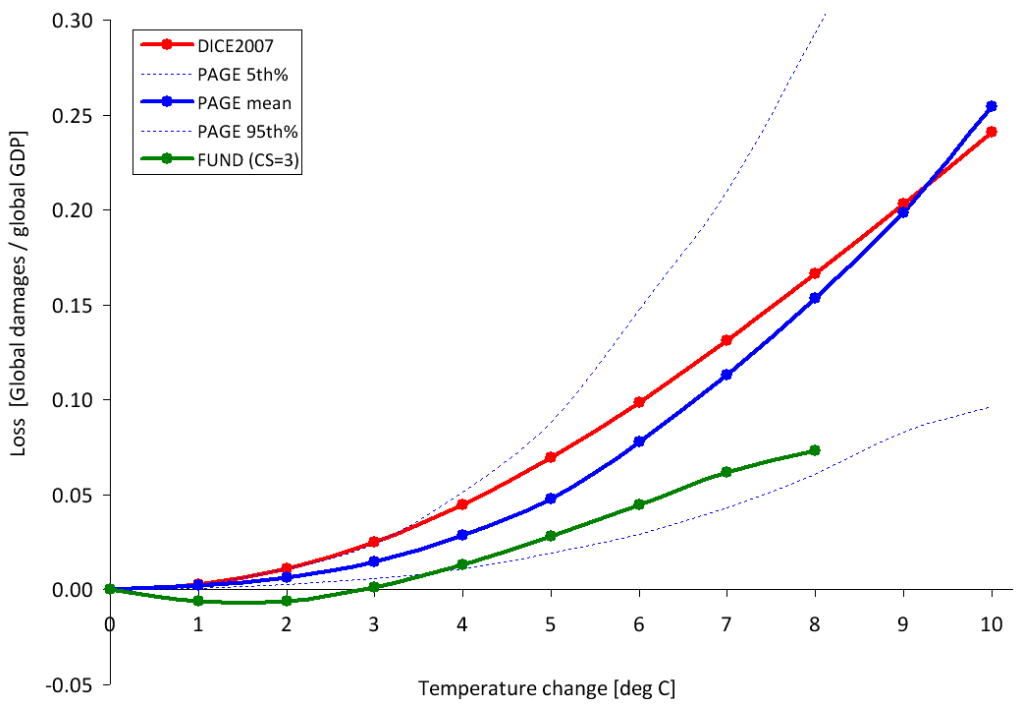

Figure 14A.4.1 Annual Consumption Loss as a Fraction of Global GDP in 2100 Due to an Increase in Annual Global Temperature in the DICE, FUND, and PAGE models[f]

[f] The x-axis represents increases in annual, rather than equilibrium, temperature, while the y-axis represents the annual stream of benefits as a share of global GDP. Each specific combination of climate sensitivity, socioeconomic, and emissions parameters will produce a different realization of damages for each IAM. The damage functions represented in Figures 1A and 1B are the outcome of default assumptions. For instance, under alternate assumptions, the damages from FUND may cross from negative to positive at less than or greater than 3 °C.

The lack of agreement among the models at lower temperature increases is underscored by the fact that the damages from FUND are well below the 5th percentile estimated by PAGE, while the damages estimated by DICE are roughly equal to the 95th percentile estimated by PAGE. This is significant because at higher discount rates we expect that a greater proportion of the SCC value is due to damages in years with lower temperature increases. For example, when the discount rate is 2.5 percent, about 45 percent of the 2010 SCC value in DICE is due to damages that occur in years when the temperature is less than or equal to 3 °C. This increases to approximately 55 percent and 80 percent at discount rates of 3 and 5 percent, respectively.

These differences underscore the need for a thorough review of damage functions—in particular, how the models incorporate adaptation, technological change, and catastrophic damages. Gaps in the literature make modifying these aspects of the models challenging, which highlights the need for additional research. As knowledge improves, the Federal government is committed to exploring how these (and other) models can be modified to incorporate more accurate estimates of damages.

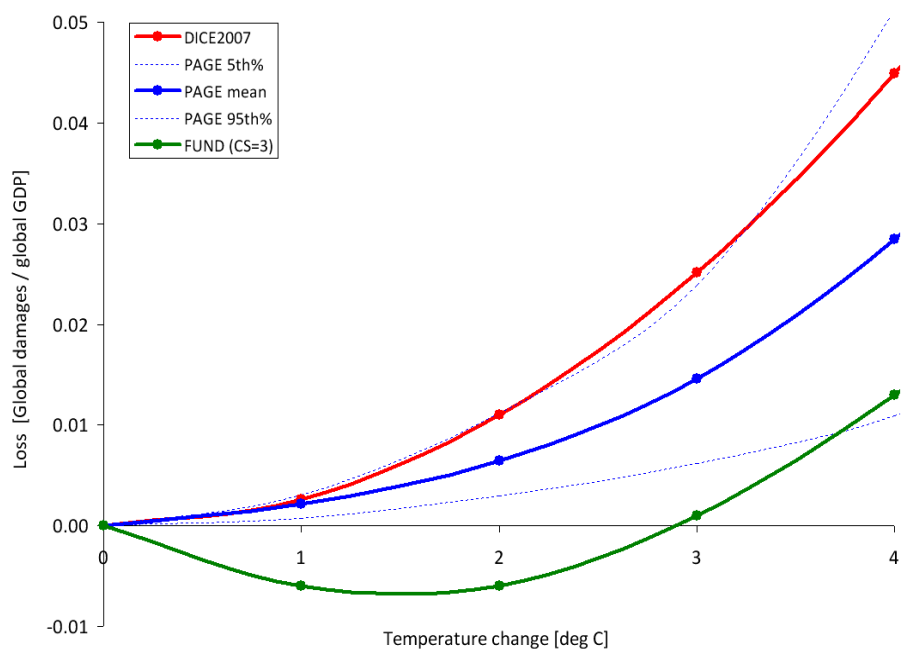

Figure 14A.4.2 Annual Consumption Loss for Lower Temperature Changes in DICE, FUND, and PAGE

14A.4.2 Global versus Domestic Measures of SCC

Because of the distinctive nature of the climate change problem, we center our current attention on a global measure of SCC. This approach is the same as that taken for the interim values, but it otherwise represents a departure from past practices, which tended to put greater

emphasis on a domestic measure of SCC (limited to impacts of climate change experienced within U.S. borders). As a matter of law, consideration of both global and domestic values is generally permissible; the relevant statutory provisions are usually ambiguous and allow selection of either measure.[g]

Global SCC

Under current OMB guidance contained in Circular A-4, analysis of economically significant proposed and final regulations from the domestic perspective is required, while analysis from the international perspective is optional. However, the climate change problem is highly unusual in at least two respects. First, it involves a global externality: emissions of most greenhouse gases contribute to damages around the world even when they are emitted in the United States. Consequently, to address the global nature of the problem, the SCC must incorporate the full (global) damages caused by GHG emissions. Second, climate change presents a problem that the United States alone cannot solve. Even if the United States were to reduce its greenhouse gas emissions to zero, that step would be far from enough to avoid substantial climate change. Other countries would also need to take action to reduce emissions if significant changes in the global climate are to be avoided. Emphasizing the need for a global solution to a global problem, the United States has been actively involved in seeking international agreements to reduce emissions and in encouraging other nations, including emerging major economies, to take significant steps to reduce emissions. When these considerations are taken as a whole, the interagency group concluded that a global measure of the benefits from reducing U.S. emissions is preferable.

When quantifying the damages associated with a change in emissions, a number of analysts (*e.g.*, Anthoff, *et al*. 2009a) employ "equity weighting" to aggregate changes in consumption across regions. This weighting takes into account the relative reductions in wealth in different regions of the world. A per-capita loss of $500 in GDP, for instance, is weighted more heavily in a country with a per-capita GDP of $2,000 than in one with a per-capita GDP of $40,000. The main argument for this approach is that a loss of $500 in a poor country causes a greater reduction in utility or welfare than does the same loss in a wealthy nation. Notwithstanding the theoretical claims on behalf of equity weighting, the interagency group concluded that this approach would not be appropriate for estimating a SCC value used in domestic regulatory analysis.[h] For this reason, the group concluded that using the global (rather than domestic) value, without equity weighting, is the appropriate approach.

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[g] It is true that federal statutes are presumed not to have extraterritorial effect, in part to ensure that the laws of the United States respect the interests of foreign sovereigns. But use of a global measure for the SCC does not give extraterritorial effect to federal law and hence does not intrude on such interests.

[h] It is plausible that a loss of $X inflicts more serious harm on a poor nation than on a wealthy one, but development of the appropriate "equity weight" is challenging. Emissions reductions also impose costs, and hence a full account would have to consider that a given cost of emissions reductions imposes a greater utility or welfare loss on a poor nation than on a wealthy one. Even if equity weighting—for both the costs and benefits of emissions reductions—is appropriate when considering the utility or welfare effects of international action, the interagency group concluded that it should not be used in developing an SCC for use in regulatory policy at this time.

Domestic SCC

As an empirical matter, the development of a domestic SCC is greatly complicated by the relatively few region- or country-specific estimates of the SCC in the literature. One potential source of estimates comes from the FUND model. The resulting estimates suggest that the ratio of domestic to global benefits of emission reductions varies with key parameter assumptions. For example, with a 2.5 or 3 percent discount rate, the U.S. benefit is about 7-10 percent of the global benefit, on average, across the scenarios analyzed. Alternatively, if the fraction of GDP lost due to climate change is assumed to be similar across countries, the domestic benefit would be proportional to the U.S. share of global GDP, which is currently about 23 percent.[i]

On the basis of this evidence, the interagency workgroup determined that a range of values from 7 to 23 percent should be used to adjust the global SCC to calculate domestic effects. Reported domestic values should use this range. It is recognized that these values are approximate, provisional, and highly speculative. There is no a priori reason why domestic benefits should be a constant fraction of net global damages over time. Further, FUND does not account for how damages in other regions could affect the United States (*e.g.*, global migration, economic and political destabilization). If more accurate methods for calculating the domestic SCC become available, the Federal government will examine these to determine whether to update its approach.

14A.4.3 Valuing Non-CO_2 Emissions

While CO_2 is the most prevalent greenhouse gas emitted into the atmosphere, the U.S. included five other greenhouse gases in its recent endangerment finding: methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. The climate impact of these gases is commonly discussed in terms of their 100-year global warming potential (GWP). GWP measures the ability of different gases to trap heat in the atmosphere (*i.e.*, radiative forcing per unit of mass) over a particular timeframe relative to CO_2. However, because these gases differ in both radiative forcing and atmospheric lifetimes, their relative damages are not constant over time. For example, because methane has a short lifetime, its impacts occur primarily in the near term and thus are not discounted as heavily as those caused by longer-lived gases. Impacts other than temperature change also vary across gases in ways that are not captured by GWP. For instance, CO_2 emissions, unlike methane and other greenhouse gases, contribute to ocean acidification. Likewise, damages from methane emissions are not offset by the positive effect of CO_2 fertilization. Thus, transforming gases into CO_2-equivalents using GWP, and then multiplying the carbon-equivalents by the SCC, would not result in accurate estimates of the social costs of non-CO_2 gases.

In light of these limitations, and the significant contributions of non-CO_2 emissions to climate change, further research is required to link non-CO_2 emissions to economic impacts. Such work would feed into efforts to develop a monetized value of reductions in non-CO_2 greenhouse gas emissions. As part of ongoing work to further improve the SCC estimates, the

[i] Based on 2008 GDP (in current US dollars) from the *World Bank Development Indicators Report*.

interagency group hopes to develop methods to value these other greenhouse gases. The goal is to develop these estimates by the time we issue revised SCC estimates for carbon dioxide emissions.

14A.4.4 Equilibrium Climate Sensitivity

Equilibrium climate sensitivity (ECS) is a key input parameter for the DICE, PAGE, and FUND models.[j] It is defined as the long-term increase in the annual global-average surface temperature from a doubling of atmospheric CO_2 concentration relative to pre-industrial levels (or stabilization at a concentration of approximately 550 parts per million (ppm)). Uncertainties in this important parameter have received substantial attention in the peer-reviewed literature.

The most authoritative statement about equilibrium climate sensitivity appears in the Fourth Assessment Report of the Intergovernmental Panel on Climate Change (IPCC):

> *Basing our assessment on a combination of several independent lines of evidence…including observed climate change and the strength of known feedbacks simulated in [global climate models], we conclude that the global mean equilibrium warming for doubling CO_2, or 'equilibrium climate sensitivity', is likely to lie in the range 2 °C to 4.5 °C, with a most likely value of about 3 °C. Equilibrium climate sensitivity is very likely larger than 1.5 °C.* [k]
>
> *For fundamental physical reasons as well as data limitations, values substantially higher than 4.5 °C still cannot be excluded, but agreement with observations and proxy data is generally worse for those high values than for values in the 2 °C to 4.5 °C range.* (Meehl *et al*., 2007, p 799)

After consulting with several lead authors of this chapter of the IPCC report, the interagency workgroup selected four candidate probability distributions and calibrated them to be consistent with the above statement: Roe and Baker (2007), log-normal, gamma, and Weibull. Table 14A.4.1 included below gives summary statistics for the four calibrated distributions.

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[j] The equilibrium climate sensitivity includes the response of the climate system to increased greenhouse gas concentrations over the short to medium term (up to 100-200 years), but it does not include long-term feedback effects due to possible large-scale changes in ice sheets or the biosphere, which occur on a time scale of many hundreds to thousands of years (*e.g.*, Hansen *et al*. 2007).

[k] This is in accord with the judgment that it "is likely to lie in the range 2 °C to 4.5 °C" and the IPCC definition of "likely" as greater than 66 percent probability (Le Treut *et al*.2007). "Very likely" indicates a greater than 90 percent probability.

Table 14A.4.1 Summary Statistics for Four Calibrated Climate Sensitivity Distributions

	Roe & Baker	Log-normal	Gamma	Weibull
Pr(ECS < 1.5°C)	0.013	0.050	0.070	0.102
Pr(2°C < ECS < 4.5°C)	0.667	0.667	0.667	0.667
5th percentile	1.72	1.49	1.37	1.13
10th percentile	1.91	1.74	1.65	1.48
Mode	2.34	2.52	2.65	2.90
Median (50th percentile)	3.00	3.00	3.00	3.00
Mean	3.50	3.28	3.19	3.07
90th percentile	5.86	5.14	4.93	4.69
95th percentile	7.14	5.97	5.59	5.17

Each distribution was calibrated by applying three constraints from the IPCC:

(1) a median equal to 3°C, to reflect the judgment of "a most likely value of about 3 °C";[l]
(2) two-thirds probability that the equilibrium climate sensitivity lies between 2 and 4.5 °C; and
(3) zero probability that it is less than 0°C or greater than 10°C (see Hegerl *et al*. 2006, p. 721).

We selected the calibrated Roe and Baker distribution from the four candidates for two reasons. First, the Roe and Baker distribution is the only one of the four that is based on a theoretical understanding of the response of the climate system to increased greenhouse gas concentrations (Roe and Baker 2007, Roe 2008). In contrast, the other three distributions are mathematical functions that are arbitrarily chosen based on simplicity, convenience, and general shape. The Roe and Baker distribution results from three assumptions about climate response: (1) absent feedback effects, the equilibrium climate sensitivity is equal to 1.2 °C; (2) feedback factors are proportional to the change in surface temperature; and (3) uncertainties in feedback factors are normally distributed. There is widespread agreement on the first point and the second and third points are common assumptions.

Second, the calibrated Roe and Baker distribution better reflects the IPCC judgment that "values substantially higher than 4.5°C still cannot be excluded." Although the IPCC made no quantitative judgment, the 95th percentile of the calibrated Roe & Baker distribution (7.1 °C) is much closer to the mean and the median (7.2 °C) of the 95th percentiles of 21 previous studies summarized by Newbold and Daigneault (2009). It is also closer to the mean (7.5 °C) and

[l] Strictly speaking, "most likely" refers to the mode of a distribution rather than the median, but common usage would allow the mode, median, or mean to serve as candidates for the central or "most likely" value and the IPCC report is not specific on this point. For the distributions we considered, the median was between the mode and the mean. For the Roe and Baker distribution, setting the median equal to 3°C, rather than the mode or mean, gave a 95th percentile that is more consistent with IPCC judgments and the literature. For example, setting the mean and mode equal to 3°C produced 95th percentiles of 5.6 and 8.6 °C, respectively, which are in the lower and upper end of the range in the literature. Finally, the median is closer to 3°C than is the mode for the truncated distributions selected by the IPCC (Hegerl, *et al*., 2006); the average median is 3.1 °C and the average mode is 2.3 °C, which is most consistent with a Roe and Baker distribution with the median set equal to 3 °C.

median (7.9 °C) of the nine truncated distributions examined by the IPCC (Hegerl, *et al*., 2006) than are the 95th percentiles of the three other calibrated distributions (5.2-6.0 °C).

Finally, we note the IPCC judgment that the equilibrium climate sensitivity "is very likely larger than 1.5°C." Although the calibrated Roe & Baker distribution, for which the probability of equilibrium climate sensitivity being greater than 1.5 °C is almost 99 percent, is not inconsistent with the IPCC definition of "very likely" as "greater than 90 percent probability," it reflects a greater degree of certainty about very low values of ECS than was expressed by the IPCC.

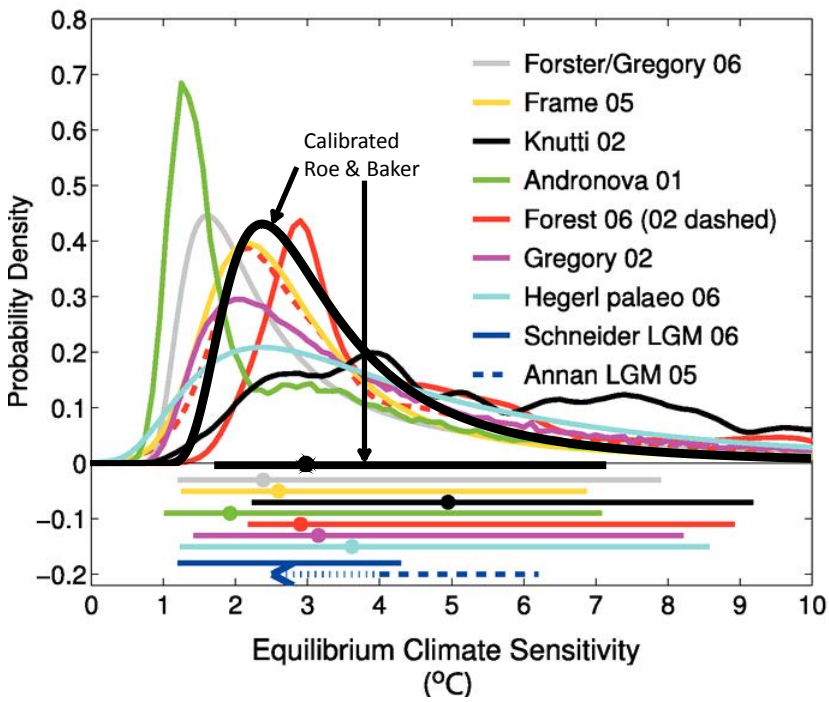

Figure 14A.4.3 Estimates of the Probability Density Function for Equilibrium Climate Sensitivity (°C)

To show how the calibrated Roe and Baker distribution compares to different estimates of the probability distribution function of equilibrium climate sensitivity in the empirical literature, Figure 14A.4.3 (above) overlays it on Figure 9.20 from the IPCC Fourth Assessment Report. These functions are scaled to integrate to unity between 0 °C and 10 °C. The horizontal bars show the respective 5 percent to 95 percent ranges; dots indicate the median estimate.[m]

[m] The estimates based on instrumental data are from Andronova and Schlesinger (2001), Forest *et al*. (2002; dashed line, anthropogenic forcings only), Forest *et al*. (2006; solid line, anthropogenic and natural forcings), Gregory *et al*. (2002a), Knutti *et al*. (2002), Frame *et al*. (2005), and Forster and Gregory (2006). Hegerl *et al*. (2006) are based on multiple palaeoclimatic reconstructions of north hemisphere mean temperatures over the last 700 years. Also shown are the 5-95 percent approximate ranges for two estimates from the last glacial maximum (dashed, Annan *et al*. 2005; solid, Schneider von Deimling *et al*. 2006), which are based on models with different structural properties.

14A.4.5 Socioeconomic and Emissions Trajectories

Another key issue considered by the interagency group is how to select the set of socioeconomic and emissions parameters for use in PAGE, DICE, and FUND. Socioeconomic pathways are closely tied to climate damages because, all else equal, more and wealthier people tend to emit more greenhouse gases and also have a higher (absolute) willingness to pay to avoid climate disruptions. For this reason, we consider how to model several input parameters in tandem: GDP, population, CO_2 emissions, and non-CO_2 radiative forcing. A wide variety of scenarios have been developed and used for climate change policy simulations (*e.g.*, SRES 2000, CCSP 2007, EMF 2009). In determining which scenarios are appropriate for inclusion, we aimed to select scenarios that span most of the plausible ranges of outcomes for these variables.

To accomplish this task in a transparent way, we decided to rely on the recent Stanford Energy Modeling Forum exercise, EMF-22. EMF-22 uses ten well-recognized models to evaluate substantial, coordinated global action to meet specific stabilization targets. A key advantage of relying on these data is that GDP, population, and emission trajectories are internally consistent for each model and scenario evaluated. The EMF-22 modeling effort also is preferable to the IPCC SRES due to their age (SRES were developed in 1997) and the fact that 3 of 4 of the SRES scenarios are now extreme outliers in one or more variables. Although the EMF-22 scenarios have not undergone the same level of scrutiny as the SRES scenarios, they are recent, peer-reviewed, published, and publicly available.

To estimate the SCC for use in evaluating domestic policies that will have a small effect on global cumulative emissions, we use socioeconomic and emission trajectories that span a range of plausible scenarios. Five trajectories were selected from EMF-22 (see Table 14A.4.2 below). Four of these represent potential business-as-usual (BAU) growth in population, wealth, and emissions and are associated with CO_2 (only) concentrations ranging from 612 to 889 ppm in 2100. One represents an emissions pathway that achieves stabilization at 550 ppm CO_2e (*i.e.*, CO_2-only concentrations of 425 – 484 ppm or a radiative forcing of 3.7 W/m^2) in 2100, a lower-than-BAU trajectory.[n] Out of the 10 models included in the EMF-22 exercise, we selected the trajectories used by MiniCAM, MESSAGE, IMAGE, and the optimistic scenario from MERGE. For the BAU pathways, we used the GDP, population, and emission trajectories from each of these four models. For the 550 ppm CO_2e scenario, we averaged the GDP, population, and emission trajectories implied by these same four models.

[n] Such an emissions path would be consistent with widespread action by countries to mitigate GHG emissions, though it could also result from technological advances. It was chosen because it represents the most stringent case analyzed by the EMF-22 where all the models converge: a 550 ppm, not to exceed, full participation scenario.

Table 14A.4.2 Socioeconomic and Emissions Projections from Select EMF-22 Reference Scenarios

Reference Fossil and Industrial CO_2 Emissions ($GtCO_2$/yr)

EMF – 22 Based Scenarios	2000	2010	2020	2030	2050	2100
IMAGE	26.6	31.9	36.9	40.0	45.3	60.1
MERGE Optimistic	24.6	31.5	37.6	45.1	66.5	117.9
MESSAGE	26.8	29.2	37.6	42.1	43.5	42.7
MiniCAM	26.5	31.8	38.0	45.1	57.8	80.5
550 ppm average	26.2	31.1	33.2	32.4	20.0	12.8

Reference GDP (using market exchange rates in trillion 2005$)[o]

EMF – 22 Based Scenarios	2000	2010	2020	2030	2050	2100
IMAGE	38.6	53.0	73.5	97.2	156.3	396.6
MERGE Optimistic	36.3	45.9	59.7	76.8	122.7	268.0
MESSAGE	38.1	52.3	69.4	91.4	153.7	334.9
MiniCAM	36.1	47.4	60.8	78.9	125.7	369.5
550 ppm average	37.1	49.6	65.6	85.5	137.4	337.9

Global Population (billions)

EMF – 22 Based Scenarios	2000	2010	2020	2030	2050	2100
IMAGE	6.1	6.9	7.6	8.2	9.0	9.1
MERGE Optimistic	6.0	6.8	7.5	8.2	9.0	9.7
MESSAGE	6.1	6.9	7.7	8.4	9.4	10.4
MiniCAM	6.0	6.8	7.5	8.1	8.8	8.7
550 ppm average	6.1	6.8	7.6	8.2	8.7	9.1

We explore how sensitive the SCC is to various assumptions about how the future will evolve without prejudging what is likely to occur. The interagency group considered formally assigning probability weights to different states of the world, but this proved challenging to do in an analytically rigorous way given the dearth of information on the likelihood of a full range of future socioeconomic pathways.

[o] While the EMF-22 models used market exchange rates (MER) to calculate global GDP, it is also possible to use purchasing power parity (PPP). PPP takes into account the different price levels across countries, so it more accurately describes relative standards of living across countries. MERs tend to make low-income countries appear poorer than they actually are. Because many models assume convergence in per capita income over time, use of MER-adjusted GDP gives rise to projections of higher economic growth in low income countries. There is an ongoing debate about how much this will affect estimated climate impacts. Critics of the use of MER argue that it leads to overstated economic growth and hence a significant upward bias in projections of greenhouse gas emissions, and unrealistically high future temperatures (*e.g.*, Castles and Henderson 2003). Others argue that convergence of the emissions-intensity gap across countries at least partially offset the overstated income gap so that differences in exchange rates have less of an effect on emissions (Holtsmark and Alfsen, 2005; Tol, 2006). Nordhaus (2007b) argues that the ideal approach is to use superlative PPP accounts (*i.e.*, using cross-sectional PPP measures for relative incomes and outputs and national accounts price and quantity indexes for time-series extrapolations). However, he notes that it important to keep this debate in perspective; it is by no means clear that exchange-rate-conversion issues are as important as uncertainties about population, technological change, or the many geophysical uncertainties.

There are a number of caveats. First, EMF BAU scenarios represent the modelers' judgment of the most likely pathway absent mitigation policies to reduce greenhouse gas emissions, rather than the wider range of possible outcomes. Nevertheless, these views of the most likely outcome span a wide range, from the more optimistic (*e.g.*, abundant low-cost, low-carbon energy) to more pessimistic (*e.g.*, constraints on the availability of nuclear and renewables).[p] Second, the socioeconomic trajectories associated with a 550 ppm CO_2e concentration scenario are not derived from an assessment of what policy is optimal from a benefit-cost standpoint. Rather, it is indicative of one possible future outcome. The emission trajectories underlying some BAU scenarios (*e.g.*, MESSAGE's 612 ppm) also are consistent with some modest policy action to address climate change.[q] We chose not to include socioeconomic trajectories that achieve even lower GHG concentrations at this time, given the difficulty many models had in converging to meet these targets.

For comparison purposes, the Energy Information Agency in its 2009 Annual Energy Outlook projected that global carbon dioxide emissions will grow to 30.8, 35.6, and 40.4 gigatons in 2010, 2020, and 2030, respectively, while world GDP is projected to be $51.8, $71.0 and $93.9 trillion (in 2005 dollars using market exchange rates) in 2010, 2020, and 2030, respectively. These projections are consistent with one or more EMF-22 scenarios. Likewise, the United Nations' 2008 Population Prospect projects population will grow from 6.1 billion people in 2000 to 9.1 billion people in 2050, which is close to the population trajectories for the IMAGE, MiniCAM, and MERGE models.

In addition to fossil and industrial CO_2 emissions, each EMF scenario provides projections of methane, nitrous oxide, fluorinated greenhouse gases, and net land use CO_2 emissions out to 2100. These assumptions also are used in the three models while retaining the default radiative forcings due to other factors (*e.g.*, aerosols and other gases). See the Annex for greater detail.

14A.4.6 Discount Rate

The choice of a discount rate, especially over long periods of time, raises highly contested and exceedingly difficult questions of science, economics, philosophy, and law. Although it is well understood that the discount rate has a large influence on the current value of future damages, there is no consensus about what rates to use in this context. Because carbon dioxide emissions are long-lived, subsequent damages occur over many years. In calculating the SCC, we first estimate the future damages to agriculture, human health, and other market and non-market sectors from an additional unit of carbon dioxide emitted in a particular year in terms

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[p] For instance, in the MESSAGE model's reference case total primary energy production from nuclear, biomass, and non-biomass renewables is projected to increase from about 15 percent of total primary energy in 2000 to 54 percent in 2100. In comparison, the MiniCAM reference case shows 10 percent in 2000 and 21 percent in 2100.

[q] For example, MiniCAM projects if all non-US OECD countries reduce CO_2 emissions to 83 percent below 2005 levels by 2050 (per the G-8 agreement) but all other countries continue along a BAU path CO_2 concentrations in 2100 would drop from 794 ppmv in its reference case to 762 ppmv.

of reduced consumption (or consumption equivalents) due to the impacts of elevated temperatures, as represented in each of the three IAMs. Then we discount the stream of future damages to its present value in the year when the additional unit of emissions was released using the selected discount rate, which is intended to reflect society's marginal rate of substitution between consumption in different time periods.

For rules with both intra- and intergenerational effects, agencies traditionally employ constant discount rates of both 3 percent and 7 percent in accordance with OMB Circular A-4. As Circular A-4 acknowledges, however, the choice of discount rate for intergenerational problems raises distinctive problems and presents considerable challenges. After reviewing those challenges, Circular A-4 states, "If your rule will have important intergenerational benefits or costs you might consider a further sensitivity analysis using a lower but positive discount rate in addition to calculating net benefits using discount rates of 3 and 7 percent." For the specific purpose of developing the SCC, we adapt and revise that approach here.

Arrow *et al*. (1996) outlined two main approaches to determine the discount rate for climate change analysis, which they labeled "descriptive" and "prescriptive." The descriptive approach reflects a positive (non-normative) perspective based on observations of people's actual choices—*e.g.*, savings versus consumption decisions over time, and allocations of savings among more and less risky investments. Advocates of this approach generally call for inferring the discount rate from market rates of return "because of a lack of justification for choosing a social welfare function that is any different than what decision makers [individuals] actually use" (Arrow *et al*. 1996).

One theoretical foundation for the cost-benefit analyses in which the social cost of carbon will be used—the Kaldor-Hicks potential-compensation test—also suggests that market rates should be used to discount future benefits and costs, because it is the market interest rate that would govern the returns potentially set aside today to compensate future individuals for climate damages that they bear (*e.g.*, Just *et al*. 2004). As some have noted, the word "potentially" is an important qualification; there is no assurance that such returns will actually be set aside to provide compensation, and the very idea of compensation is difficult to define in the intergenerational context. On the other hand, societies provide compensation to future generations through investments in human capital and the resulting increase in knowledge, as well as infrastructure and other physical capital.

The prescriptive approach specifies a social welfare function that formalizes the normative judgments that the decision-maker wants explicitly to incorporate into the policy evaluation—*e.g.*, how inter-personal comparisons of utility should be made, and how the welfare of future generations should be weighed against that of the present generation. Ramsey (1928), for example, has argued that it is "ethically indefensible" to apply a positive pure rate of time preference to discount values across generations, and many agree with this view.

Other concerns also motivate making adjustments to descriptive discount rates. In particular, it has been noted that the preferences of future generations with regard to

consumption versus environmental amenities may not be the same as those today, making the current market rate on consumption an inappropriate metric by which to discount future climate-related damages. Others argue that the discount rate should be below market rates to correct for market distortions and uncertainties or inefficiencies in intergenerational transfers of wealth, which in the Kaldor-Hicks logic are presumed to compensate future generations for damage (a potentially controversial assumption, as noted above) (Arrow *et al*. 1996, Weitzman 1999).

Further, a legitimate concern about both descriptive and prescriptive approaches is that they tend to obscure important heterogeneity in the population. The utility function that underlies the prescriptive approach assumes a representative agent with perfect foresight and no credit constraints. This is an artificial rendering of the real world that misses many of the frictions that characterize individuals' lives and indeed the available descriptive evidence supports this. For instance, many individuals smooth consumption by borrowing with credit cards that have relatively high rates. Some are unable to access traditional credit markets and rely on payday lending operations or other high-cost forms of smoothing consumption. Whether one puts greater weight on the prescriptive or descriptive approach, the high interest rates that credit-constrained individuals accept suggest that some account should be given to the discount rates revealed by their behavior.

We draw on both approaches but rely primarily on the descriptive approach to inform the choice of discount rate. With recognition of its limitations, we find this approach to be the most defensible and transparent given its consistency with the standard contemporary theoretical foundations of benefit-cost analysis and with the approach required by OMB's existing guidance. The logic of this framework also suggests that market rates should be used for discounting future consumption-equivalent damages. Regardless of the theoretical approach used to derive the appropriate discount rate(s), we note the inherent conceptual and practical difficulties of adequately capturing consumption trade-offs over many decades or even centuries. While relying primarily on the descriptive approach in selecting specific discount rates, the interagency group has been keenly aware of the deeply normative dimensions of both the debate over discounting in the intergenerational context and the consequences of selecting one discount rate over another.

Historically Observed Interest Rates

In a market with no distortions, the return to savings would equal the private return on investment, and the market rate of interest would be the appropriate choice for the social discount rate. In the real world risk, taxes, and other market imperfections drive a wedge between the risk-free rate of return on capital and the consumption rate of interest. Thus, the literature recognizes two conceptual discount concepts—the consumption rate of interest and the opportunity cost of capital.

According to OMB's Circular A-4, it is appropriate to use the rate of return on capital when a regulation is expected to displace or alter the use of capital in the private sector. In this case, OMB recommends Agencies use a discount rate of 7 percent. When regulation is expected to primarily affect private consumption—for instance, via higher prices for goods and services—

a lower discount rate of 3 percent is appropriate to reflect how private individuals trade-off current and future consumption.

The interagency group examined the economics literature and concluded that the consumption rate of interest is the correct concept to use in evaluating the benefits and costs of a marginal change in carbon emissions (see Lind 1990, Arrow *et al* 1996, and Arrow 2000). The consumption rate of interest also is appropriate when the impacts of a regulation are measured in consumption (-equivalent) units, as is done in the three integrated assessment models used for estimating the SCC.

Individuals use a variety of savings instruments that vary with risk level, time horizon, and tax characteristics. The standard analytic framework used to develop intuition about the discount rate typically assumes a representative agent with perfect foresight and no credit constraints. The risk-free rate is appropriate for discounting certain future benefits or costs, but the benefits calculated by IAMs are uncertain. To use the risk-free rate to discount uncertain benefits, these benefits first must be transformed into "certainty equivalents," that is the maximum certain amount that we would exchange for the uncertain amount. However, the calculation of the certainty-equivalent requires first estimating the correlation between the benefits of the policy and baseline consumption.

If the IAM projections of future impacts represent expected values (not certainty-equivalent values), then the appropriate discount rate generally does not equal the risk-free rate. If the benefits of the policy tend to be high in those states of the world in which consumption is low, then the certainty-equivalent benefits will be higher than the expected benefits (and vice versa). Since many (though not necessarily all) of the important impacts of climate change will flow through market sectors such as agriculture and energy, and since willingness to pay for environmental protections typically increases with income, we might expect a positive (though not necessarily perfect) correlation between the net benefits from climate policies and market returns. This line of reasoning suggests that the proper discount rate would exceed the riskless rate. Alternatively, a negative correlation between the returns to climate policies and market returns would imply that a discount rate below the riskless rate is appropriate.

This discussion suggests that both the post-tax riskless and risky rates can be used to capture individuals' consumption-equivalent interest rate. As a measure of the post-tax riskless rate, we calculate the average real return from Treasury notes over the longest time period available (those from Newell and Pizer 2003) and adjust for Federal taxes (the average marginal rate from tax years 2003 through 2006 is around 27 percent).[r] This calculation produces a real interest rate of about 2.7 percent, which is roughly consistent with Circular A-4's

[r] The literature argues for a risk-free rate on government bonds as an appropriate measure of the consumption rate of interest. Arrow (2000) suggests that it is roughly 3-4 percent. OMB cites evidence of a 3.1 percent pre-tax rate for 10-year Treasury notes in the A-4 guidance. Newell and Pizer (2003) find real interest rates between 3.5 and 4 percent for 30-year Treasury securities.

recommendation to use 3 percent to represent the consumption rate of interest.[s] A measure of the post-tax risky rate for investments whose returns are positively correlated with overall equity market returns can be obtained by adjusting pre-tax rates of household returns to risky investments (approximately 7 percent) for taxes, which yields a real rate of roughly 5 percent.[t]

The Ramsey Equation

Ramsey discounting also provides a useful framework to inform the choice of a discount rate. Under this approach, the analyst applies either positive or normative judgments in selecting values for the key parameters of the Ramsey equation: η (coefficient of relative risk aversion or elasticity of the marginal utility of consumption) and ρ (pure rate of time preference).[u] These are then combined with g (growth rate of per-capita consumption) to equal the interest rate at which future monetized damages are discounted: $\rho + \eta \cdot g$.[v] In the simplest version of the Ramsey model, with an optimizing representative agent with perfect foresight, what we are calling the "Ramsey discount rate," $\rho + \eta \cdot g$, will be equal to the rate of return to capital, *i.e.*, the market interest rate.

A review of the literature provides some guidance on reasonable parameter values for the Ramsey discounting equation, based on both prescriptive and descriptive approaches.

- η. Most papers in the climate change literature adopt values for η in the range of 0.5 to 3 (Weitzman cites plausible values as those ranging from 1 to 4), although not all authors

[s] The positive approach reflects how individuals make allocation choices across time, but it is important to keep in mind that we wish to reflect preferences for society as a whole, which generally has a longer planning horizon.
[t] Cambell *et al* (2001) estimates that the annual real return from stocks for 1900-1995 was about 7 percent. The annual real rate of return for the S&P 500 from 1950 – 2008 was about 6.8 percent. In the absence of a better way to population-weight the tax rates, we use the middle of the 20 – 40 percent range to derive a post-tax interest rate (Kotlikoff and Rapson 2006).
[u] The parameter ρ measures the *pure rate of time preference*: people's behavior reveals a preference for an increase in utility today versus the future. Consequently, it is standard to place a lower weight on utility in the future. The parameter η captures *diminishing marginal utility*: consumption in the future is likely to be higher than consumption today, so diminishing marginal utility of consumption implies that the same monetary damage will cause a smaller reduction of utility for wealthier individuals, either in the future or in current generations. If $\eta = 0$, then a one dollar increase in income is equally valuable regardless of level of income; if $\eta = 1$, then a one percent increase in income is equally valuable no matter the level of income; and if $\eta > 1$, then a one percent increase in income is less valuable to wealthier individuals.
[v] In this case, g could be taken from the selected EMF socioeconomic scenarios or alternative assumptions about the rate of consumption growth.

articulate whether their choice is based on prescriptive or descriptive reasoning.[w] Dasgupta (2008) argues that η should be greater than 1 and may be as high as 3, because η equal to 1 suggests savings rates that do not conform to observed behavior.

- ρ. With respect to the pure rate of time preference, most papers in the climate change literature adopt values for ρ in the range of 0 to 3 percent per year. The very low rates tend to follow from moral judgments involving intergenerational neutrality. Some have argued that to use any value other than ρ = 0 would unjustly discriminate against future generations (*e.g.*, Arrow *et al*. 1996, Stern *et al*. 2006). However, even in an inter-generational setting, it may make sense to use a small positive pure rate of time preference because of the small probability of unforeseen cataclysmic events (Stern *et al*. 2006).

- g. A commonly accepted approximation is around 2 percent per year. For the socioeconomic scenarios used for this exercise, the EMF models assume that g is about 1.5-2 percent to 2100.

Some economists and non-economists have argued for constant discount rates below 2 percent based on the prescriptive approach. When grounded in the Ramsey framework, proponents of this approach have argued that a ρ of zero avoids giving preferential treatment to one generation over another. The choice of η has also been posed as an ethical choice linked to the value of an additional dollar in poorer countries compared to wealthier ones. Stern *et al*. (2006) applies this perspective through his choice of ρ = 0.1 percent per year, η = 1 and g = 1.3 percent per year, which yields an annual discount rate of 1.4 percent. In the context of permanent income savings behavior, however, Stern's assumptions suggest that individuals would save 93 percent of their income.[x]

Recently, Stern (2008) revisited the values used in Stern *et al*. (2006), stating that there is a case to be made for raising η due to the amount of weight lower values place on damages far in the future (over 90 percent of expected damages occur after 2200 with η = 1). Using Stern's assumption that ρ = 0.1 percent, combined with a η of 1.5 to 2 and his original growth rate, yields a discount rate of greater than 2 percent.

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[w] Empirical estimates of η span a wide range of values. A benchmark value of 2 is near the middle of the range of values estimated or used by Szpiro (1986), Hall and Jones (2007), Arrow (2007), Dasgupta (2006, 2008), Weitzman (2007, 2009), and Nordhaus (2008). However, Chetty (2006) developed a method of estimating η using data on labor supply behavior. He shows that existing evidence of the effects of wage changes on labor supply imposes a tight upper bound on the curvature of utility over wealth (CRRA < 2) with the mean implied value of 0.71 and concludes that the standard expected utility model cannot generate high levels of risk aversion without contradicting established facts about labor supply. Recent work has jointly estimated the components of the Ramsey equation. Evans and Sezer (2005) estimate η = 1.49 for 22 OECD countries. They also estimate ρ = 1.08 percent per year using data on mortality rates. Anthoff, *et al*. (2009b) estimate η = 1.18, and ρ = 1.4 percent. When they multiply the bivariate probability distributions from their work and Evans and Sezer (2005) together, they find η = 1.47, and ρ = 1.07.

[x] Stern (2008) argues that building in a positive rate of exogenous technical change over time reduces the implied savings rate and that η at or above 2 are inconsistent with observed behavior with regard to equity. (At the same time, adding exogenous technical change—all else equal—would increase g as well.)

We conclude that arguments made under the prescriptive approach can be used to justify discount rates between roughly 1.4 and 3.1 percent. In light of concerns about the most appropriate value for η, we find it difficult to justify rates at the lower end of this range under the Ramsey framework.

Accounting for Uncertainty in the Discount Rate

While the consumption rate of interest is an important driver of the benefits estimate, it is uncertain over time. Ideally, we would formally model this uncertainty, just as we do for climate sensitivity. Weitzman (1998, 2001) showed theoretically and Newell and Pizer (2003) and Groom *et al*. (2006) confirm empirically that discount rate uncertainty can have a large effect on net present values. A main result from these studies is that if there is a persistent element to the uncertainty in the discount rate (*e.g.*, the rate follows a random walk), then it will result in an effective (or certainty-equivalent) discount rate that declines over time. Consequently, lower discount rates tend to dominate over the very long term (see Weitzman 1998, 1999, 2001; Newell and Pizer 2003; Groom *et al*. 2006; Gollier 2008; Summers and Zeckhauser 2008; and Gollier and Weitzman 2009).

The proper way to model discount rate uncertainty remains an active area of research. Newell and Pizer (2003) employ a model of how long-term interest rates change over time to forecast future discount rates. Their model incorporates some of the basic features of how interest rates move over time, and its parameters are estimated based on historical observations of long-term rates. Subsequent work on this topic, most notably Groom *et al*. (2006), uses more general models of interest rate dynamics to allow for better forecasts. Specifically, the volatility of interest rates depends on whether rates are currently low or high and the variation in the level of persistence over time.

While Newell and Pizer (2003) and Groom *et al* (2006) attempt formally to model uncertainty in the discount rate, others argue for a declining scale of discount rates applied over time (*e.g.*, Weitzman 2001, and the UK's "Green Book" for regulatory analysis). This approach uses a higher discount rate initially, but applies a graduated scale of lower discount rates further out in time.[y] A key question that has emerged with regard to both of these approaches is the trade-off between potential time inconsistency and giving greater weight to far future outcomes (see the EPA Science Advisory Board's recent comments on this topic as part of its review of their *Guidelines for Economic Analysis*).[z]

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[y] For instance, the UK applies a discount rate of 3.5 percent to the first 30 years; 3 percent for years 31 - 75; 2.5 percent for years 76 - 125; 2 percent for years 126 - 200; 1.5 percent for years 201 - 300; and 1 percent after 300 years. As a sensitivity, it recommends a discount rate of 3 percent for the first 30 years, also decreasing over time.

[z] Uncertainty in future damages is distinct from uncertainty in the discount rate. Weitzman (2008) argues that Stern's choice of a low discount rate was "right for the wrong reasons." He demonstrates how the damages from a low probability, catastrophic event far in the future dominate the effect of the discount rate in a present value calculation and result in an infinite willingness-to-pay for mitigation today. Newbold and Daigneault, (2009) and Nordhaus (2009) find that Weitzman's result is sensitive to the functional forms chosen for climate sensitivity,

The Discount Rates Selected for Estimating SCC

In light of disagreement in the literature on the appropriate market interest rate to use in this context and uncertainty about how interest rates may change over time, we use three discount rates to span a plausible range of certainty-equivalent constant discount rates: 2.5, 3, and 5 percent per year. Based on the review in the previous sections, the interagency workgroup determined that these three rates reflect reasonable judgments under both descriptive and prescriptive approaches.

The central value, 3 percent, is consistent with estimates provided in the economics literature and OMB's Circular A-4 guidance for the consumption rate of interest. As previously mentioned, the consumption rate of interest is the correct discounting concept to use when future damages from elevated temperatures are estimated in consumption-equivalent units. Further, 3 percent roughly corresponds to the after-tax riskless interest rate. The upper value of 5 percent is included to represent the possibility that climate damages are positively correlated with market returns. Additionally, this discount rate may be justified by the high interest rates that many consumers use to smooth consumption across periods.

The low value, 2.5 percent, is included to incorporate the concern that interest rates are highly uncertain over time. It represents the average certainty-equivalent rate using the mean-reverting and random walk approaches from Newell and Pizer (2003) starting at a discount rate of 3 percent. Using this approach, the certainty equivalent is about 2.2 percent using the random walk model and 2.8 percent using the mean reverting approach.[aa] Without giving preference to a particular model, the average of the two rates is 2.5 percent. Further, a rate below the riskless rate would be justified if climate investments are negatively correlated with the overall market rate of return. Use of this lower value also responds to certain judgments using the prescriptive or normative approach and to ethical objections that have been raised about rates of 3 percent or higher.

14A.5 REVISED SCC ESTIMATES

Our general approach to estimating SCC values is to run the three integrated assessment models (FUND, DICE, and PAGE) using the following inputs agreed upon by the interagency group:

- A Roe and Baker distribution for the climate sensitivity parameter bounded between 0 and 10 with a median of 3 °C and a cumulative probability between 2 and 4.5 °C of two-thirds.
- Five sets of GDP, population, and carbon emissions trajectories based on EMF-22.
- Constant annual discount rates of 2.5, 3, and 5 percent.

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utility, and consumption. Summers and Zeckhauser (2008) argue that uncertainty in future damages can also work in the other direction by increasing the benefits of waiting to learn the appropriate level of mitigation required.

[aa] Calculations done by Pizer *et al*. using the original simulation program from Newell and Pizer (2003).

Because the climate sensitivity parameter is modeled probabilistically, and because PAGE and FUND incorporate uncertainty in other model parameters, the final output from each model run is a distribution over the SCC in year *t*.

For each of the IAMs, the basic computational steps for calculating the SCC in a particular year *t* are:

1. Input the path of emissions, GDP, and population from the selected EMF-22 scenarios, and the extrapolations based on these scenarios for post-2100 years.

2. Calculate the temperature effects and (consumption-equivalent) damages in each year resulting from the baseline path of emissions.

    a. In PAGE, the consumption-equivalent damages in each period are calculated as a fraction of the EMF GDP forecast, depending on the temperature in that period relative to the pre-industrial average temperature in each region.
    b. In FUND, damages in each period depend on both the level and the rate of temperature change in that period.
    c. In DICE, temperature affects both consumption and investment, so we first adjust the EMF GDP paths as follows: Using the Cobb-Douglas production function with the DICE2007 parameters, we extract the path of exogenous technical change implied by the EMF GDP and population paths, then we recalculate the baseline GDP path taking into account climate damages resulting from the baseline emissions path.

3. Add an additional unit of carbon emissions in year *t.* (The exact unit varies by model.)

4. Recalculate the temperature effects and damages expected in all years beyond *t* resulting from this adjusted path of emissions, as in step 2.

5. Subtract the damages computed in step 2 from those in step 4 in each year. (DICE is run in 10-year time steps, FUND in annual time steps, while the time steps in PAGE vary.)

6. Discount the resulting path of marginal damages back to the year of emissions using the agreed upon fixed discount rates.

7. Calculate the SCC as the net present value of the discounted path of damages computed in step 6, divided by the unit of carbon emissions used to shock the models in step 3.

8. Multiply by 12/44 to convert from dollars per ton of carbon to dollars per ton of CO_2 (2007 dollars) in DICE and FUND. (All calculations are done in tons of CO_2 in PAGE).

The steps above were repeated in each model for multiple future years to cover the time horizons anticipated for upcoming rulemaking analysis. To maintain consistency across the three IAMs, climate damages are calculated as lost consumption in each future year.

It is important to note that each of the three models has a different default end year. The default time horizon is 2200 for PAGE, 2595 for DICE, and 3000 for the latest version of FUND. This is an issue for the multi-model approach because differences in SCC estimates may arise simply due to the model time horizon. Many consider 2200 too short a time horizon because it could miss a significant fraction of damages under certain assumptions about the growth of marginal damages and discounting, so each model is run here through 2300. This step required a small adjustment in the PAGE model only. This step also required assumptions about GDP, population, and greenhouse gas emission trajectories after 2100, the last year for which these data are available from the EMF-22 models. (A more detailed discussion of these assumptions is included in the Annex.)

This exercise produces 45 separate distributions of the SCC for a given year, the product of 3 models, 3 discount rates, and 5 socioeconomic scenarios. This is clearly too many separate distributions for consideration in a regulatory impact analysis.

To produce a range of plausible estimates that still reflects the uncertainty in the estimation exercise, the distributions from each of the models and scenarios are equally weighed and combined to produce three separate probability distributions for SCC in a given year, one for each assumed discount rate. These distributions are then used to define a range of point estimates for the global SCC. In this way, no IAM or socioeconomic scenario is given greater weight than another. Because the literature shows that the SCC is quite sensitive to assumptions about the discount rate, and because no consensus exists on the appropriate rate to use in an intergenerational context, we present SCCs based on the average values across models and socioeconomic scenarios for each discount rate.

The interagency group selected four SCC values for use in regulatory analyses. Three values are based on the average SCC across models and socioeconomic and emissions scenarios at the 2.5, 3, and 5 percent discount rates. The fourth value is included to represent the higher-than-expected economic impacts from climate change further out in the tails of the SCC distribution. For this purpose, we use the SCC value for the 95th percentile at a 3 percent discount rate. (The full set of distributions by model and scenario combination is included in the Annex.) As noted above, the 3 percent discount rate is the central value, and so the central value that emerges is the average SCC across models at the 3 percent discount rate. For purposes of capturing the uncertainties involved in regulatory impact analysis, we emphasize the importance and value of considering the full range.

As previously discussed, low probability, high impact events are incorporated into the SCC values through explicit consideration of their effects in two of the three models as well as the use of a probability density function for equilibrium climate sensitivity. Treating climate sensitivity probabilistically results in more high-temperature outcomes, which in turn lead to higher projections of damages. Although FUND does not include catastrophic damages (in contrast to the other two models), its probabilistic treatment of the equilibrium climate sensitivity parameter will directly affect the non-catastrophic damages that are a function of the rate of temperature change.

In Table 14A.5.1, we begin by presenting SCC estimates for 2010 by model, scenario, and discount rate to illustrate the variability in the SCC across each of these input parameters. As expected, higher discount rates consistently result in lower SCC values, while lower discount rates result in higher SCC values for each socioeconomic trajectory. It is also evident that there are differences in the SCC estimated across the three main models. For these estimates, FUND produces the lowest estimates, while PAGE generally produces the highest estimates.

Table 14A.5.1 Disaggregated Social Cost of CO_2 Values by Model, Socioeconomic Trajectory, and Discount Rate for 2010 (in 2007 dollars)

	Discount rate:	**5%**	**3%**	**2.5%**	**3%**
Model	*Scenario*	Avg	Avg	Avg	95th
DICE	IMAGE	10.8	35.8	54.2	70.8
	MERGE	7.5	22.0	31.6	42.1
	Message	9.8	29.8	43.5	58.6
	MiniCAM	8.6	28.8	44.4	57.9
	550 Average	8.2	24.9	37.4	50.8
PAGE	IMAGE	8.3	39.5	65.5	142.4
	MERGE	5.2	22.3	34.6	82.4
	Message	7.2	30.3	49.2	115.6
	MiniCAM	6.4	31.8	54.7	115.4
	550 Average	5.5	25.4	42.9	104.7
FUND	IMAGE	-1.3	8.2	19.3	39.7
	MERGE	-0.3	8.0	14.8	41.3
	Message	-1.9	3.6	8.8	32.1
	MiniCAM	-0.6	10.2	22.2	42.6
	550 Average	-2.7	-0.2	3.0	19.4

These results are not surprising when compared to the estimates in the literature for the latest versions of each model. For example, adjusting the values from the literature that were used to develop interim SCC values to 2007 dollars for the year 2010 (assuming, as we did for the interim process, that SCC grows at 3 percent per year), FUND yields SCC estimates at or near zero for a 5 percent discount rate and around $9 per ton for a 3 percent discount rate. There are far fewer estimates using the latest versions of DICE and PAGE in the literature: Using similar adjustments to generate 2010 estimates, we calculate a SCC from DICE (based on Nordhaus 2008) of around $9 per ton for a 5 percent discount rate, and a SCC from PAGE (based on Hope 2006, 2008) close to $8 per ton for a 4 percent discount rate. Note that these comparisons are only approximate since the literature generally relies on Ramsey discounting, while we have assumed constant discount rates.[bb]

[bb] Nordhaus (2008) runs DICE2007 with $\rho = 1.5$ and $\eta = 2$. The default approach in PAGE2002 (version 1.4epm) treats ρ and η as random parameters, specified using a triangular distribution such that the min, mode, and max = 0.1, 1, and 2 for ρ, and 0.5, 1, and 2 for η, respectively. The FUND default value for η is 1, and Tol generates SCC

The SCC estimates from FUND are sensitive to differences in emissions paths but relatively insensitive to differences in GDP paths across scenarios, while the reverse is true for DICE and PAGE. This likely occurs because of several structural differences among the models. Specifically in DICE and PAGE, the fraction of economic output lost due to climate damages increases with the level of temperature alone, whereas in FUND the fractional loss also increases with the rate of temperature change. Furthermore, in FUND increases in income over time decrease vulnerability to climate change (a form of adaptation), whereas this does not occur in DICE and PAGE. These structural differences among the models make FUND more sensitive to the path of emissions and less sensitive to GDP compared to DICE and PAGE.

Figure 14A.5.1 shows that IMAGE has the highest GDP in 2100 while MERGE Optimistic has the lowest. The ordering of global GDP levels in 2100 directly corresponds to the rank ordering of SCC for PAGE and DICE. For FUND, the correspondence is less clear, a result that is to be expected given its less direct relationship between its damage function and GDP.

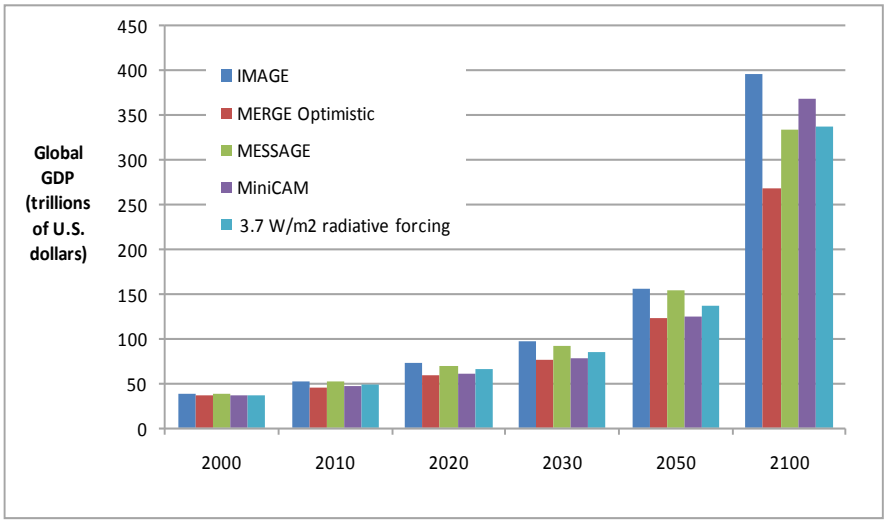

Figure 14A.5.1 Level of Global GDP across EMF Scenarios

Table 14A.5.2 shows the four selected SCC values in five-year increments from 2010 to 2050. Values for 2010, 2020, 2040, and 2050 are calculated by first combining all outputs (10,000 estimates per model run) from all scenarios and models for a given discount rate. Values for the years in between are calculated using a simple linear interpolation.

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estimates for values of ρ = 0, 1, and 3 in many recent papers (*e.g.*, Anthoff *et al*. 2009). The path of per-capita consumption growth, g, varies over time but is treated deterministically in two of the three models. In DICE, g is endogenous. Under Ramsey discounting, as economic growth slows in the future, the large damages from climate change that occur far out in the future are discounted at a lower rate than impacts that occur in the nearer term.

Table 14A.5.2 Social Cost of CO_2, 2010 – 2050 (in 2007 dollars)

Discount Year	5% Avg	3% Avg	2.5% Avg	3% 95th
2010	4.7	21.4	35.1	64.9
2015	5.7	23.8	38.4	72.8
2020	6.8	26.3	41.7	80.7
2025	8.2	29.6	45.9	90.4
2030	9.7	32.8	50.0	100.0
2035	11.2	36.0	54.2	109.7
2040	12.7	39.2	58.4	119.3
2045	14.2	42.1	61.7	127.8
2050	15.7	44.9	65.0	136.2

The SCC increases over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change. Note that this approach allows us to estimate the growth rate of the SCC directly using DICE, PAGE, and FUND rather than assuming a constant annual growth rate as was done for the interim estimates (using 3 percent). This helps to ensure that the estimates are internally consistent with other modeling assumptions. Table 14A.5.3 illustrates how the growth rate for these four SCC estimates varies over time. The full set of annual SCC estimates between 2010 and 2050 is reported in the Annex.

Table 14A.5.3 Changes in the Average Annual Growth Rates of SCC Estimates between 2010 and 2050

Average Annual Growth Rate (%)	**5%** Avg	**3%** Avg	**2.5%** Avg	**3.0%** 95th
2010-2020	3.6%	2.1%	1.7%	2.2%
2020-2030	3.7%	2.2%	1.8%	2.2%
2030-2040	2.7%	1.8%	1.6%	1.8%
2040-2050	2.1%	1.4%	1.1%	1.3%

While the SCC estimate grows over time, the future monetized value of emissions reductions in each year (the SCC in year *t* multiplied by the change in emissions in year *t*) must be discounted to the present to determine its total net present value for use in regulatory analysis. Damages from future emissions should be discounted at the same rate as that used to calculate the SCC estimates themselves to ensure internal consistency—*i.e.*, future damages from climate change, whether they result from emissions today or emissions in a later year, should be discounted using the same rate. For example, climate damages in the year 2020 that are

calculated using a SCC based on a 5 percent discount rate also should be discounted back to the analysis year using a 5 percent discount rate.[cc]

14A.6 LIMITATIONS OF THE ANALYSIS

As noted, any estimate of the SCC must be taken as provisional and subject to further refinement (and possibly significant change) in accordance with evolving scientific, economic, and ethical understandings. During the course of our modeling, it became apparent that there are several areas in particular need of additional exploration and research. These caveats, and additional observations in the following section, are necessary to consider when interpreting and applying the SCC estimates.

Incomplete treatment of non-catastrophic damages. The impacts of climate change are expected to be widespread, diverse, and heterogeneous. In addition, the exact magnitude of these impacts is uncertain because of the inherent complexity of climate processes, the economic behavior of current and future populations, and our inability to accurately forecast technological change and adaptation. Current IAMs do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature (some of which are discussed above) because of lack of precise information on the nature of damages and because the science incorporated into these models understandably lags behind the most recent research. Our ability to quantify and monetize impacts will undoubtedly improve with time. But it is also likely that even in future applications, a number of potentially significant damage categories will remain non-monetized. (Ocean acidification is one example of a potentially large damage from CO_2 emissions not quantified by any of the three models. Species and wildlife loss is another example that is exceedingly difficult to monetize.)

Incomplete treatment of potential catastrophic damages. There has been considerable recent discussion of the risk of catastrophic impacts and how best to account for extreme scenarios, such as the collapse of the Atlantic Meridional Overturning Circulation or the West Antarctic Ice Sheet, or large releases of methane from melting permafrost and warming oceans. Weitzman (2009) suggests that catastrophic damages are extremely large—so large, in fact, that the damages from a low probability, catastrophic event far in the future dominate the effect of the discount rate in a present value calculation and result in an infinite willingness-to-pay for mitigation today. However, Nordhaus (2009) concluded that the conditions under which Weitzman's results hold “are limited and do not apply to a wide range of potential uncertain scenarios."

Using a simplified IAM, Newbold and Daigneault (2009) confirmed the potential for large catastrophe risk premiums but also showed that the aggregate benefit estimates can be highly sensitive to the shapes of both the climate sensitivity distribution and the damage function at high temperature changes. Pindyck (2009) also used a simplified IAM to examine high-

[cc] However, it is possible that other benefits or costs of proposed regulations unrelated to CO_2 emissions will be discounted at rates that differ from those used to develop the SCC estimates.

impact, low-probability risks, using a right-skewed gamma distribution for climate sensitivity as well as an uncertain damage coefficient, but in most cases found only a modest risk premium. Given this difference in opinion, further research in this area is needed before its practical significance can be fully understood and a reasonable approach developed to account for such risks in regulatory analysis. (The next section discusses the scientific evidence on catastrophic impacts in greater detail.)

Uncertainty in extrapolation of damages to high temperatures: The damage functions in these IAMs are typically calibrated by estimating damages at moderate temperature increases (*e.g.*, DICE was calibrated at 2.5 °C) and extrapolated to far higher temperatures by assuming that damages increase as some power of the temperature change. Hence, estimated damages are far more uncertain under more extreme climate change scenarios.

Incomplete treatment of adaptation and technological change: Each of the three integrated assessment models used here assumes a certain degree of low- or no-cost adaptation. For instance, Tol assumes a great deal of adaptation in FUND, including widespread reliance on air conditioning; so much so, that the largest single benefit category in FUND is the reduced electricity costs from not having to run air conditioning as intensively (NRC 2009).

Climate change also will increase returns on investment to develop technologies that allow individuals to cope with adverse climate conditions, and IAMs to do not adequately account for this directed technological change.[dd] For example, scientists may develop crops that are better able to withstand higher and more variable temperatures. Although DICE and FUND have both calibrated their agricultural sectors under the assumption that farmers will change land use practices in response to climate change (Mastrandrea, 2009), they do not take into account technological changes that lower the cost of this adaptation over time. On the other hand, the calibrations do not account for increases in climate variability, pests, or diseases, which could make adaptation more difficult than assumed by the IAMs for a given temperature change. Hence, models do not adequately account for potential adaptation or technical change that might alter the emissions pathway and resulting damages. In this respect, it is difficult to determine whether the incomplete treatment of adaptation and technological change in these IAMs understate or overstate the likely damages.

Risk aversion: A key question unanswered during this interagency process is what to assume about relative risk aversion with regard to high-impact outcomes. These calculations do not take into account the possibility that individuals may have a higher willingness to pay to reduce the likelihood of low-probability, high-impact damages than they do to reduce the likelihood of higher-probability, but lower-impact, damages with the same expected cost. (The inclusion of the 95th percentile estimate in the final set of SCC values was largely motivated by this concern.) If individuals do show such a higher willingness to pay, a further question is whether that fact should be taken into account for regulatory policy. Even if individuals are not

[dd] However these research dollars will be diverted from whatever their next best use would have been in the absence of climate change (so productivity/GDP would have been still higher).

risk-averse for such scenarios, it is possible that regulatory policy should include a degree of risk-aversion.

Assuming a risk-neutral representative agent is consistent with OMB's Circular A-4, which advises that the estimates of benefits and costs used in regulatory analysis are usually based on the average or the expected value and that "emphasis on these expected values is appropriate as long as society is 'risk neutral' with respect to the regulatory alternatives. While this may not always be the case, [analysts] should in general assume 'risk neutrality' in [their] analysis."

Nordhaus (2008) points to the need to explore the relationship between risk and income in the context of climate change across models and to explore the role of uncertainty regarding various parameters in the results. Using FUND, Anthoff *et al* (2009) explored the sensitivity of the SCC to Ramsey equation parameter assumptions based on observed behavior. They conclude that "the assumed rate of risk aversion is at least as important as the assumed rate of time preference in determining the social cost of carbon." Since Circular A-4 allows for a different assumption on risk preference in regulatory analysis if it is adequately justified, we plan to continue investigating this issue.

14A.7 A FURTHER DISCUSSION OF CATASTROPHIC IMPACTS AND DAMAGE FUNCTIONS

As noted above, the damage functions underlying the three IAMs used to estimate the SCC may not capture the economic effects of all possible adverse consequences of climate change and may therefore lead to underestimates of the SCC (Mastrandrea 2009). In particular, the models' functional forms may not adequately capture: (1) potentially discontinuous "tipping point" behavior in Earth systems, (2) inter-sectoral and inter-regional interactions, including global security impacts of high-end warming, and (3) limited near-term substitutability between damage to natural systems and increased consumption.

It is the hope of the interagency group that over time researchers and modelers will work to fill these gaps and that the SCC estimates used for regulatory analysis by the Federal government will continue to evolve with improvements in modeling. In the meantime, we discuss some of the available evidence.

Extrapolation of climate damages to high levels of warming

The damage functions in the models are calibrated at moderate levels of warming and should therefore be viewed cautiously when extrapolated to the high temperatures found in the upper end of the distribution. Recent science suggests that there are a number of potential climatic "tipping points" at which the Earth system may exhibit discontinuous behavior with potentially severe social and economic consequences (*e.g.*, Lenton *et al*, 2008, Kriegler *et al*., 2009). These tipping points include the disruption of the Indian Summer Monsoon, dieback of

the Amazon Rainforest and boreal forests, collapse of the Greenland Ice Sheet and the West Antarctic Ice Sheet, reorganization of the Atlantic Meridional Overturning Circulation, strengthening of El Niño-Southern Oscillation, and the release of methane from melting permafrost. Many of these tipping points are estimated to have thresholds between about 3 °C and 5 °C (Lenton *et al*., 2008). Probabilities of several of these tipping points were assessed through expert elicitation in 2005–2006 by Kriegler *et al*. (2009); results from this study are highlighted in Table 14A.7.1. Ranges of probability are averaged across core experts on each topic.

As previously mentioned, FUND does not include potentially catastrophic effects. DICE assumes a small probability of catastrophic damages that increases with increased warming, but the damages from these risks are incorporated as expected values (*i.e.*, ignoring potential risk aversion). PAGE models catastrophic impacts in a probabilistic framework (see Figure 14A.4.1), so the high-end output from PAGE potentially offers the best insight into the SCC if the world were to experience catastrophic climate change. For instance, at the 95th percentile and a 3 percent discount rate, the SCC estimated by PAGE across the five socioeconomic and emission trajectories of $113 per ton of CO_2 is almost double the value estimated by DICE, $58 per ton in 2010. We cannot evaluate how well the three models account for catastrophic or non-catastrophic impacts, but this estimate highlights the sensitivity of SCC values in the tails of the distribution to the assumptions made about catastrophic impacts.

Table 14A.7.1 Probabilities of Various Tipping Points from Expert Elicitation

Possible Tipping Points	Duration before effect is fully realized (in years)	Additional Warming by 2100		
		0.5-1.5 C	1.5-3.0 C	3-5 C
Reorganization of Atlantic Meridional Overturning Circulation	about 100	0-18%	6-39%	18-67%
Greenland Ice Sheet collapse	at least 300	8-39%	33-73%	67-96%
West Antarctic Ice Sheet collapse	at least 300	5-41%	10-63%	33-88%
Dieback of Amazon rainforest	about 50	2-46%	14-84%	41-94%
Strengthening of El Niño-Southern Oscillation	about 100	1-13%	6-32%	19-49%
Dieback of boreal forests	about 50	13-43%	20-81%	34-91%
Shift in Indian Summer Monsoon	about 1	Not formally assessed		
Release of methane from melting permafrost	Less than 100	Not formally assessed.		

PAGE treats the possibility of a catastrophic event probabilistically, while DICE treats it deterministically (that is, by adding the expected value of the damage from a catastrophe to the aggregate damage function). In part, this results in different probabilities being assigned to a

catastrophic event across the two models. For instance, PAGE places a probability near zero on a catastrophe at 2.5 °C warming, while DICE assumes a 4 percent probability of a catastrophe at 2.5 °C. By comparison, Kriegler *et al*. (2009) estimate a probability of at least 16-36 percent of crossing at least one of their primary climatic tipping points in a scenario with temperatures about 2-4 °C warmer than pre-Industrial levels in 2100.

It is important to note that crossing a climatic tipping point will not necessarily lead to an economic catastrophe in the sense used in the IAMs. A tipping point is a critical threshold across which some aspect of the Earth system starts to shifts into a qualitatively different state (for instance, one with dramatically reduced ice sheet volumes and higher sea levels). In the IAMs, a catastrophe is a low-probability environmental change with high economic impact.

Failure to incorporate inter-sectoral and inter-regional interactions

The damage functions do not fully incorporate either inter-sectoral or inter-regional interactions. For instance, while damages to the agricultural sector are incorporated, the effects of changes in food supply on human health are not fully captured and depend on the modeler's choice of studies used to calibrate the IAM. Likewise, the effects of climate damages in one region of the world on another region are not included in some of the models (FUND includes the effects of migration from sea level rise). These inter-regional interactions, though difficult to quantify, are the basis for climate-induced national and economic security concerns (*e.g.*, Campbell *et al*., 2007; U.S. Department of Defense 2010) and are particularly worrisome at higher levels of warming. High-end warming scenarios, for instance, project water scarcity affecting 4.3-6.9 billion people by 2050, food scarcity affecting about 120 million additional people by 2080, and the creation of millions of climate refugees (Easterling *et al*., 2007; Campbell *et al*., 2007).

Imperfect substitutability of environmental amenities

Data from the geological record of past climate changes suggests that 6 °C of warming may have severe consequences for natural systems. For instance, during the Paleocene-Eocene Thermal Maximum about 55.5 million years ago, when the Earth experienced a geologically rapid release of carbon associated with an approximately 5 °C increase in global mean temperatures, the effects included shifts of about 400-900 miles in the range of plants (Wing *et al*., 2005), and dwarfing of both land mammals (Gingerich, 2006) and soil fauna (Smith *et al*., 2009).

The three IAMs used here assume that it is possible to compensate for the economic consequences of damages to natural systems through increased consumption of non-climate goods, a common assumption in many economic models. In the context of climate change, however, it is possible that the damages to natural systems could become so great that no increase in consumption of non-climate goods would provide complete compensation (Levy *et al*., 2005). For instance, as water supplies become scarcer or ecosystems become more fragile and less bio-diverse, the services they provide may become increasingly more costly to replace.

Uncalibrated attempts to incorporate the imperfect substitutability of such amenities into IAMs (Sterner and Persson, 2008) indicate that the optimal degree of emissions abatement can be considerably greater than is commonly recognized.

14A.8 CONCLUSION

The interagency group selected four SCC estimates for use in regulatory analyses. For 2010, these estimates are $5, $21, $35, and $65 (in 2007 dollars). The first three estimates are based on the average SCC across models and socioeconomic and emissions scenarios at the 5, 3, and 2.5 percent discount rates, respectively. The fourth value is included to represent the higher-than-expected impacts from temperature change further out in the tails of the SCC distribution. For this purpose, we use the SCC value for the 95th percentile at a 3 percent discount rate. The central value is the average SCC across models at the 3 percent discount rate. For purposes of capturing the uncertainties involved in regulatory impact analysis, we emphasize the importance and value of considering the full range. These SCC estimates also grow over time. For instance, the central value increases to $24 per ton of CO_2 in 2015 and $26 per ton of CO_2 in 2020.

We noted a number of limitations to this analysis, including the incomplete way in which the integrated assessment models capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. The limited amount of research linking climate impacts to economic damages makes this modeling exercise even more difficult. It is the hope of the interagency group that over time researchers and modelers will work to fill these gaps and that the SCC estimates used for regulatory analysis by the Federal government will continue to evolve with improvements in modeling.

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14A.9 ANNEX

Table 14A.9.1 Annual SCC Values: 2010–2050 (in 2007 dollars)

Discount Rate Year	5% Avg	3% Avg	2.5% Avg	3% 95th
2010	4.7	21.4	35.1	64.9
2011	4.9	21.9	35.7	66.5
2012	5.1	22.4	36.4	68.1
2013	5.3	22.8	37.0	69.6
2014	5.5	23.3	37.7	71.2
2015	5.7	23.8	38.4	72.8
2016	5.9	24.3	39.0	74.4
2017	6.1	24.8	39.7	76.0
2018	6.3	25.3	40.4	77.5
2019	6.5	25.8	41.0	79.1
2020	6.8	26.3	41.7	80.7
2021	7.1	27.0	42.5	82.6
2022	7.4	27.6	43.4	84.6
2023	7.7	28.3	44.2	86.5
2024	7.9	28.9	45.0	88.4
2025	8.2	29.6	45.9	90.4
2026	8.5	30.2	46.7	92.3
2027	8.8	30.9	47.5	94.2
2028	9.1	31.5	48.4	96.2
2029	9.4	32.1	49.2	98.1
2030	9.7	32.8	50.0	100.0
2031	10.0	33.4	50.9	102.0
2032	10.3	34.1	51.7	103.9
2033	10.6	34.7	52.5	105.8
2034	10.9	35.4	53.4	107.8
2035	11.2	36.0	54.2	109.7
2036	11.5	36.7	55.0	111.6
2037	11.8	37.3	55.9	113.6
2038	12.1	37.9	56.7	115.5
2039	12.4	38.6	57.5	117.4
2040	12.7	39.2	58.4	119.3
2041	13.0	39.8	59.0	121.0
2042	13.3	40.4	59.7	122.7
2043	13.6	40.9	60.4	124.4
2044	13.9	41.5	61.0	126.1
2045	14.2	42.1	61.7	127.8
2046	14.5	42.6	62.4	129.4
2047	14.8	43.2	63.0	131.1
2048	15.1	43.8	63.7	132.8
2049	15.4	44.4	64.4	134.5
2050	15.7	44.9	65.0	136.2

This Annex provides additional technical information about the non-CO_2 emission projections used in the modeling and the method for extrapolating emissions forecasts through 2300 and shows the full distribution of 2010 SCC estimates by model and scenario combination.

14A.9.1 Other (non-CO_2) gases

In addition to fossil and industrial CO_2 emissions, each EMF scenario provides projections of methane (CH_4), nitrous oxide (N_2O), fluorinated gases, and net land use CO_2 emissions to 2100. These assumptions are used in all three IAMs while retaining each model's default radiative forcings (RF) due to other factors (*e.g.*, aerosols and other gases). Specifically, to obtain the RF associated with the non-CO_2 EMF emissions only, we calculated the RF associated with the EMF atmospheric CO_2 concentrations and subtracted them from the EMF total RF.[ee] This approach respects the EMF scenarios as much as possible and at the same time takes account of those components not included in the EMF projections. Since each model treats non-CO_2 gases differently (*e.g.*, DICE lumps all other gases into one composite exogenous input), this approach was applied slightly differently in each of the models.

FUND: Rather than relying on RF for these gases, the actual emissions from each scenario were used in FUND. The model default trajectories for CH_4, N_20, SF_6, and the CO_2 emissions from land were replaced with the EMF values.

PAGE: PAGE models CO_2, CH_4, sulfur hexafluoride (SF_6), and aerosols and contains an "excess forcing" vector that includes the RF for everything else. To include the EMF values, we removed the default CH_4 and SF_6 factors[ff], decomposed the excess forcing vector, and constructed a new excess forcing vector that includes the EMF RF for CH_4, N_20, and fluorinated gases, as well as the model default values for aerosols and other factors. Net land use CO_2 emissions were added to the fossil and industrial CO_2 emissions pathway.

DICE: DICE presents the greatest challenge because all forcing due to factors other than industrial CO_2 emissions is embedded in an exogenous non-CO_2 RF vector. To decompose this exogenous forcing path into EMF non-CO_2 gases and other gases, we relied on the references in DICE2007 to the Intergovernmental Panel on Climate Change's (IPCC) Fourth Assessment Report (AR4) and the discussion of aerosol forecasts in the IPCC's Third Assessment Report (TAR) and in AR4, as explained below. In DICE2007, Nordhaus assumes that exogenous forcing from all non-CO_2 sources is -0.06 W/m^2 in 2005, as reported in AR4, and increases linearly to 0.3 W/m^2 in 2105, based on GISS projections, and then stays constant after that time.

According to AR4, the RF in 2005 from CH_4, N_20, and halocarbons (approximately similar to the F-gases in the EMF-22 scenarios) was 0.48 + 0.16 + 0.34 = 0.98 W/m^2 and RF from total aerosols was -1.2 W/m^2. Thus, the -.06 W/m^2 non-CO_2 forcing in DICE can be

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[ee] Note EMF did not provide CO_2 concentrations for the IMAGE reference scenario. Thus, for this scenario, we fed the fossil, industrial, and land CO_2 emissions into MAGICC (considered a "neutral arbiter" model, which is tuned to emulate the major global climate models) and the resulting CO_2 concentrations were used. Note also that MERGE assumes a neutral biosphere so net land CO_2 emissions are set to zero for all years for the MERGE Optimistic reference scenario, and for the MERGE component of the average 550 scenario (*i.e.*, we add up the land use emissions from the other three models and divide by 4).

[ff] Both the model default CH_4 emissions and the initial atmospheric CH_4 is set to zero to avoid double counting the effect of past CH_4 emissions.

decomposed into: 0.98 W/m^2 due to the EMF non-CO_2 gases, -1.2 W/m^2 due to aerosols, and the remainder, 0.16 W/m^2, due to other residual forcing.

For subsequent years, we calculated the DICE default RF from aerosols and other non-CO_2 gases based on the following two assumptions:

(1) RF from aerosols declines linearly from 2005 to 2100 at the rate projected by the TAR and then stays constant thereafter; and
(2) With respect to RF from non-CO_2 gases not included in the EMF-22 scenarios, the share of non-aerosol RF matches the share implicit in the AR4 summary statistics cited above and remains constant over time.

Assumption (1) means that the RF from aerosols in 2100 equals 66 percent of that in 2000, which is the fraction of the TAR projection of total RF from aerosols (including sulfates, black carbon, and organic carbon) in 2100 vs. 2000 under the A1B SRES emissions scenario. Since the SRES marker scenarios were not updated for the AR4, the TAR provides the most recent IPCC projection of aerosol forcing. We rely on the A1B projection from the TAR because it provides one of the lower aerosol forecasts among the SRES marker scenarios and is more consistent with the AR4 discussion of the post-SRES literature on aerosols:

Aerosols have a net cooling effect and the representation of aerosol and aerosol precursor emissions, including sulfur dioxide, black carbon and organic carbon, has improved in the post-SRES scenarios. Generally, these emissions are projected to be lower than reported in SRES.[gg]

Assuming a simple linear decline in aerosols from 2000 to 2100 also is more consistent with the recent literature on these emissions. For example, the figure below shows that the sulfur dioxide emissions peak over the short term of some SRES scenarios above the upper bound estimates of the more recent scenarios.[hh] Recent scenarios project sulfur emissions to peak earlier and at lower levels compared to the SRES in part because of new information about present and planned sulfur legislation in some developing countries, such as India and China.[ii] The lower-bound projections of the recent literature have also shifted downward slightly compared to the SRES scenario (IPCC 2007).

With these assumptions, the DICE aerosol forcing changes from -1.2 in 2005 to -0.792 in 2105 W/m^2; forcing due to other non-CO_2 gases not included in the EMF scenarios declines from 0.160 to 0.153 W/m^2.

[gg] AR4 Synthesis Report, p. 44, www.ipcc.ch/pdf/assessment-report/ar4/syr/ar4_syr.pdf
[hh] See Smith, S.J., R. Andres, E. Conception, and J. Lurz, 2004: Historical sulfur dioxide emissions, 1850-2000: methods and results. Joint Global Research Institute, College Park, 14 pp.
[ii] See Carmichael, G., D. Streets, G. Calori, M. Amann, M. Jacobson, J. Hansen, and H. Ueda, 2002: Changing trends in sulphur emissions in Asia: implications for acid deposition, air pollution, and climate. Environmental Science and Technology, 36(22):4707- 4713; Streets, D., K. Jiang, X. Hu, J. Sinton, X.-Q. Zhang, D. Xu, M. Jacobson, and J. Hansen, 2001: Recent reductions in China's greenhouse gas emissions. Science, 294(5548): 1835-1837.

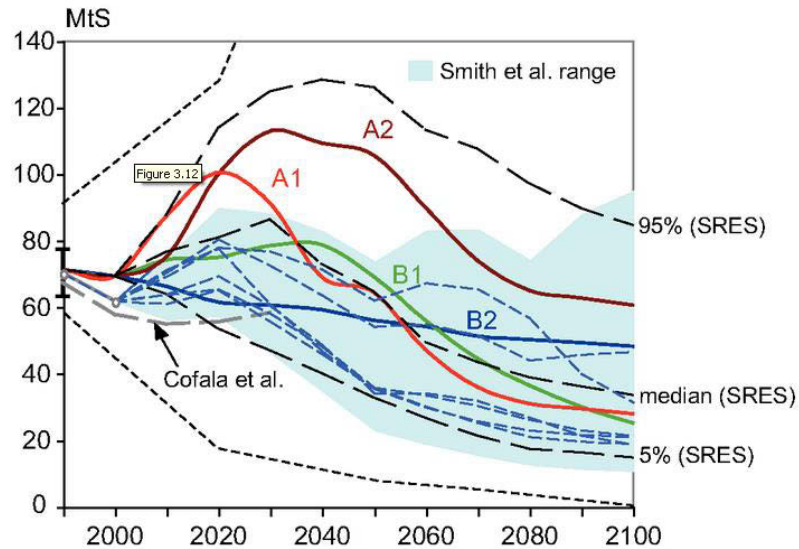

Figure 14A.9.2 Sulfur Dioxide Emission Scenarios

Notes: Thick colored lines depict the four SRES marker scenarios and black dashed lines show the median, 5th, and 95th percentile of the frequency distribution for the full ensemble of 40 SRES scenarios. The blue area (and the thin dashed lines in blue) illustrates individual scenarios and the range of Smith *et al*. (2004). Dotted lines indicate the minimum and maximum of SO_2 emissions scenarios developed pre-SRES.
Source: IPCC (2007), AR4 WGIII 3.2, www.ipcc.ch/publications_and_data/ar4/wg3/en/ch3-ens3-2-2-4.html.

Although other approaches to decomposing the DICE exogenous forcing vector are possible, initial sensitivity analysis suggests that the differences among reasonable alternative approaches are likely to be minor. For example, adjusting the TAR aerosol projection above to assume that aerosols will be maintained at 2000 levels through 2100 reduces average SCC values (for 2010) by approximately 3 percent (or less than $2); assuming all aerosols are phased out by 2100 increases average 2010 SCC values by 6-7 percent (or $0.50-$3)–depending on the discount rate. These differences increase slightly for SCC values in later years but are still well within 10 percent of each other as far out as 2050.

Finally, as in PAGE, the EMF net land use CO_2 emissions are added to the fossil and industrial CO_2 emissions pathway.

14A.9.2 Extrapolating Emissions Projections to 2300

To run each model through 2300 requires assumptions about GDP, population, greenhouse gas emissions, and radiative forcing trajectories after 2100, the last year for which these projections are available from the EMF-22 models. These inputs were extrapolated from 2100 to 2300 as follows:

1. Population growth rate declines linearly, reaching zero in the year 2200.
2. GDP/per capita growth rate declines linearly, reaching zero in the year 2300.
3. The decline in the fossil and industrial carbon intensity (CO_2/GDP) growth rate over 2090-2100 is maintained from 2100 through 2300.
4. Net land use CO_2 emissions decline linearly, reaching zero in the year 2200.
5. Non-CO_2 radiative forcing remains constant after 2100.

Long run stabilization of GDP per capita was viewed as a more realistic simplifying assumption than a linear or exponential extrapolation of the pre-2100 economic growth rate of each EMF scenario. This is based on the idea that increasing scarcity of natural resources and the degradation of environmental sinks available for assimilating pollution from economic production activities may eventually overtake the rate of technological progress. Thus, the overall rate of economic growth may slow over the very long run. The interagency group also considered allowing an exponential decline in the growth rate of GDP per capita. However, since this would require an additional assumption about how close to zero the growth rate would get by 2300, the group opted for the simpler and more transparent linear extrapolation to zero by 2300.

The population growth rate is also assumed to decline linearly, reaching zero by 2200. This assumption is reasonably consistent with the United Nations long run population forecast, which estimates global population to be fairly stable after 2150 in the medium scenario (UN 2004).[jj] The resulting range of EMF population trajectories (figure below) also encompass the UN medium scenario forecasts through 2300—global population of 8.5 billion by 2200, and 9 billion by 2300.

Maintaining the decline in the 2090-2100 carbon intensity growth rate (*i.e.*, CO_2 per dollar of GDP) through 2300 assumes that technological improvements and innovations in the areas of energy efficiency and other carbon reducing technologies (possibly including currently unavailable methods) will continue to proceed at roughly the same pace that is projected to occur towards the end of the forecast period for each EMF scenario. This assumption implies that total cumulative emissions in 2300 will be between 5,000 and 12,000 GtC, which is within the range of the total potential global carbon stock estimated in the literature.

Net land use CO_2 emissions are expected to stabilize in the long run, so in the absence of any post 2100 projections, the group assumed a linear decline to zero by 2200. Given no a priori reasons for assuming a long run increase or decline in non-CO_2 radiative forcing, it is assumed to remain at the 2100 levels for each EMF scenario through 2300.

Figures below show the paths of global population, GDP, fossil and industrial CO_2 emissions, net land CO_2 emissions, non-CO_2 radiative forcing, and CO_2 intensity (fossil and industrial CO_2 emissions/GDP) resulting from these assumptions.

[jj] United Nations. 2004. *World Population to 2300*. www.un.org/esa/population/publications/longrange2/WorldPop2300final.pdf

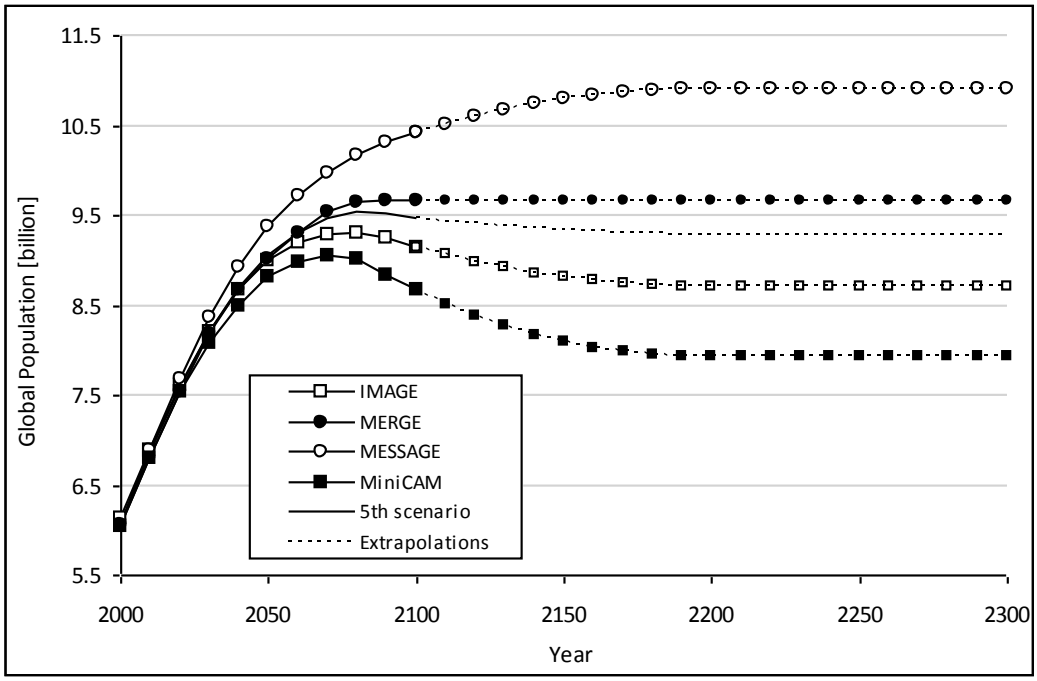

Figure 14A.9.3 Global Population, 2000-2300 (Post-2100 extrapolations assume the population growth rate changes linearly to reach a zero growth rate by 2200.)

Note: In the fifth scenario, 2000-2100 population is equal to the average of the population under the 550 ppm CO_2e, full-participation, not-to-exceed scenarios considered by each of the four models.

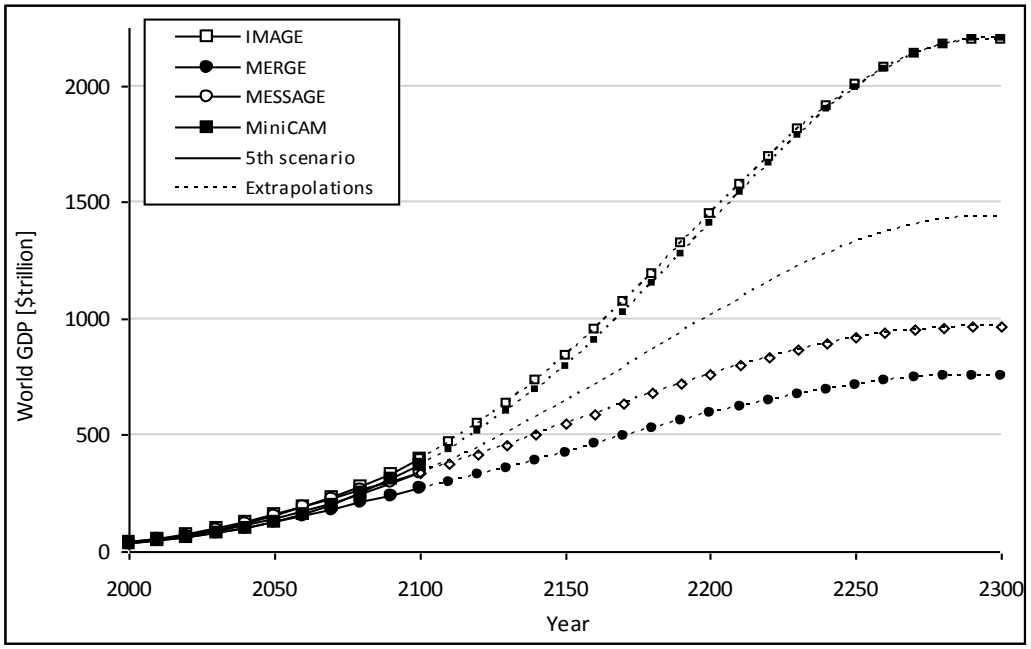

Figure 14A.9.4 World GDP, 2000-2300 (Post-2100 extrapolations assume GDP per capita growth declines linearly, reaching zero in the year 2300)

Note: In the fifth scenario, 2000-2100 GDP is equal to the average of the GDP under the 550 ppm CO_2e, full-participation, not-to-exceed scenarios considered by each of the four models.

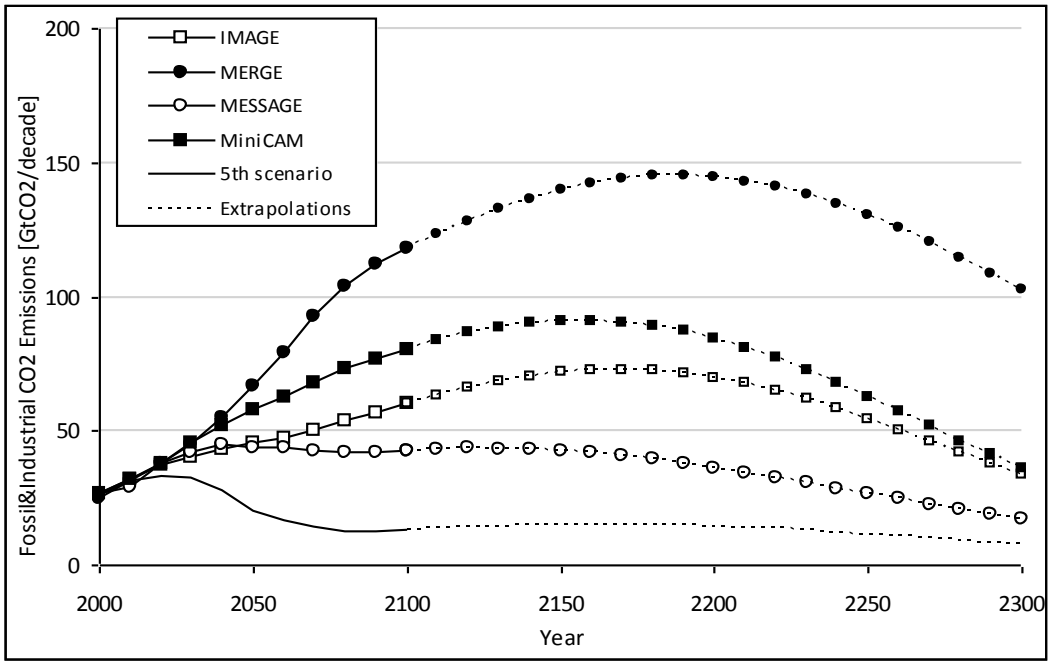

Figure 14A.9.5 Global Fossil and Industrial CO_2 Emissions, 2000-2300 (Post-2100 extrapolations assume growth rate of CO_2 intensity (CO_2/GDP) over 2090-2100 is maintained through 2300)

Note: In the fifth scenario, 2000-2100 emissions are equal to the average of the emissions under the 550 ppm CO_2e, full-participation, not-to-exceed scenarios considered by each of the four models.

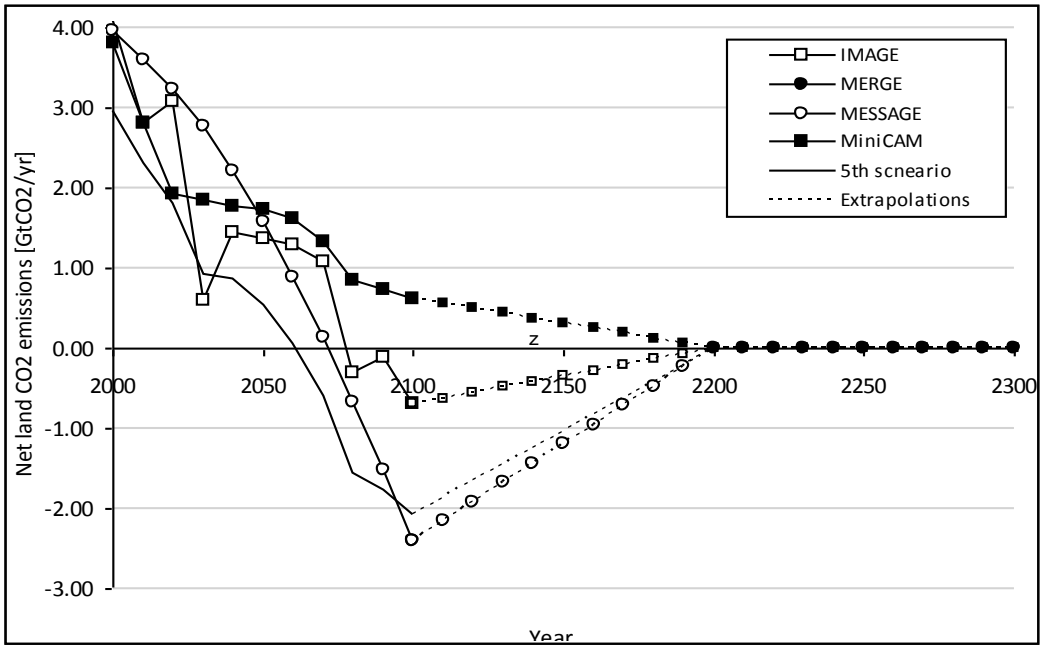

Figure 14A.9.6 Global Net Land Use CO_2 Emissions, 2000-2300 (Post-2100 extrapolations assume emissions decline linearly, reaching zero in the year 2200)[kk]

Note: In the fifth scenario, 2000-2100 emissions are equal to the average of the emissions under the 550 ppm CO_2e, full-participation, not-to-exceed scenarios considered by each of the four models.

[kk] MERGE assumes a neutral biosphere so net land CO_2 emissions are set to zero for all years for the MERGE Optimistic reference scenario, and for the MERGE component of the average 550 scenario (*i.e.*, we add up the land use emissions from the other three models and divide by 4).

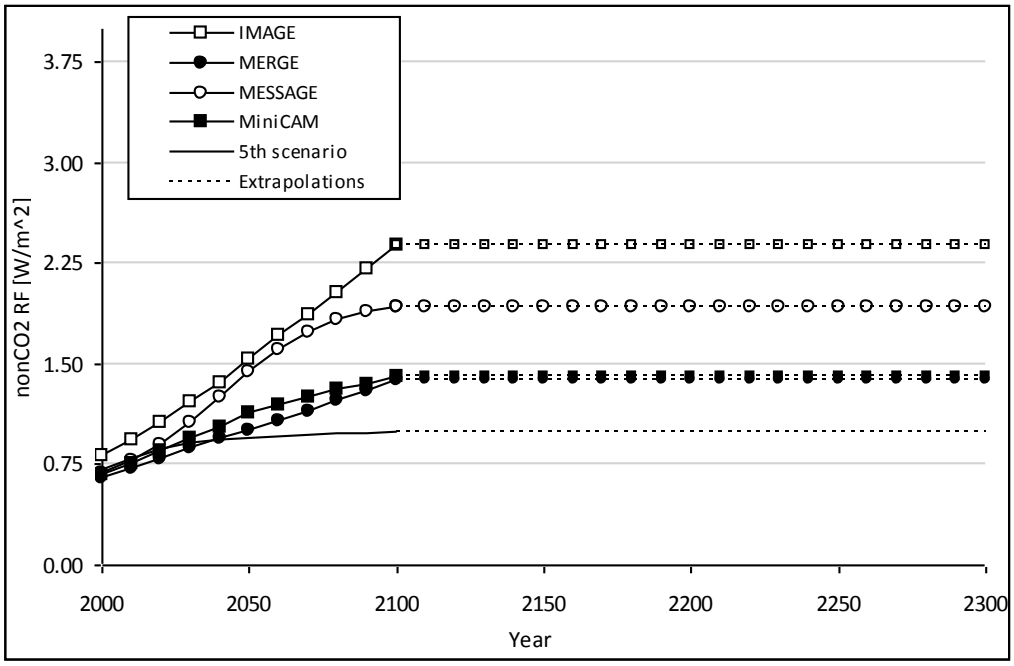

Figure 14A.9.7 Global Non-CO_2 Radiative Forcing, 2000-2300 (Post-2100 extrapolations assume constant non-CO_2 radiative forcing after 2100)

Note: In the fifth scenario, 2000-2100 emissions are equal to the average of the emissions under the 550 ppm CO_2e, full-participation, not-to-exceed scenarios considered by each of the four models.

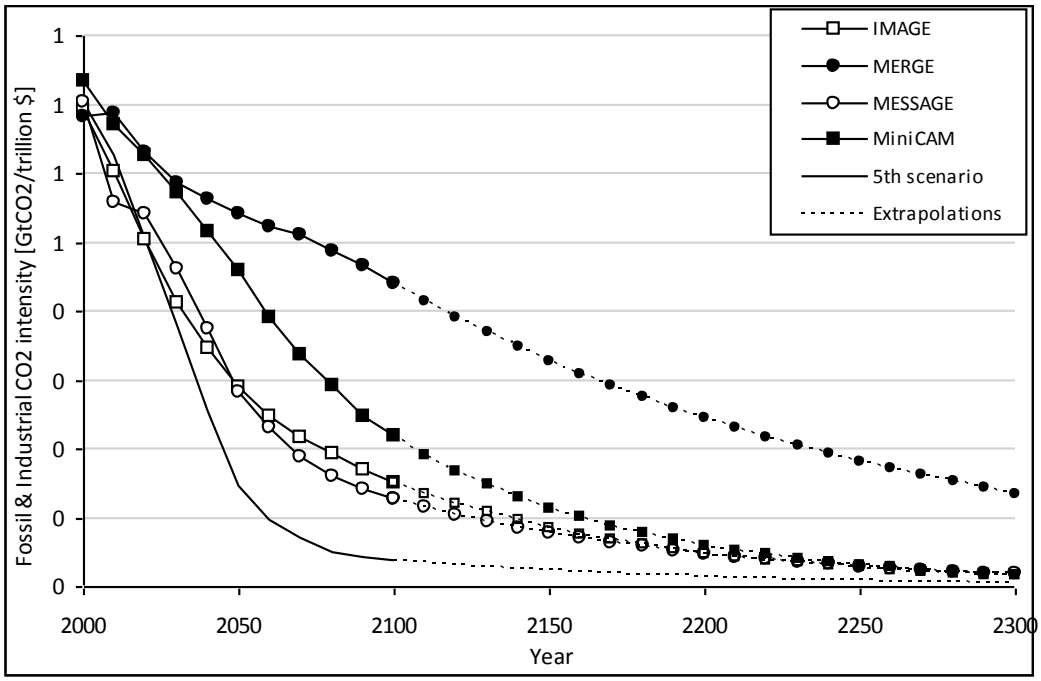

Figure 14A.9.8 Global CO_2 Intensity (fossil & industrial CO_2 emissions/GDP), 2000-2300 (Post-2100 extrapolations assume decline in CO_2/GDP growth rate over 2090-2100 is maintained through 2300)

Note: In the fifth scenario, 2000-2100 emissions are equal to the average of the emissions under the 550 ppm CO_2e, full-participation, not-to-exceed scenarios considered by each of the four models.

Table 14A.9.2 2010 Global SCC Estimates at 2.5 Percent Discount Rate (2007$/ton CO_2)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95th	99th
Scenario					**PAGE**					
IMAGE	3.3	5.9	8.1	13.9	28.8	65.5	68.2	147.9	239.6	563.8
MERGE optimistic	1.9	3.2	4.3	7.2	14.6	34.6	36.2	79.8	124.8	288.3
Message	2.4	4.3	5.8	9.8	20.3	49.2	50.7	114.9	181.7	428.4
MiniCAM base	2.7	4.6	6.4	11.2	22.8	54.7	55.7	120.5	195.3	482.3
5th scenario	2.0	3.5	4.7	8.1	16.3	42.9	41.5	103.9	176.3	371.9
Scenario					**DICE**					
IMAGE	16.4	21.4	25	33.3	46.8	54.2	69.7	96.3	111.1	130.0
MERGE optimistic	9.7	12.6	14.9	19.7	27.9	31.6	40.7	54.5	63.5	73.3
Message	13.5	17.2	20.1	27	38.5	43.5	55.1	75.8	87.9	103.0
MiniCAM base	13.1	16.7	19.8	26.7	38.6	44.4	56.8	79.5	92.8	109.3
5th scenario	10.8	14	16.7	22.2	32	37.4	47.7	67.8	80.2	96.8
Scenario					**FUND**					
IMAGE	-33.1	-18.9	-13.3	-5.5	4.1	19.3	18.7	43.5	67.1	150.7
MERGE optimistic	-33.1	-14.8	-10	-3	5.9	14.8	20.4	43.9	65.4	132.9
Message	-32.5	-19.8	-14.6	-7.2	1.5	8.8	13.8	33.7	52.3	119.2
MiniCAM base	-31.0	-15.9	-10.7	-3.4	6	22.2	21	46.4	70.4	152.9
5th scenario	-32.2	-21.6	-16.7	-9.7	-2.3	3	6.7	20.5	34.2	96.8

Table 14A.9.3 2010 Global SCC Estimates at 3 Percent Discount Rate (2007$/ton CO_2)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95th	99th
Scenario					**PAGE**					
IMAGE	2.0	3.5	4.8	8.1	16.5	39.5	41.6	90.3	142.4	327.4
MERGE optimistic	1.2	2.1	2.8	4.6	9.3	22.3	22.8	51.3	82.4	190.0
Message	1.6	2.7	3.6	6.2	12.5	30.3	31	71.4	115.6	263.0
MiniCAM base	1.7	2.8	3.8	6.5	13.2	31.8	32.4	72.6	115.4	287.0
5th scenario	1.3	2.3	3.1	5	9.6	25.4	23.6	62.1	104.7	222.5
Scenario					**DICE**					
IMAGE	11.0	14.5	17.2	22.8	31.6	35.8	45.4	61.9	70.8	82.1
MERGE optimistic	7.1	9.2	10.8	14.3	19.9	22	27.9	36.9	42.1	48.8
Message	9.7	12.5	14.7	19	26.6	29.8	37.8	51.1	58.6	67.4
MiniCAM base	8.8	11.5	13.6	18	25.2	28.8	36.9	50.4	57.9	67.8
5th scenario	7.9	10.1	11.8	15.6	21.6	24.9	31.8	43.7	50.8	60.6
Scenario					**FUND**					
IMAGE	-25.2	-15.3	-11.2	-5.6	0.9	8.2	10.4	25.4	39.7	90.3
MERGE optimistic	-24.0	-12.4	-8.7	-3.6	2.6	8	12.2	27	41.3	85.3
Message	-25.3	-16.2	-12.2	-6.8	-0.5	3.6	7.7	20.1	32.1	72.5
MiniCAM base	-23.1	-12.9	-9.3	-4	2.4	10.2	12.2	27.7	42.6	93.0
5th scenario	-24.1	-16.6	-13.2	-8.3	-3	-0.2	2.9	11.2	19.4	53.6

Table 14A.9.4 2010 Global SCC Estimates at 5 Percent Discount Rate (2007$/ton CO_2)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95th	99th
Scenario					**PAGE**					
IMAGE	0.5	0.8	1.1	1.8	3.5	8.3	8.5	19.5	31.4	67.2
MERGE optimistic	0.3	0.5	0.7	1.2	2.3	5.2	5.4	12.3	19.5	42.4
Message	0.4	0.7	0.9	1.6	3	7.2	7.2	17	28.2	60.8
MiniCAM base	0.3	0.6	0.8	1.4	2.7	6.4	6.6	15.9	24.9	52.6
5th scenario	0.3	0.6	0.8	1.3	2.3	5.5	5	12.9	22	48.7
Scenario					**DICE**					
IMAGE	4.2	5.4	6.2	7.6	10	10.8	13.4	16.8	18.7	21.1
MERGE optimistic	2.9	3.7	4.2	5.3	7	7.5	9.3	11.7	12.9	14.4
Message	3.9	4.9	5.5	7	9.2	9.8	12.2	15.4	17.1	18.8
MiniCAM base	3.4	4.2	4.7	6	7.9	8.6	10.7	13.5	15.1	16.9
5th scenario	3.2	4	4.6	5.7	7.6	8.2	10.2	12.8	14.3	16.0
Scenario					**FUND**					
IMAGE	-11.7	-8.4	-6.9	-4.6	-2.2	-1.3	0.7	4.1	7.4	17.4
MERGE optimistic	-10.6	-7.1	-5.6	-3.6	-1.3	-0.3	1.6	5.4	9.1	19.0
Message	-12.2	-8.9	-7.3	-4.9	-2.5	-1.9	0.3	3.5	6.5	15.6
MiniCAM base	-10.4	-7.2	-5.8	-3.8	-1.5	-0.6	1.3	4.8	8.2	18.0
5th scenario	-10.9	-8.3	-7	-5	-2.9	-2.7	-0.8	1.4	3.2	9.2

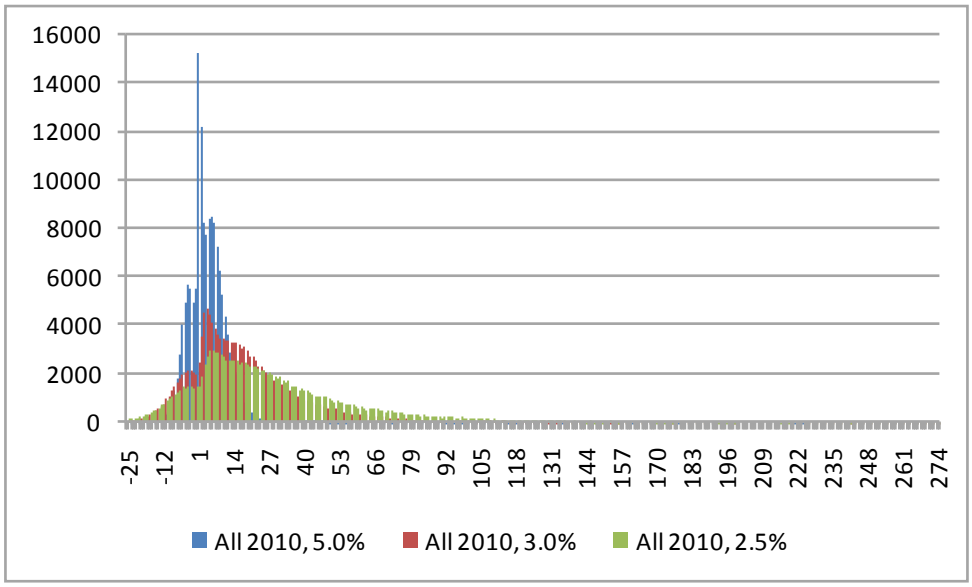

Figure 14A.9.9 Histogram of Global SCC Estimates in 2010 (2007$/ton CO_2), by discount rate*

* The distribution of SCC values ranges from -$5,192 to $66,116, but the X-axis has been truncated at approximately the 1st and 99th percentiles to better show the data.

Table 14A.9.5 Additional Summary Statistics of 2010 Global SCC Estimates

Discount Rate		Scenario		
		DICE	**PAGE**	**FUND**
5%	Mean	9	6.5	-1.3
	Variance	13.1	136	70.1
	Skewness	0.8	6.3	28.2
	Kurtosis	0.2	72.4	1,479.00
3%	Mean	28.3	29.8	6
	Variance	209.8	3,383.70	16,382.50
	Skewness	1.1	8.6	128
	Kurtosis	0.9	151	18,976.50
2.50%	Mean	42.2	49.3	13.6
	Variance	534.9	9,546.00	#######
	Skewness	1.2	8.7	149
	Kurtosis	1.1	143.8	23,558.30

APPENDIX 14B. TECHNICAL UPDATE OF SOCIAL COST OF CARBON FOR REGULATORY IMPACT ANALYSIS UNDER EXECUTIVE ORDER 12866

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APPENDIX 14B. TECHNICAL UPDATE OF SOCIAL COST OF CARBON FOR REGULATORY IMPACT ANALYSIS UNDER EXECUTIVE ORDER 12866

14B.1 PREFACE

The following text is reproduced almost verbatim from the May 2013 report (revised July 2015) of the Interagency Working Group on the Social Cost of Carbon of the United States Government. Minor changes were made to the report's format to make it more consistent with the rest of this technical support document.

14B.2 EXECUTIVE SUMMARY

Under Executive Order 12866, agencies are required, to the extent permitted by law, "to assess the costs and the benefits of the intended regulation and, recognizing that some costs and benefits are difficult to quantify, propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs." The purpose of the "social cost of carbon" (SCC) estimates presented here is to allow agencies to incorporate the social benefits of reducing carbon dioxide (CO_2) emissions into cost-benefit analyses of regulatory actions that impact cumulative global emissions. The SCC is an estimate of the monetized damages associated with an incremental increase in carbon emissions in a given year. It is intended to include (but is not limited to) changes in net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change.

The interagency process that developed the original U.S. government's SCC estimates is described in the 2010 interagency technical support document (TSD) (Interagency Working Group on Social Cost of Carbon 2010). Through that process the interagency group selected four SCC values for use in regulatory analyses. Three values are based on the average SCC from three integrated assessment models (IAMs), at discount rates of 2.5, 3, and 5 percent. The fourth value, which represents the 95th percentile SCC estimate across all three models at a 3 percent discount rate, is included to represent higher-than-expected impacts from temperature change further out in the tails of the SCC distribution.

While acknowledging the continued limitations of the approach taken by the interagency group in 2010, this document provides an update of the SCC estimates based on new versions of each IAM (DICE, PAGE, and FUND). It does not revisit other interagency modeling decisions (e.g., with regard to the discount rate, reference case socioeconomic and emission scenarios, or equilibrium climate sensitivity). Improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves in the peer-reviewed literature.

The SCC estimates using the updated versions of the models are higher than those reported in the 2010 TSD. By way of comparison, the four 2020 SCC estimates reported in the 2010 TSD were $7, $26, $42 and $81 (2007$). The corresponding four updated SCC estimates for 2020 are $12, $43, $64, and $128 (2007$). The model updates that are relevant to the SCC estimates include: an explicit representation of sea level rise damages in the DICE and PAGE

models; updated adaptation assumptions, revisions to ensure damages are constrained by GDP, updated regional scaling of damages, and a revised treatment of potentially abrupt shifts in climate damages in the PAGE model; an updated carbon cycle in the DICE model; and updated damage functions for sea level rise impacts, the agricultural sector, and reduced space heating requirements, as well as changes to the transient response of temperature to the buildup of GHG concentrations and the inclusion of indirect effects of methane emissions in the FUND model. The SCC estimates vary by year, and the following table summarizes the revised SCC estimates from 2010 through 2050.

Table 14B.2.1 Revised Social Cost of CO_2, 2010 – 2050 (in 2007 dollars per ton of CO_2)

Discount Rate Year	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010	10	31	50	86
2015	11	36	56	105
2020	12	42	62	123
2025	14	46	68	138
2030	16	50	73	152
2035	18	55	78	168
2040	21	60	84	183
2045	23	64	89	197
2050	26	69	95	212

14B.3 PURPOSE

The purpose of this document is to update the schedule of social cost of carbon (SCC) [a] estimates from the 2010 interagency technical support document (TSD) (Interagency Working Group on Social Cost of Carbon 2010).[1] E.O. 13563 commits the Administration to regulatory decision making "based on the best available science."[b] Additionally, the interagency group recommended in 2010 that the SCC estimates be revisited on a regular basis or as model updates that reflect the growing body of scientific and economic knowledge become available.[c] New versions of the three integrated assessment models used by the U.S. government to estimate the SCC (DICE, FUND, and PAGE), are now available and have been published in the peer reviewed literature. While acknowledging the continued limitations of the approach taken by the interagency group in 2010 (documented in the original 2010 TSD), this document provides an update of the SCC estimates based solely on the latest peer-reviewed version of the models, replacing model versions that were developed up to ten years ago in a rapidly evolving field. It does not revisit other assumptions with regard to the discount rate, reference case socioeconomic and emission scenarios, or equilibrium climate sensitivity. Improvements in the way damages are modeled are confined to those that have been incorporated into the latest versions of the models by the developers themselves in the peer-reviewed literature. The Environmental Protection Agency (EPA), in collaboration with other Federal agencies such as the Department of Energy

[a] In this document, we present all values of the SCC as the cost per metric ton of CO_2 emissions. Alternatively, one could report the SCC as the cost per metric ton of carbon emissions. The multiplier for translating between mass of CO_2 and the mass of carbon is 3.67.

[b] www.gpo.gov/fdsys/pkg/FR-2011-01-21/pdf/2011-1385.pdf

[c] See p. 1, 3, 4, 29, and 33 (Interagency Working Group on Social Cost of Carbon 2010).[1]

(DOE), continues to investigate potential improvements to the way in which economic damages associated with changes in CO_2 emissions are quantified.

Section 14B.4 summarizes the major updates relevant to SCC estimation that are contained in the new versions of the integrated assessment models released since the 2010 interagency report. Section 14B.5 presents the updated schedule of SCC estimates for 2010 – 2050 based on these versions of the models.

14B.4 SUMMARY OF MODEL UPDATES

This section briefly summarizes changes integrated into the most recent versions of the three integrated assessment models (IAMs) used by the interagency group in 2010. We focus on describing those model updates that are relevant to estimating the social cost of carbon. For example, both the DICE and PAGE models now include an explicit representation of sea level rise damages. Other revisions to PAGE include: updated adaptation assumptions, revisions to ensure damages are constrained GDP, updated regional scaling of damages, and a revised treatment of potentially abrupt shifts in climate damages. In the most recent version of DICE, the model's simple carbon cycle has been updated to be more consistent with a relatively more complex climate model. The FUND model includes updated damage functions for sea level rise impacts, the agricultural sector, and reduced space heating requirements, as well as changes to the response of temperature to the buildup of GHG concentrations and the inclusion of indirect effects of methane emissions. Changes made to parts of the models that are superseded by the interagency working group's modeling assumptions – regarding climate sensitivity, discounting, and socioeconomic variables – are not discussed.

Table 14B.4.1 Summary of Key Model Revisions Relevant to the Interagency SCC

IAM	Version used in 2010 Interagency Analysis	New Version	Key changes relevant to interagency SCC
DICE	2007	2010	Updated calibration of the carbon cycle model and explicit representation of seal level rise (SLR) and associated damages.
FUND	3.5 (2009)	3.8 (2012)	Updated damage functions for space heating, SLR, agricultural impacts, changes to transient response of temperature to buildup of GHG concentrations, and inclusion of indirect climate effects of methane.
PAGE	2002	2009	Explicit representation of SLR damages, revisions to damage function to ensure damages do not exceed 100% of GDP, change in regional scaling of damages, revised treatment of potential abrupt damages, and updated adaptation assumptions.

14B.4.1 DICE

Changes in the DICE model relevant for the SCC estimates developed by the interagency working group include: 1) updated parameter values for the carbon cycle model, 2) an explicit

representation of sea level dynamics, and 3) a re-calibrated damage function that includes an explicit representation of economic damages from sea level rise. Changes were also made to other parts of the DICE model—including the equilibrium climate sensitivity parameter, the rate of change of total factor productivity, and the elasticity of the marginal utility of consumption—but these components of DICE are superseded by the interagency working group's assumptions and so will not be discussed here. More details on DICE2007 can be found in Nordhaus (2008)[2] and on DICE2010 in Nordhaus (2010)[3] and the associated on-line appendix containing supplemental information.

14B.4.1.1 Carbon Cycle Parameters

DICE uses a three-box model of carbon stocks and flows to represent the accumulation and transfer of carbon among the atmosphere, the shallow ocean and terrestrial biosphere, and the deep ocean. These parameters are "calibrated to match the carbon cycle in the Model for the Assessment of Greenhouse Gas Induced Climate Change (MAGICC)" (Nordhaus 2008 p 44).[2d] Carbon cycle transfer coefficient values in DICE2010 are based on re-calibration of the model to match the newer version of MAGICC (Nordhaus 2010 p 2).[3] For example, in DICE2010 in each decade, 12 percent of the carbon in the atmosphere is transferred to the shallow ocean, 4.7 percent of the carbon in the shallow ocean is transferred to the atmosphere, 94.8 percent remains in the shallow ocean, and 0.5 percent is transferred to the deep ocean. For comparison, in DICE 2007, 18.9 percent of the carbon in the atmosphere is transferred to the shallow ocean each decade, 9.7 percent of the carbon in the shallow ocean is transferred to the atmosphere, 85.3 percent remains in the shallow ocean, and 5 percent is transferred to the deep ocean.

The implication of these changes for DICE2010 is in general a weakening of the ocean as a carbon sink and therefore a higher concentration of carbon in the atmosphere than in DICE2007, for a given path of emissions. All else equal, these changes will generally increase the level of warming and therefore the SCC estimates in DICE2010 relative to those from DICE2007.

14B.4.1.2 Sea Level Dynamics

A new feature of DICE2010 is an explicit representation of the dynamics of the global average sea level anomaly to be used in the updated damage function (discussed below). This section contains a brief description of the sea level rise (SLR) module; a more detailed description can be found on the model developer's website.[e] The average global sea level anomaly is modeled as the sum of four terms that represent contributions from: 1) thermal expansion of the oceans, 2) melting of glaciers and small ice caps, 3) melting of the Greenland ice sheet, and 4) melting of the Antarctic ice sheet.

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[d] MAGICC is a simple climate model initially developed within the U.S. National Center for Atmospheric Research that has been used heavily by the Intergovernmental Panel on Climate Change (IPCC) to emulate projections from much more sophisticated state of the art earth system simulation models (Randall et al. 2007).[4]

[e] Documentation on the new sea level rise module of DICE is available on William Nordhaus' website at: www.econ.yale.edu/~nordhaus/homepage/documents/SLR_021910.pdf.

The parameters of the four components of the SLR module are calibrated to match consensus results from the IPCC's Fourth Assessment Report.[4,f] The rise in sea level from thermal expansion in each time period (decade) is 2 percent of the difference between the sea level in the previous period and the long run equilibrium sea level, which is 0.5 meters per degree Celsius (°C) above the average global temperature in 1900. The rise in sea level from the melting of glaciers and small ice caps occurs at a rate of 0.008 meters per decade per °C above the average global temperature in 1900.

The contribution to sea level rise from melting of the Greenland ice sheet is more complex. The equilibrium contribution to SLR is 0 meters for temperature anomalies less than 1 ºC and increases linearly from 0 meters to a maximum of 7.3 meters. The contribution to SLR in each period is proportional to the difference between the previous period's sea level anomaly and the equilibrium sea level anomaly, where the constant of proportionality increases with the temperature anomaly in the current period.

The contribution to SLR from the melting of the Antarctic ice sheet is -0.001 meters per decade when the temperature anomaly is below 3 °C and increases linearly to a maximum rate of 0.025 meters per decade at a temperature anomaly of 6 °C.

14B.4.1.3 Re-calibrated Damage Function

Economic damages from climate change in the DICE model are represented by a fractional loss of gross economic output in each period. A portion of the remaining economic output in each period (net of climate change damages) is consumed and the remainder is invested in the physical capital stock to support future production, so each period's climate damages will reduce consumption in that period and in all future periods due to the lost investment. The fraction of output in each period that is lost due to climate change impacts is represented as one minus a fraction, which is one divided by a quadratic function of the temperature anomaly, producing a sigmoid ("S"-shaped) function. The loss function in DICE2010 has been expanded by adding a quadratic function of SLR to the quadratic function of temperature. In DICE2010 the temperature anomaly coefficients have been recalibrated to avoid double-counting damages from sea level rise that were implicitly included in these parameters in DICE2007.

The aggregate damages in DICE2010 are illustrated by Nordhaus (2010 p 3),[3] who notes that "…damages in the uncontrolled (baseline) (*i.e.*, reference) case … in 2095 are $12 trillion, or 2.8 percent of global output, for a global temperature increase of 3.4 ºC above 1900 levels." This compares to a loss of 3.2 percent of global output at 3.4 ºC in DICE2007. However, in DICE2010 (as downloaded from the homepage of William Nordhaus), annual damages are lower in most of the early periods but higher in later periods of the time horizon than would be calculated using the DICE2007 damage function. Specifically, the percent difference between damages in the base run of DICE2010 and those that would be calculated using the DICE2007 damage function starts at +7 percent in 2005, decreases to a low of -14 percent in 2065, then continuously increases to +20 percent by 2300 (the end of the interagency analysis time horizon), and to +160 percent by the end of the model time horizon in 2595. The large increases in the far

[f] For a review of post-IPCC AR4 research on sea level rise, see Nicholls et al. (2011)[5] and NAS (2011).[6]

future years of the time horizon are due to the permanence associated with damages from sea level rise, along with the assumption that the sea level is projected to continue to rise long after the global average temperature begins to decrease. The changes to the loss function generally decrease the interagency working group SCC estimates slightly, all else equal.

14B.4.2 FUND

FUND version 3.8 includes a number of changes over the previous version 3.5 used in the interagency report. Documentation supporting FUND and the model's source code for all versions of the model is available from the model authors.[g] Notable changes, due to their impact on the estimates of expected SCC, are adjustments to the space heating, agriculture, and sea level rise damage functions in addition to changes to the temperature response function and the inclusion of indirect effects from methane emissions.[h] We discuss each of these in turn.

14B.4.2.1 Space Heating

In FUND, the damages associated with the change in energy needs for space heating are based on the estimated impact due to one degree of warming. These baseline damages are scaled based on the forecasted temperature anomaly's deviation from the one degree benchmark and adjusted for changes in vulnerability due to economic and energy efficiency growth. In FUND 3.5, the function that scales the base year damages adjusted for vulnerability allows for the possibility that in some simulations the benefits associated with reduced heating needs may be an unbounded convex function of the temperature anomaly. In FUND 3.8, the form of the scaling has been modified to ensure that the function is everywhere concave, meaning that for every simulation there will exist an upper bound on the benefits a region may receive from reduced space heating needs. The new formulation approaches a value of two in the limit as the temperature anomaly increases, or in other words, assuming no decrease in vulnerability, the reduced expenditures on space heating at any level of warming will not exceed two times the reductions experienced at one degree of warming. Since the reduced need for space heating represents a benefit of climate change in the model, or a negative damage, this change will increase the estimated SCC. This update accounts for a significant portion of the difference in the expected SCC estimates reported by the two versions of the model when run probabilistically.

14B.4.2.2 Sea Level Rise and Land Loss

The FUND model explicitly includes damages associated with the inundation of dry land due to sea level rise. The amount of land lost within a region is dependent upon the proportion of the coastline being protected by adequate sea walls and the amount of sea level rise. In FUND 3.5 the function defining the potential land lost in a given year due to sea level rise is linear in the rate of sea level rise for that year. This assumption implicitly assumes that all regions are well represented by a homogeneous coastline in length and a constant uniform slope moving

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[g] www.fund-model.org/. This report uses version 3.8 of the FUND model, which represents a modest update to the most recent version of the model to appear in the literature (version 3.7) (Anthoff and Tol, 2013).[7] For the purpose of computing the SCC, the relevant changes are associated with improving consistency with IPCC AR4 by adjusting the atmospheric lifetimes of CH4 and N2O and incorporating the indirect forcing effects of CH4, along with making minor stability improvements in the sea wall construction algorithm.

[h] The other damage sectors (water resources, space cooling, land loss, migration, ecosystems, human health, and extreme weather) were not the subject of significant updates.

inland. In FUND 3.8 the function defining the potential land lost has been changed to be a non-linear function of sea level rise, thereby assuming that the slope of the shore line is not constant moving inland, with a positive first derivative. The effect of this change is to typically reduce the vulnerability of some regions to sea level rise based land loss, therefore having an effect of lowering the expected SCC estimate. The model has also been updated to assume that the value of dry land at risk of inundation is not uniform across a region but will be a decreasing function of protection measure, thereby implicitly assuming that the most valuable land will be protected first.

14B.4.2.3 Agriculture

In FUND, the damages associated with the agricultural sector are measured as proportional to the sector's value. The fraction is made up of three additively separable components that represent the effects from carbon fertilization, the rate of temperature change, and the level of the temperature anomaly. In both FUND 3.5 and FUND 3.8, the fraction of the sector's value lost due to the level of the temperature anomaly is modeled as a quadratic function with an intercept of zero. In FUND 3.5, the linear and quadratic coefficients are modeled as the ratio of two normal distributions. Within this specification, as draws from the distribution in the denominator approached zero the share of the sector's value "lost" approaches (+/-) infinity independent of the temperature anomaly itself. In FUND 3.8, the linear and quadratic coefficients are drawn directly from truncated normal distributions so that they remain in the range $[0,\infty)$ and $(-\infty,0]$, respectively, where the means for the new distributions are set equal to the ratio of the means from the normal distributions used in the previous version. In general the impact of this change has been to increase the likelihood that increases in the temperature level will have either larger positive or negative effects on the agricultural sector relative to the previous version (through eliminating simulations in which the "lost" value approached (+/-) infinity). The net effect of this change on the SCC estimates is difficult to predict.

14B.4.2.4 Temperature Response Model

The temperature response model translates changes in global levels of radiative forcing into the current expected temperature anomaly. In FUND, a given year's increase in the cumulative temperature anomaly is based on a mean reverting function where the mean equals the equilibrium temperature anomaly that would eventually be reached if that year's level of radiative forcing were sustained. The rate of mean reversion defines the rate at which the transient temperature approaches the equilibrium. In FUND 3.5, the rate of temperature response is defined as a decreasing linear function of equilibrium climate sensitivity to capture the fact that the progressive heat uptake of the deep ocean causes the rate to slow at higher values of the equilibrium climate sensitivity. In FUND 3.8, the rate of temperature response has been updated to a quadratic function of the equilibrium climate sensitivity. This change reduces the sensitivity of the rate of temperature response to the level of the equilibrium climate sensitivity. Therefore in FUND 3.8, the temperature response will typically be faster than in the previous version. The overall effect of this change is likely to increase estimates of the SCC as higher temperatures are reached during the timeframe analyzed and as the same damages experienced in the previous version of the model are now experienced earlier and therefore discounted less.

14B.4.2.5 Methane

The IPCC notes a series of indirect effects of methane emissions, and has developed methods for proxying such effects when computing the global warming potential of methane (Forster et al. 2007).[8] FUND 3.8 now includes the same methods for incorporating the indirect effects of methane emissions. Specifically, the average atmospheric lifetime of methane has been set to 12 years to account for the feedback of CH4 emissions on its own lifetime. The radiative forcing associated with atmospheric methane has also been increase by 40% to account for its net impact on ozone production and increase in stratospheric water vapor. The general effect of this increased radiative forcing will be to increase the estimated SCC values, where the degree to which this occurs will be dependent upon the relative curvature of the damage functions with respect to the temperature anomaly.

14B.4.3 PAGE

PAGE09 (Hope 2012)[9] includes a number of changes from PAGE2002, the version used in the 2009 SCC interagency report. The changes that most directly affect the SCC estimates include: explicitly modeling the impacts from sea level rise, revisions to the damage function to ensure damages are constrained by GDP, a change in the regional scaling of damages, a revised treatment for the probability of a discontinuity within the damage function, and revised assumptions on adaptation. The model also includes revisions to the carbon cycle feedback and the calculation of regional temperatures. More details on PAGE2009 can be found in three working papers (Hope 2011a, 2011b, 2011c).[10, 11, 12] A description of PAGE2002 can be found in Hope (2006).[13]

14B.4.3.1 Sea Level Rise

While PAGE2002 aggregates all damages into two categories – economic and non-economic impacts - PAGE2009 adds a third explicit category: damages from sea level rise. In the previous version of the model, damages from sea level rise were subsumed by the other damage categories. PAGE09 models damages from sea level rise as increasing less than linearly with sea level based on the assumption that low-lying shoreline areas will be associated with higher damages than current inland areas. Damages from the economic and non-economic sector were adjusted to account for the introduction of this new category.

14B.4.3.2 Revised Damage Function to Account for Saturation

In PAGE09, small initial economic and non-economic benefits (negative damages) are modeled for small temperature increases, but all regions eventually experience positive economic damages from climate change, where damages are the sum of additively separable polynomial functions of temperature and sea level rise. Damages transition from this polynomial function to a logistic path once they exceed a certain proportion of remaining Gross Domestic Product (GDP) to ensure that damages do not exceed 100 percent of GDP. This differs from PAGE2002, which allowed Eastern Europe to potentially experience large benefits from temperature increases, and which also did not bound the possible damages that could be experienced.

14B.4.3.3 Regional Scaling Factors

As in the previous version of PAGE, the PAGE09 model calculates the damages for the European Union (EU) and then, assumes that damages for other regions are proportional based on a given scaling factor. The scaling factor in PAGE09 is based on the length of a region's coastline relative to the EU (Hope 2011b).[11] Because of the long coastline in the EU, other regions are, on average, less vulnerable than the EU for the same sea level and temperature increase, but all regions have a positive scaling factor. PAGE2002 based its scaling factors on four studies reported in the IPCC's third assessment report, and allowed for benefits from temperature increase in Eastern Europe, smaller impacts in developing countries, and higher damages in developing countries.

14B.4.3.4 Probability of a Discontinuity

In PAGE2002, the damages associated with a "discontinuity" were modeled as an expected value. That is, additional damages from an extreme event, such as extreme melting of the Greenland ice sheet, were multiplied by the probability of the event occurring and added to the damage estimate. In PAGE09, the probability of "discontinuity" is treated as a discrete event for each year in the model. The damages for each model run are estimated with or without a discontinuity occurring, rather than as an expected value. A large-scale discontinuity becomes possible when the temperature rises beyond some threshold value between 2 and 4°C. The probability that a discontinuity will occur beyond this threshold then increases by between 10 and 30 percent for every 1°C rise in temperature beyond the threshold. If a discontinuity occurs, the EU loses an additional 5 to 25 percent of its GDP (drawn from a triangular distribution with a mean of 15 percent) in addition to other damages, and other regions lose an amount determined by the regional scaling factor. The threshold value for a possible discontinuity is lower than in PAGE2002, while the rate at which the probability of a discontinuity increases with the temperature anomaly and the damages that result from a discontinuity are both higher than in PAGE2002. The model assumes that only one discontinuity can occur and that the impact is phased in over a period of time, but once it occurs, its effect is permanent.

14B.4.3.5 Adaptation

As in PAGE2002, adaptation is available to increase the tolerable level of temperature change and can help mitigate any climate change impacts that still occur. In PAGE this adaptation is the same regardless of the temperature change or sea level rise and is therefore akin to what is more commonly considered a reduction in vulnerability. It is modeled by modifying the temperature change and sea level rise used in the damage function or by reducing the damages by some percentage. PAGE09 assumes a smaller decrease in vulnerability than the previous version of the model and assumes that it will take longer for this change in vulnerability to be realized. In the aggregated economic sector, at the time of full implementation, this adaptation will mitigate all damages up to a temperature increase of 1°C, and for temperature anomalies between 1°C and 3°C, it will reduce damages by 15-30 percent (depending on the region). However, it takes 20 years to fully implement this adaptation. In PAGE2002, adaptation was assumed to reduce economic sector damages up to 3°C by 50-90 percent after 20 years. Beyond 3°C, no adaptation is assumed to be available to mitigate the impacts of climate change. For the non-economic sector, in PAGE09 adaptation is available to reduce 15 percent of the damages due to a temperature increase between 0°C and 2°C and is assumed to take 40 years to

fully implement, instead of 25 percent of the damages over 20 years assumed in PAGE2002. Similarly, adaptation is assumed to alleviate 25-50 percent of the damages from the first 0.20 to 0.25 meters of sea level rise but is assumed to be ineffective thereafter. Hope (2011c)[12] estimates that the less optimistic assumptions regarding the ability to offset impacts of temperature and sea level rise via adaptation increase the SCC by approximately 30 percent.

14B.4.3.6 Other Noteworthy Changes

Two other changes in the model are worth noting. A revised carbon cycle feedback is introduced to simulate decreased CO_2 absorption by the terrestrial biosphere and ocean as the temperature rises. This feedback is linear in the average global and annual temperature anomaly but is capped at a maximum value. In the previous version of PAGE, an additional amount was added to the CO_2 emissions each period to account for a decrease in ocean absorption and a loss of soil carbon. Also updated is the method by which the average global and annual temperature anomaly is downscaled to determine annual average regional temperature anomalies to be used in the regional damage functions. In the previous version of PAGE, the scaling was determined solely based on regional difference in emissions of sulfate aerosols. In PAGE09, this regional temperature anomaly is further adjusted using an additive factor that is based on the average absolute latitude of a region relative to the area weighted average absolute latitude of the Earth's landmass.

14B.5 REVISED SCC ESTIMATES

The updated versions of the three integrated assessment models were run using the same methodology detailed in the 2010 TSD.[1] The approach along with the inputs for the socioeconomic emissions scenarios, equilibrium climate sensitivity distribution, and discount rate remains the same. This includes the five reference scenarios based on the EMF-22 modeling exercise, the Roe and Baker equilibrium climate sensitivity distribution calibrated to the Fourth Assessment Report of the IPCC, and three constant discount rates of 2.5, 3, and 5 percent.

As was previously the case, the use of three models, three discount rates, and five scenarios produces 45 separate distributions for the SCC. The approach laid out in the TSD applied equal weight to each model and socioeconomic scenario in order to reduce the dimensionality down to three separate distributions representative of the three discount rates. The interagency group selected four values from these distributions for use in regulatory analysis. Three values are based on the average SCC across models and socio-economic-emissions scenarios at the 2.5, 3, and 5 percent discount rates, respectively. The fourth value was chosen to represent the higher-than-expected economic impacts from climate change further out in the tails of the SCC distribution. For this purpose, the 95th percentile of the SCC estimates at a 3 percent discount rate was chosen. (A detailed set of percentiles by model and scenario combination is available in Annex A.) As noted in the original TSD, "the 3 percent discount rate is the central value, and so the central value that emerges is the average SCC across models at the 3 percent discount rate" (TSD, p. 25). However, for purposes of capturing the uncertainties involved in regulatory impact analysis, the interagency group emphasizes the importance and value of including all four SCC values.

Table 14B.5.1 shows the four selected SCC estimates in five year increments from 2010 to 2050. Values for 2010, 2020, 2030, 2040, and 2050 are calculated by first combining all outputs (10,000 estimates per model run) from all scenarios and models for a given discount rate. Values for the years in between are calculated using basic linear interpolation. The full set of annual SCC estimates between 2010 and 2050 is reported in Annex A.

Table 14B.5.1 Revised Social Cost of CO_2, 2010 – 2050 (in 2007 dollars per ton of CO_2)

Discount Rate Year	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010	10	31	50	86
2015	11	36	56	105
2020	12	42	62	123
2025	14	46	68	138
2030	16	50	73	152
2035	18	55	78	168
2040	21	60	84	183
2045	23	64	89	197
2050	26	69	95	212

The SCC estimates using the updated versions of the models are higher than those reported in the TSD due to the changes to the models outlined in section 14B.4. Figure 14B.5.1 illustrates where the four SCC values for 2020 fall within the full distribution for each discount rate based on the combined set of runs for each model and scenario (150,000 estimates in total for each discount rate). In general, the distributions are skewed to the right and have long tails. The Figure also shows that the lower the discount rate, the longer the right tail of the distribution.

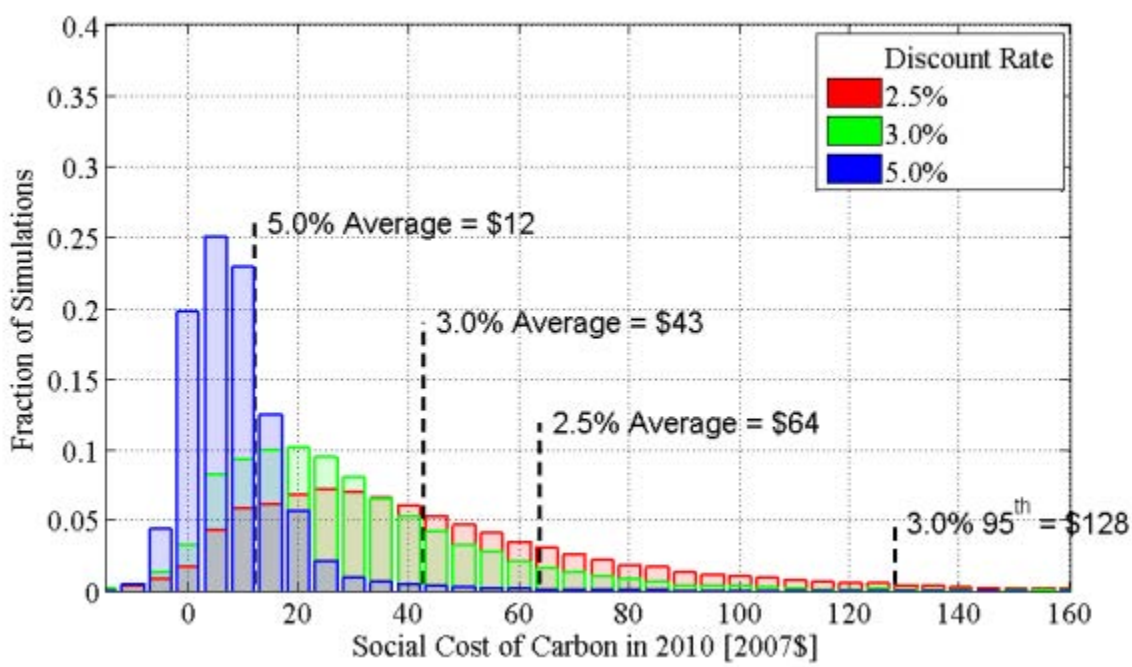

Figure 14B.5.1 Distribution of SCC Estimates for 2010 (in 2007$ per ton CO_2)

As was the case in the original TSD, the SCC increases over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change. The approach taken by the interagency group is to allow the growth rate to be determined endogenously by the models through running them for a set of perturbation years out to 2050. Table 14B.5.2 illustrates how the growth rate for these four SCC estimates varies over time.

Table 14B.5.2 Average Annual Growth Rates of SCC Estimates between 2010 and 2050

Average Annual Rate (%)	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010-2020	1.2%	3.2%	2.4%	4.4%
2020-2030	3.4%	2.1%	1.7%	2.3%
2030-2040	3.0%	1.9%	1.5%	2.0%
2040-2050	2.6%	1.6%	1.3%	1.6%

The future monetized value of emission reductions in each year (the SCC in year *t* multiplied by the change in emissions in year *t*) must be discounted to the present to determine its total net present value for use in regulatory analysis. As previously discussed in the original TSD, damages from future emissions should be discounted at the same rate as that used to calculate the SCC estimates themselves to ensure internal consistency – *i.e.*, future damages from climate change, whether they result from emissions today or emissions in a later year, should be discounted using the same rate.

14B.6 OTHER MODEL LIMITATIONS OR RESEARCH GAPS

The 2010 interagency SCC technical support report discusses a number of important limitations for which additional research is needed. In particular, the document highlights the need to improve the quantification of both non-catastrophic and catastrophic damages, the treatment of adaptation and technological change, and the way in which inter-regional and inter-sectoral linkages are modeled. It also discusses the need to more carefully assess the implications of risk aversion for SCC estimation as well as the inability to perfectly substitute between climate and non-climate goods at higher temperature increases, both of which have implications for the discount rate used. EPA, DOE, and other agencies continue to engage in long-term research work on modeling and valuation of climate impacts that we expect will inform improvements in SCC estimation in the future.

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14B.7 ANNEX A

Table 14B.7.1 Annual SCC Values: 2010-2050 (2007$/ton CO_2)

Discount Rate Year	5.0% Avg	3.0% Avg	2.5% Avg	3.0% 95th
2010	10	31	50	86
2011	11	32	51	90
2012	11	33	53	93
2013	11	34	54	97
2014	11	35	55	101
2015	11	36	56	105
2016	11	38	57	108
2017	11	39	59	112
2018	12	40	60	116
2019	12	41	61	120
2020	12	42	62	123
2021	12	42	63	126
2022	13	43	64	129
2023	13	44	65	132
2024	13	45	66	135
2025	14	46	68	138
2026	14	47	69	141
2027	15	48	70	149
2028	15	49	71	146
2029	15	49	72	149
2030	16	50	73	152
2031	16	51	74	155
2032	17	52	75	158
2033	17	53	76	161
2034	18	54	77	164
2035	18	55	78	168
2036	19	56	79	171
2037	19	57	81	174
2038	20	58	82	177
2039	20	59	83	180
2040	21	60	84	183
2041	21	61	85	186
2042	22	61	86	189
2043	22	62	87	192
2044	23	63	88	194
2045	23	64	89	197
2046	24	65	90	200
2047	24	66	92	203
2048	25	67	93	206
2049	25	68	94	209
2050	26	69	95	212

Table 14B.7.2 202 Global SCC Estimates at 2.5 Percent Discount Rate (2007$/ton CO_2)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95th	99th
Scenario	PAGE									
IMAGE	6	10	15	26	55	123	133	313	493	949
MERGE Optimistic	4	6	8	15	32	75	79	188	304	621
MESSAGE	4	7	10	19	41	104	103	266	463	879
MiniCAM Base	5	8	12	21	45	102	108	255	412	835
5th Scenario	2	4	6	11	24	81	66	192	371	915
Scenario	DICE									
IMAGE	25	31	37	47	64	72	92	123	139	161
MERGE Optimistic	14	18	20	26	36	40	50	65	74	85
MESSAGE	20	24	28	37	51	58	71	95	109	221
MiniCAM Base	20	25	29	38	53	61	76	102	117	135
5th Scenario	17	22	25	33	45	52	65	91	106	126
Scenario	FUND									
IMAGE	-14	-2	4	15	31	39	55	86	107	157
MERGE Optimistic	-6	1	6	14	27	35	46	70	87	141
MESSAGE	-16	-5	1	11	24	31	43	67	83	126
MiniCAM Base	-7	2	7	16	32	39	55	83	103	158
5th Scenario	-29	-13	-6	4	16	21	32	53	69	103

Table 14B.7.3 SCC Estimates at 3 Percent Discount Rate (2007$/ton CO2)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95th	99th
Scenario	PAGE									
IMAGE	4	7	9	17	36	87	91	228	369	696
MERGE Optimistic	2	4	6	10	22	54	55	136	222	461
MESSAGE	3	5	7	13	28	72	71	188	316	614
MiniCAM Base	3	5	7	13	29	70	72	177	288	597
5th Scenario	1	3	4	7	16	55	46	130	252	632
Scenario	DICE									
IMAGE	16	21	24	32	43	48	60	79	90	102
MERGE Optimistic	10	13	15	19	25	28	35	44	50	58
MESSAGE	14	18	20	26	35	40	49	64	73	83
MiniCAM Base	13	17	20	26	35	39	49	65	73	85
5th Scenario	12	15	17	22	30	34	43	58	67	79
Scenario	FUND									
IMAGE	-13	-4	0	8	18	23	33	51	65	99
MERGE Optimistic	-7	-1	2	8	17	21	29	45	57	95
MESSAGE	-14	-6	-2	5	14	18	26	41	52	82
MiniCAM Base	-7	-1	3	9	19	23	33	50	63	101
5th Scenario	-22	-11	-6	1	8	11	18	31	40	62

Table 14B.7.4 2020 Global SCC Estimates at 5 Percent Discount Rate (2007$/ton CO_2)

Percentile	1st	5th	10th	25th	50th	Avg	75th	90th	95th	99th
Scenario	PAGE									
IMAGE	1	2	2	4	10	27	26	68	118	234
MERGE Optimistic	1	1	2	3	6	17	17	43	72	149
MESSAGE	1	1	2	4	8	23	22	58	102	207
MiniCAM Base	1	1	2	3	8	20	20	52	90	182
5th Scenario	0	1	1	2	5	17	14	39	75	199
Scenario	DICE									
IMAGE	6	8	9	11	14	15	18	22	25	27
MERGE Optimistic	4	5	6	7	9	10	12	15	16	18
MESSAGE	6	7	8	10	12	13	16	20	22	25
MiniCAM Base	5	6	7	8	11	12	14	18	20	22
5th Scenario	5	6	6	8	10	11	14	17	19	21
Scenario	FUND									
IMAGE	-9	-5	-4	-1	2	3	6	10	14	24
MERGE Optimistic	-6	-4	-2	0	3	4	6	11	15	26
MESSAGE	-10	-6	-4	-1	1	2	5	9	12	21
MiniCAM Base	-7	-4	-2	0	3	4	6	11	14	25
5th Scenario	-11	-7	-5	-3	0	0	3	5	7	13

Table 14B.7.5 Additional Summary Statistics of 2020 Global SCC Estimates

Discount Rate Statistic:	5.0%				3.0%				2.5%			
	Mean	Variance	Skewness	Kurtosis	Mean	Variance	Skewness	Kurtosis	Mean	Variance	Skewness	Kurtosis
DICE	12	26	2	15	38	409	3	24	57	1097	3	30
PAGE	21	1481	5	32	68	13712	4	22	97	26878	4	23
FUND	3	41	5	179	19	1452	-42	8727	33	6154	-73	14931

14B.8 ANNEX B

The November 2013 revision of this technical support document is based on two corrections to the runs based on the FUND model. First, the potential dry land loss in the algorithm that estimates regional coastal protections was mispecified in the model's computer code. This correction is covered in an erratum to Anthoff and Tol (2013) published in the same journal (Climatic Change) in October 2013 (Anthoff and Tol (2013b)). Second, the equilibrium climate sensitivity distribution was inadvertently specified as a truncated Gamma distribution (the default in FUND) as opposed to the truncated Roe and Baker distribution as was intended. The truncated Gamma distribution used in the FUND runs had approximately the same mean and upper truncation point, but lower variance and faster decay of the upper tail, as compared to the intended specification based on the Roe and Baker distribution. The difference between the original estimates reported in the May 2013 version of this technical support document and this revision are generally one dollar or less.

The July 2015 revision of this technical support document is based on two corrections. First, the DICE model had been run up to 2300 rather than through 2300, as was intended, thereby leaving out the marginal damages in the last year of the time horizon. Second, due to an indexing error, the results from the PAGE model were in 2008 U.S. dollars rather than 2007 U.S. dollars, as was intended. In the current revision, all models have been run through 2300, and all estimates are in 2007 U.S. dollars. On average the revised SCC estimates are one dollar less than the mean SCC estimates reported in the November 2013 version of this technical support document. The difference between the 95th percentile estimates with a 3-percent discount rate is slightly larger, as those estimates are heavily influenced by results from the PAGE model.

CHAPTER 15. UTILITY IMPACT ANALYSIS

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CHAPTER 15. UTILITY IMPACT ANALYSIS

15.1 INTRODUCTION

In the utility impact analysis, the U.S. Department of Energy (DOE) analyzes the changes in electric installed capacity and power generation that result for each trial standard level (TSL).

The utility impact analysis is based on output of the DOE/Energy Information Administration (EIA)'s National Energy Modeling System (NEMS).[a] NEMS is a public domain, multi-sectored, partial equilibrium model of the U.S. energy sector. Each year, DOE/EIA uses NEMS to produce an energy forecast for the United States, the Annual Energy Outlook (AEO). The EIA publishes a Reference case, which incorporates all existing energy-related policies at the time of publication, and a variety of side cases which analyze the impact of different policies, energy price and market trends. As of 2014, DOE is using a new methodology based on results published for the *Annual Energy Outlook 2015(AEO 2015)* Reference case and a set of the side cases that implement a variety of efficiency-related policies.[2]

The new approach retains key aspects of DOE's previous methodology, and provides some improvements:

- The assumptions used in the AEO reference case and side cases are fully documented and receive detailed public scrutiny.
- NEMS is updated each year, with each edition of the AEO, to reflect changes in energy prices, supply trends, regulations, *etc.*
- The comprehensiveness of NEMS permits the modeling of interactions among the various energy supply and demand sectors.
- Using EIA published side cases to estimate the utility impacts enhances the transparency of DOE's analysis.
- The variability in impacts estimates from one edition of AEO to the next will be reduced under the new approach.

The methodology is presented in appendix 15A. The methodology is described in more detail in K. Coughlin, "Utility Sector Impacts of Reduced Electricity Demand."[3]

This chapter presents the results for residential boilers.

15.2 METHODOLOGY

DOE estimates the marginal impacts of reduction in energy demand on the energy supply sector. In principle, marginal values should provide a better estimate of the actual impact of

[a] For more information on NEMS, refer to the U.S. Department of Energy, Energy Information Administration documentation. A useful summary is *National Energy Modeling System: An Overview*.[1]

energy conservation standards. DOE represents these marginal impacts using time series of *impact factors*.

The impact factors are calculated based on output from NEMS for the *AEO 2015*. NEMS uses predicted growth in demand for each end use to build up a projection of the total electric system load growth. The system load shapes are converted internally to load duration curves, which are then used to estimate the most cost-effective additions to capacity. When electricity demand deviates from the AEO reference case, in general there are three inter-related effects: the annual generation (TWh) from the stock of electric generating capacity changes, the total generation capacity itself (GW) may change, and the mix of capacity types and technologies may change. Technology changes lead to a change in the proportion of fuel consumption to electricity generated (referred to as the heat rate). Each of these effects can vary for different types of end use. The change in total generating capacity is sensitive to the degree to which the end-use is peak coincident, while the capacity mix is sensitive to the hourly load shape associated with the end use. Changes in generation by fuel type lead in turn to changes in total power sector emissions of SO_2, NO_x, Hg and CO_2.

DOE defined impact factors describing the change in emissions, installed capacity, and fuel consumption per unit reduction of site electricity demand. The impact factors vary by sector and end-use, as well as by year. DOE multiplied the impact factors by the stream of site energy savings calculated in the NIA (chapter 10) to produce estimates of the utility impacts. The utility impact factors are presented in appendix 15A. For residential boilers, DOE used the impact factors for space heating in homes and commercial buildings for the annual fuel utilization efficiency (AFUE) standards, and the ones for refrigeration (base load) for the standby and off mode standards.

15.3 UTILITY IMPACT RESULTS

15.3.1 Installed Capacity

The figures in this section show the changes in U.S. electricity installed capacity that result for each TSL by major plant type for selected years. Figure 15.3.1 through Figure 15.3.6 present results for AFUE TSLs, and Figure 15.3.7 through Figure 15.3.12 present results for standby and off mode TSLs. The changes have been calculated based on the impact factors for capacity presented in appendix 15A. Units are megawatts of capacity per gigawatt-hour of site electricity use (MW/GWh).[b] Note that a negative number means an increase in capacity under a TSL.

[b] These units are identical to GW/TWh.

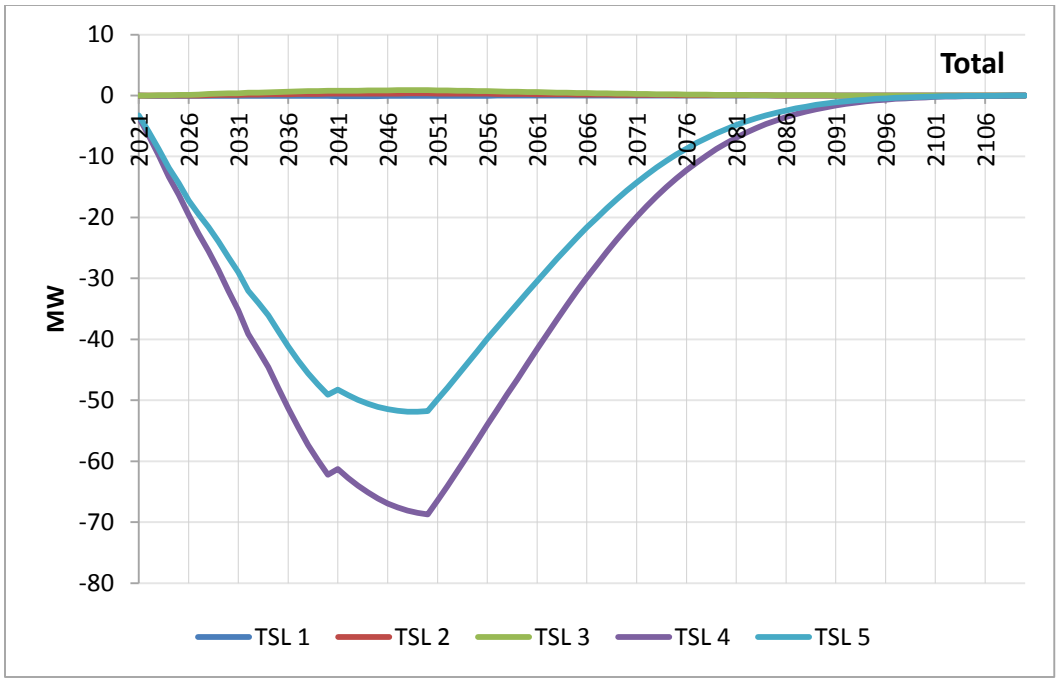

Figure 15.3.1 Total Electric Capacity Reduction for AFUE Standards

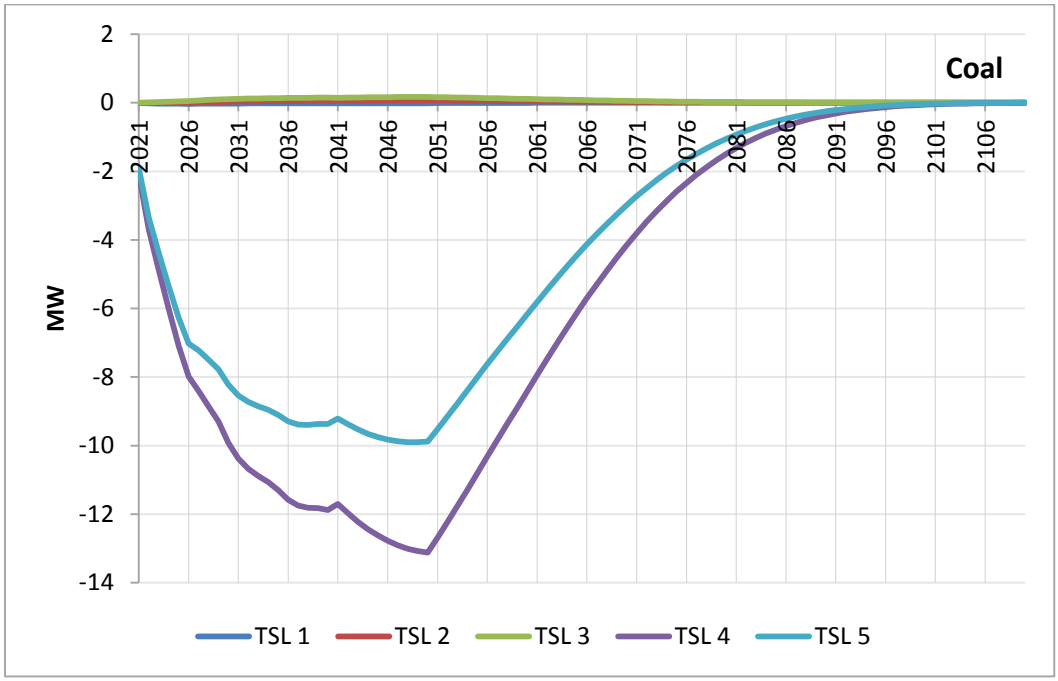

Figure 15.3.2 Coal Capacity Reduction for AFUE Standards

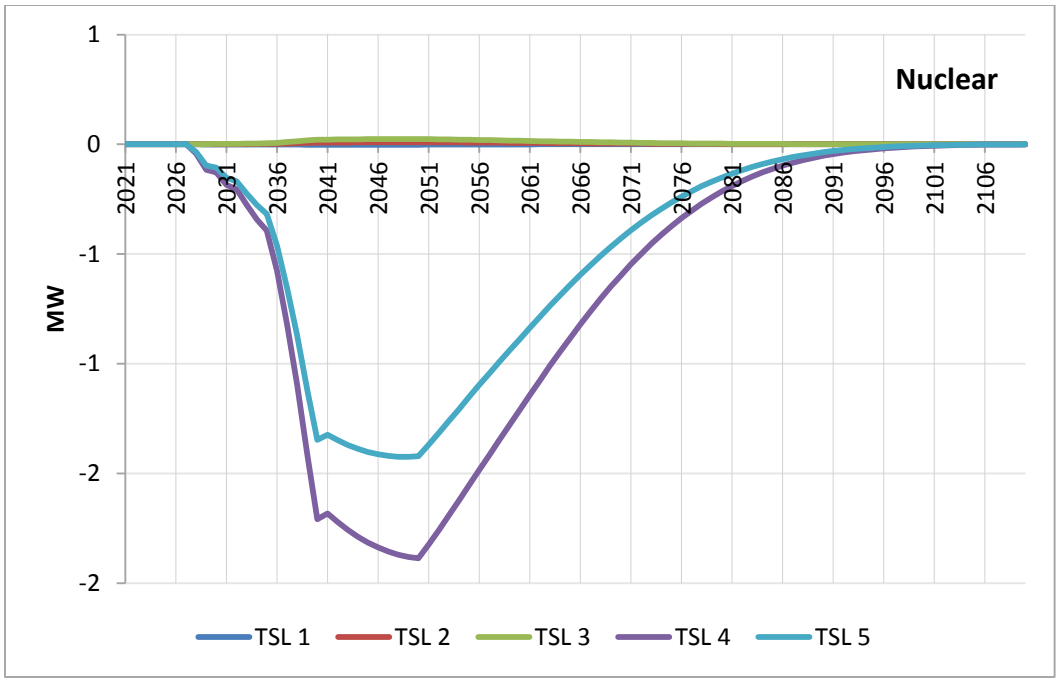

Figure 15.3.3 Nuclear Capacity Reduction for AFUE Standards

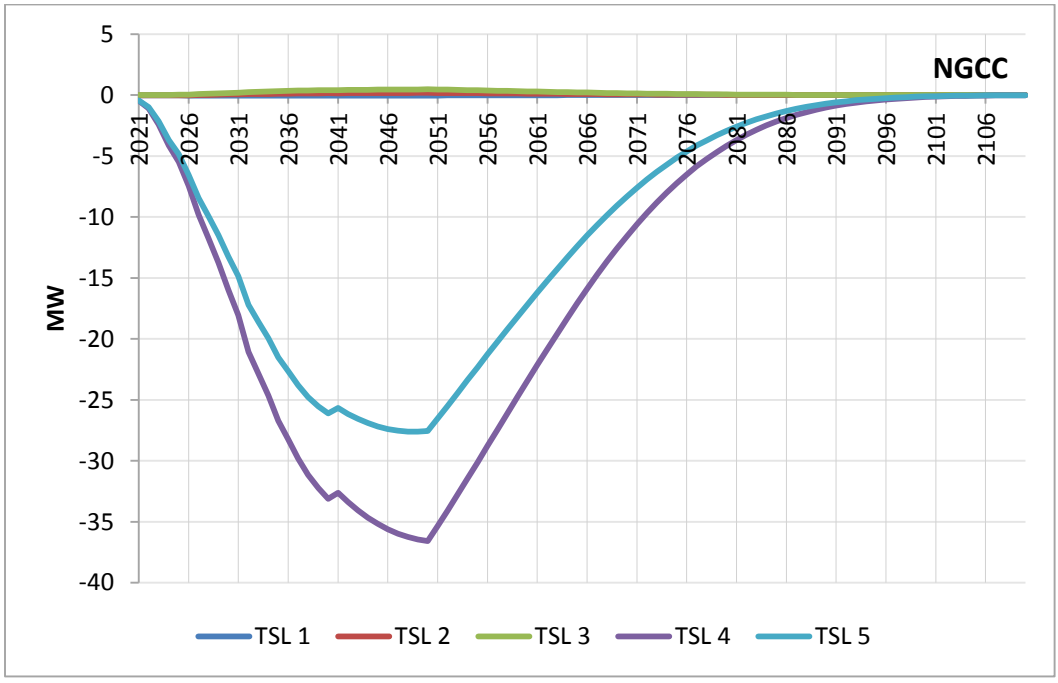

Figure 15.3.4 Gas Combined Cycle Capacity Reduction for AFUE Standards

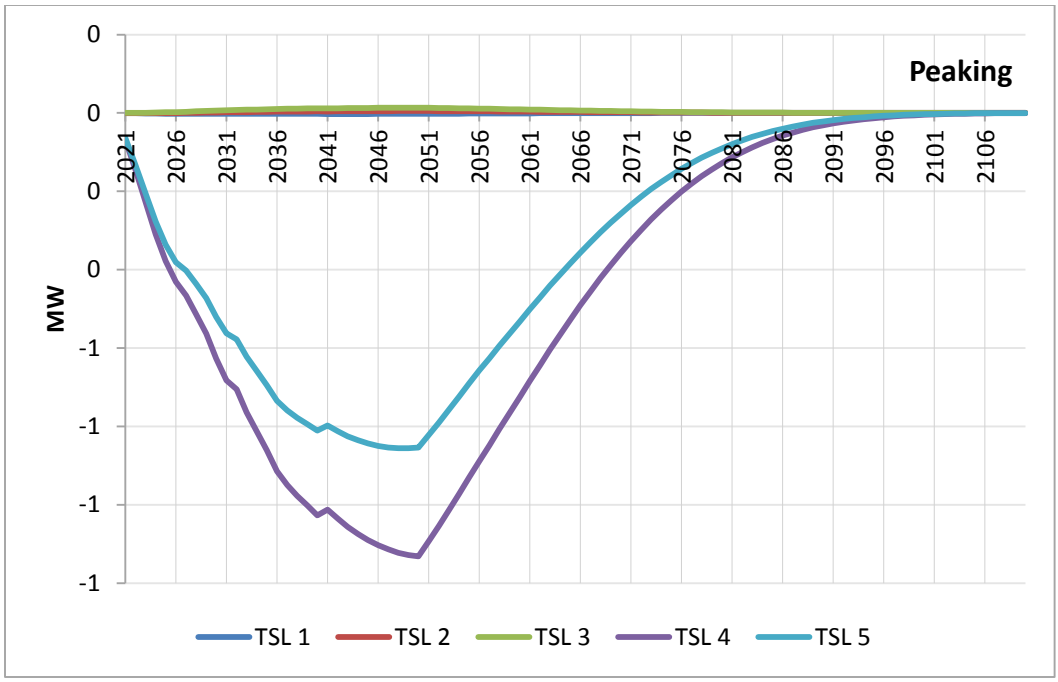

Figure 15.3.5 Peaking Capacity Reduction for AFUE Standards

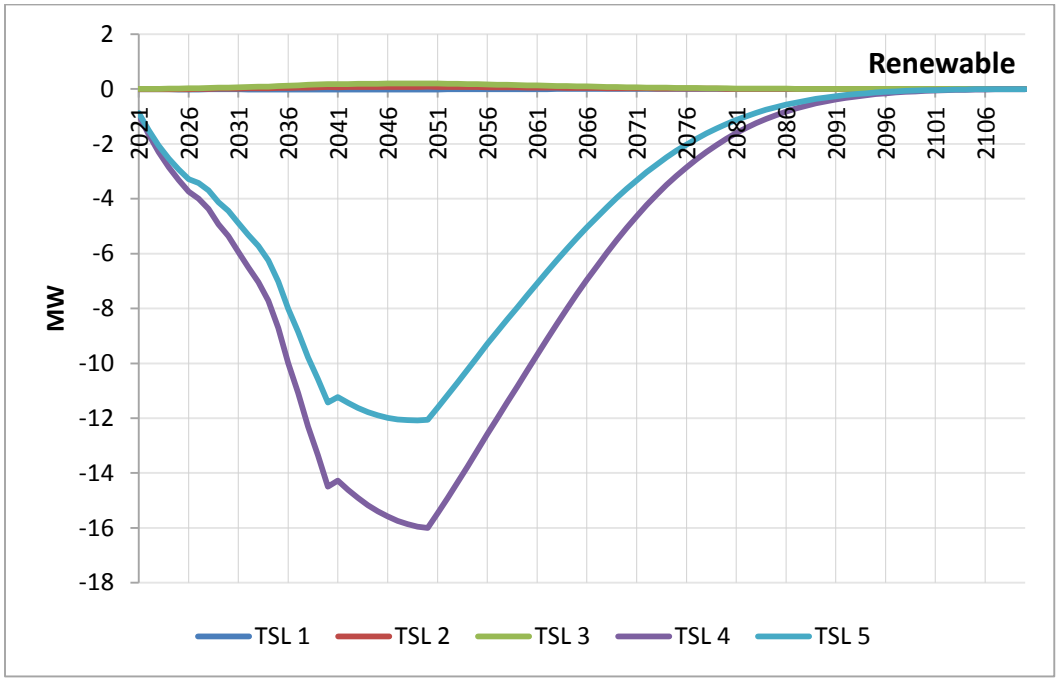

Figure 15.3.6 Renewables Capacity Reduction for AFUE Standards

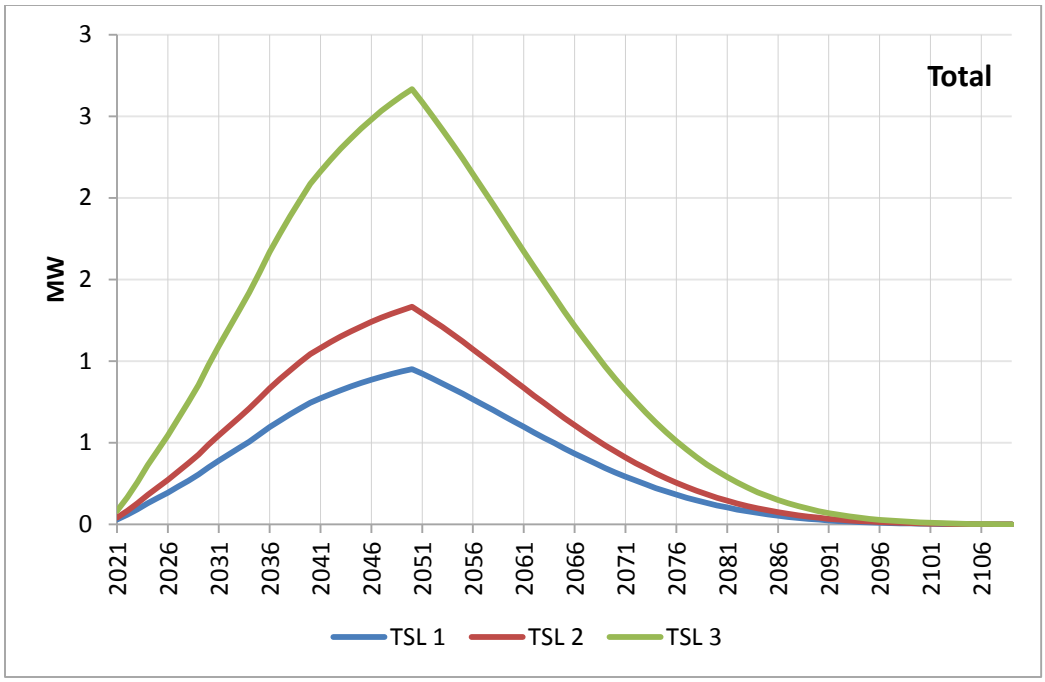

Figure 15.3.7 Total Electric Capacity Reduction for Standby and Off Mode Standards

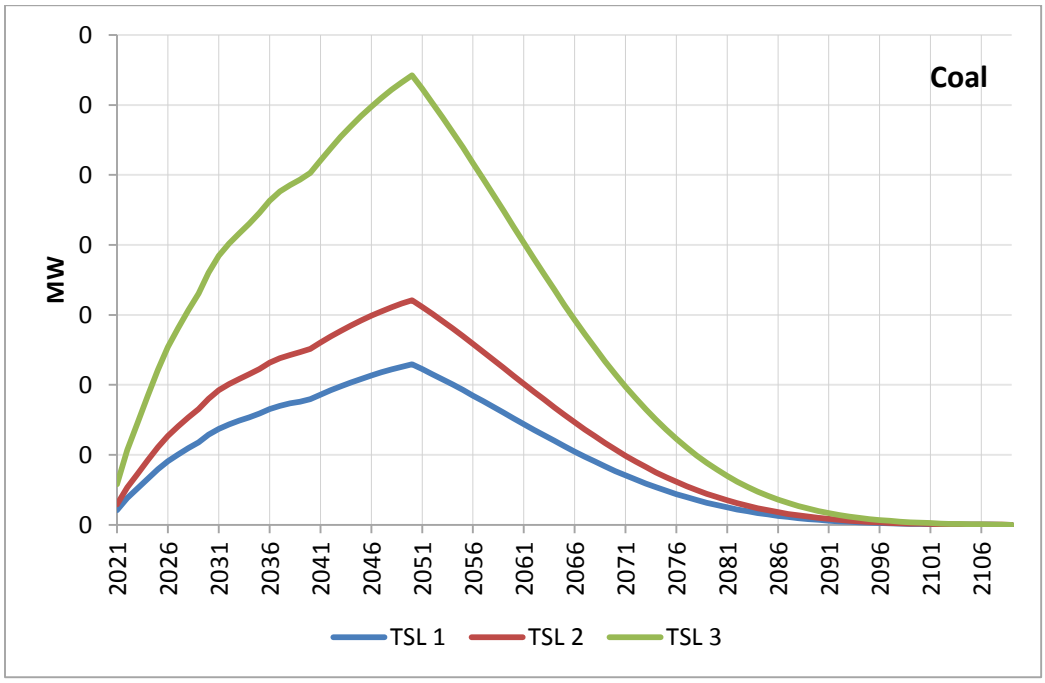

Figure 15.3.8 Coal Capacity Reduction for Standby and Off Mode Standards

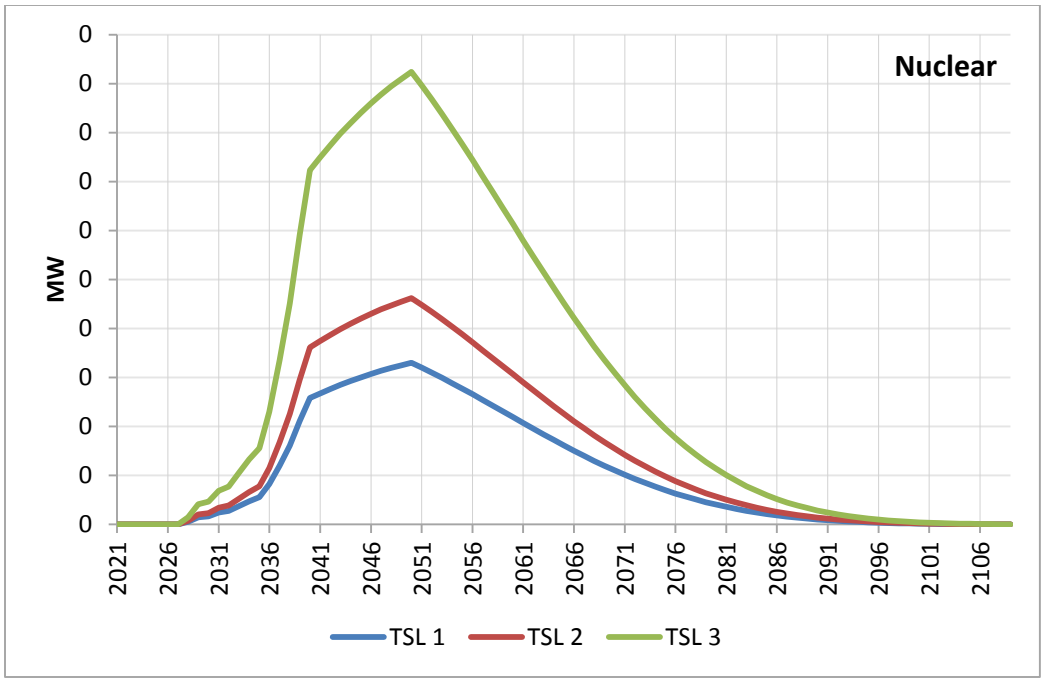

Figure 15.3.9 Nuclear Capacity Reduction for Standby and Off Mode Standards

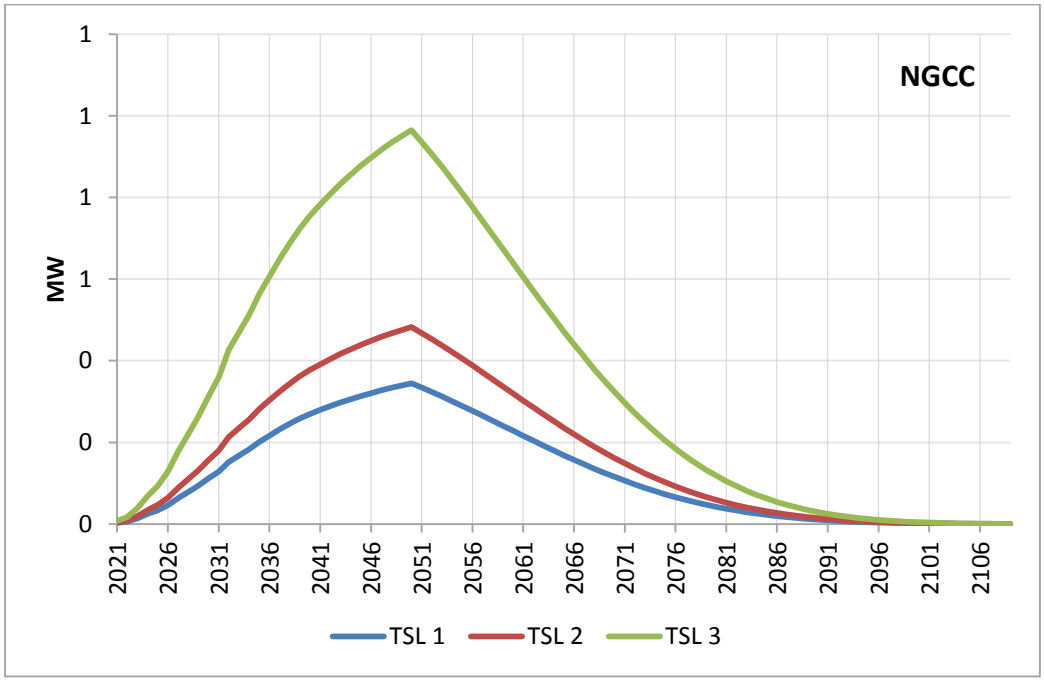

Figure 15.3.10 Gas Combined Cycle Capacity Reduction for Standby and Off Mode Standards

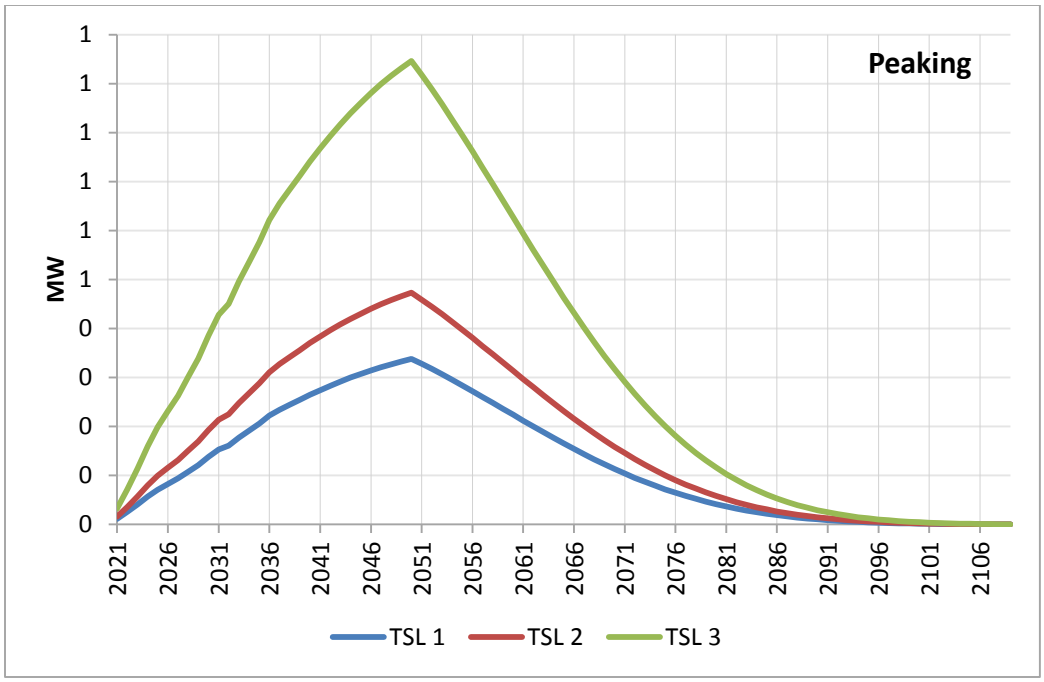

Figure 15.3.11 Peaking Capacity Reduction for Standby and Off Mode Standards

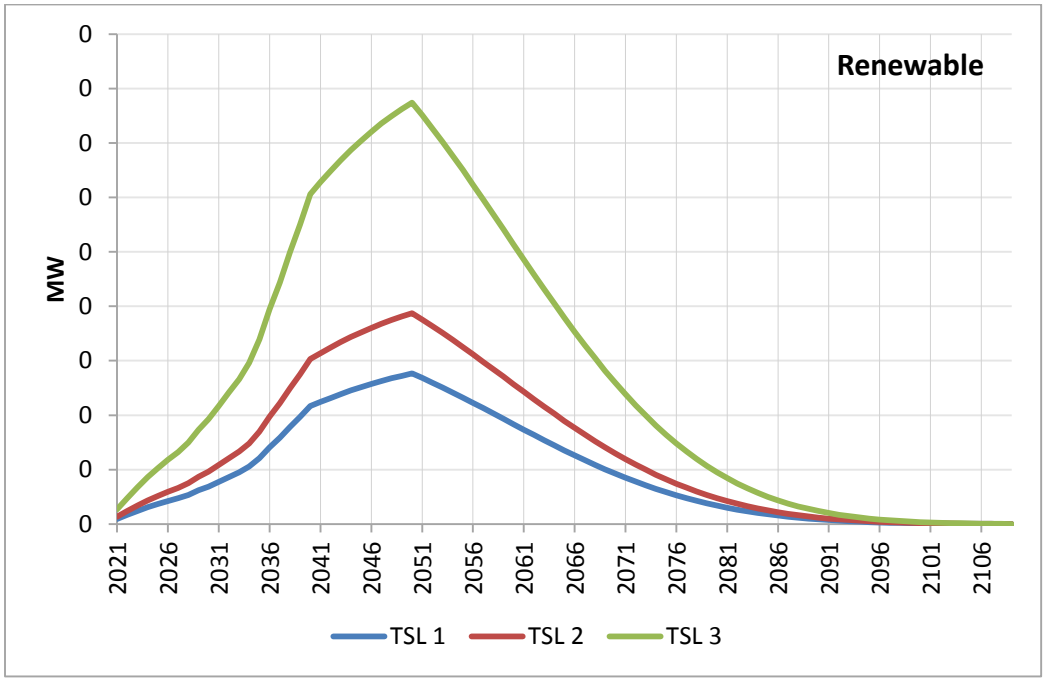

Figure 15.3.12 Renewables Capacity Reduction for Standby and Off Mode Standards

15.3.2 Electricity Generation

The figures in this section show the annual change in electricity generation that result for each TSL by plant type. Figure 15.3.13 through Figure 15.3.18 present results for AFUE TSLs, and Figure 15.3.19 through Figure 15.3.24 present results for standby and off mode TSLs. The

change by plant type has been calculated based on factors estimated as described in appendix 15A.

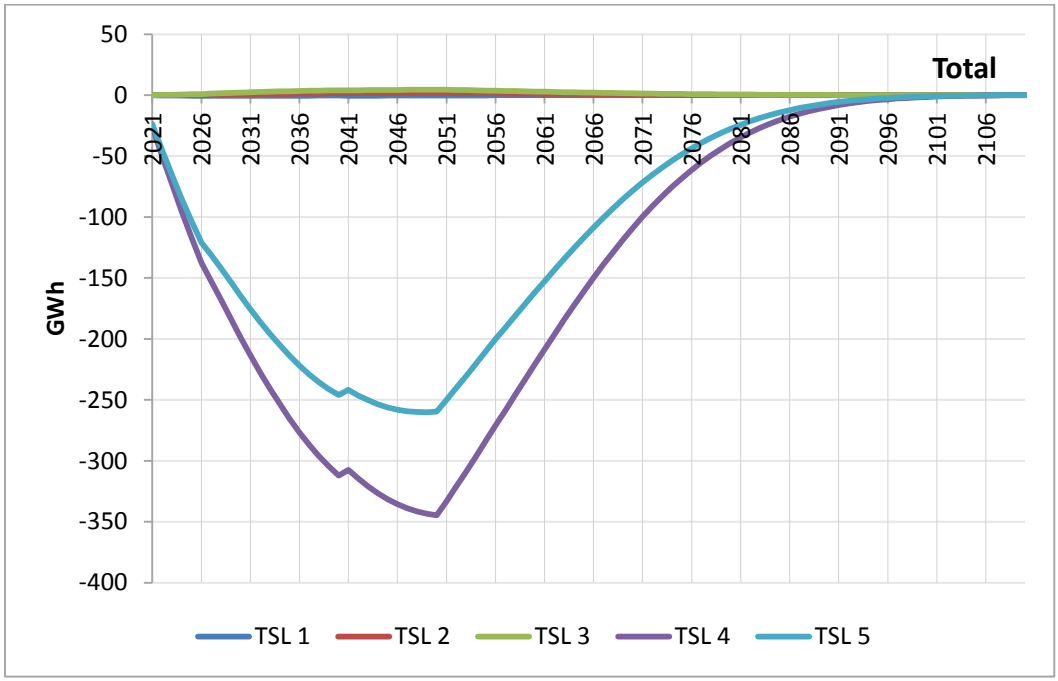

Figure 15.3.13 Total Generation Reduction for AFUE Standards

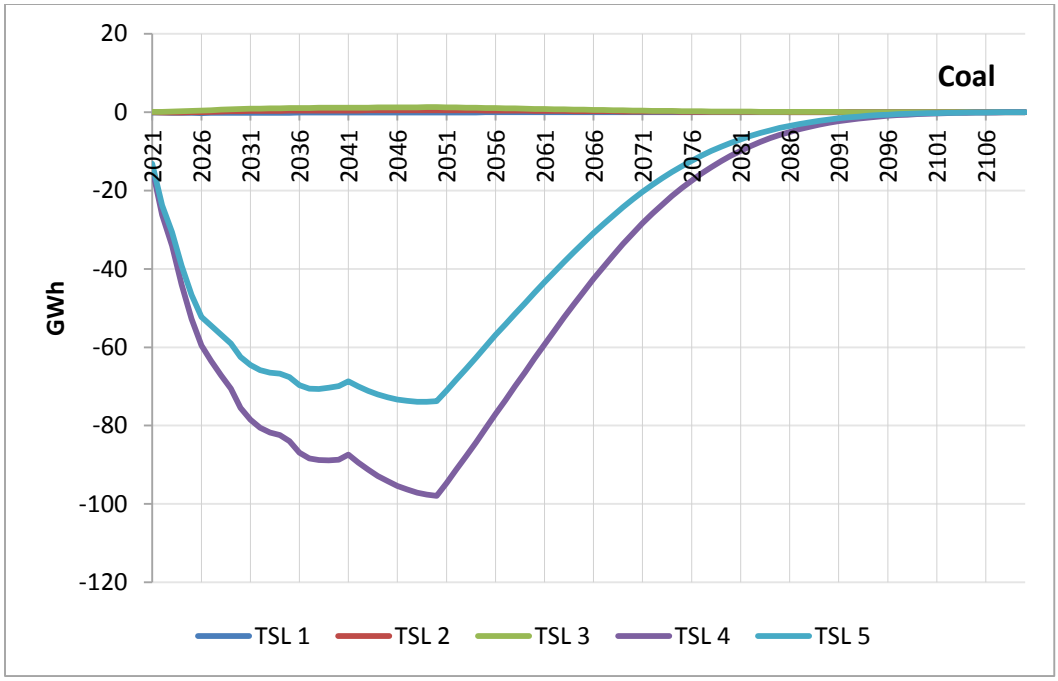

Figure 15.3.14 Coal Generation Reduction for AFUE Standards

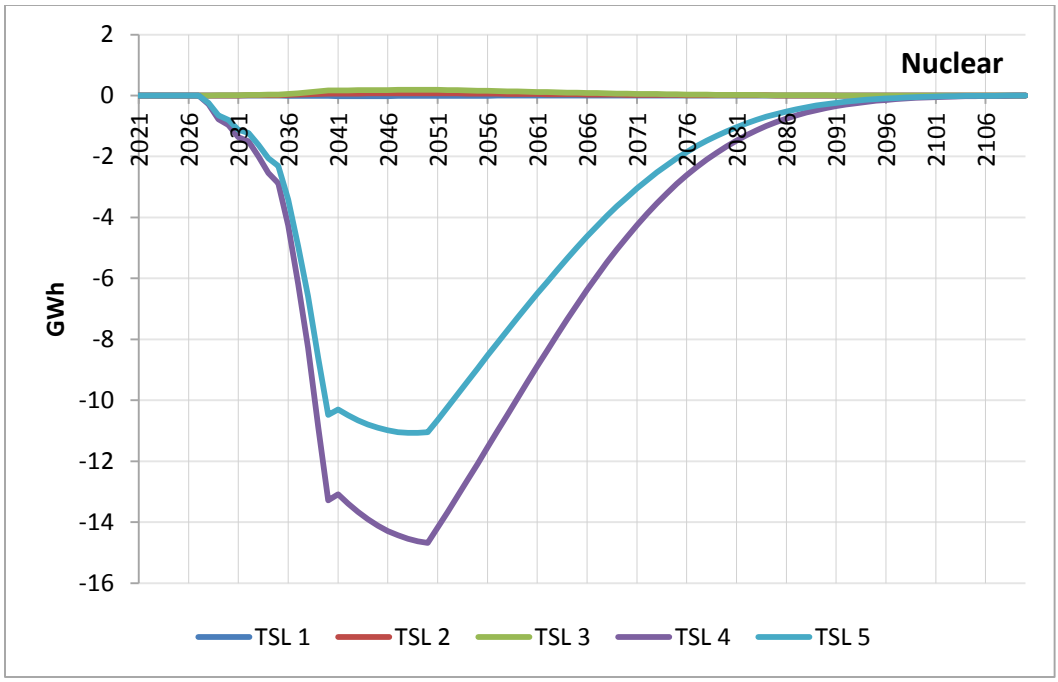

Figure 15.3.15 Nuclear Generation Reduction for AFUE Standards

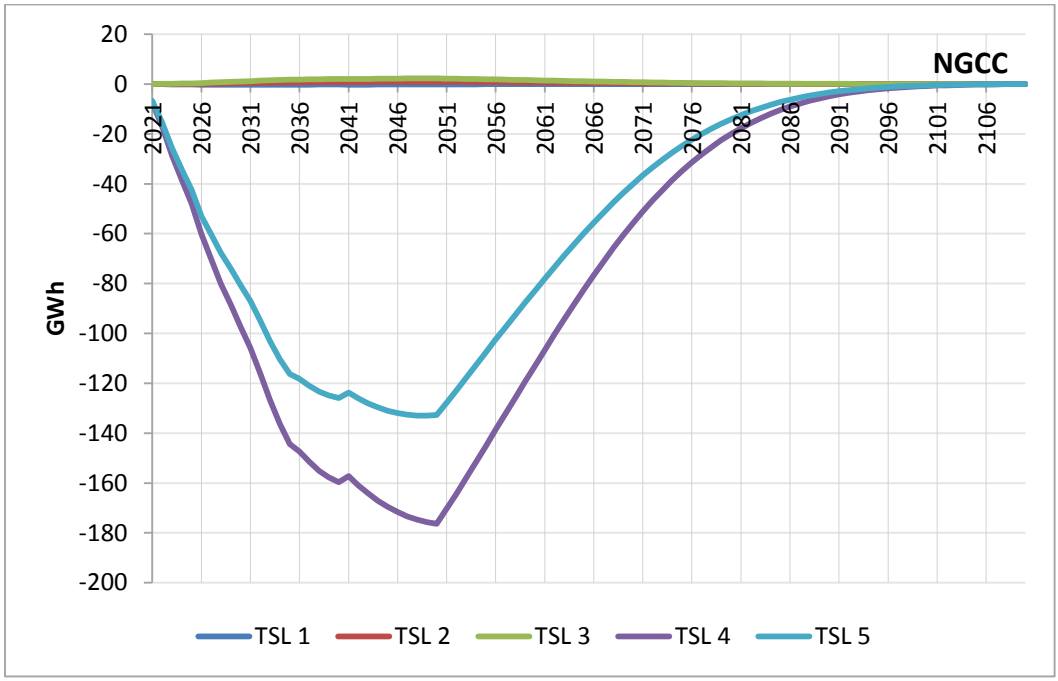

Figure 15.3.16 Gas Combined Cycle Generation Reduction for AFUE Standards

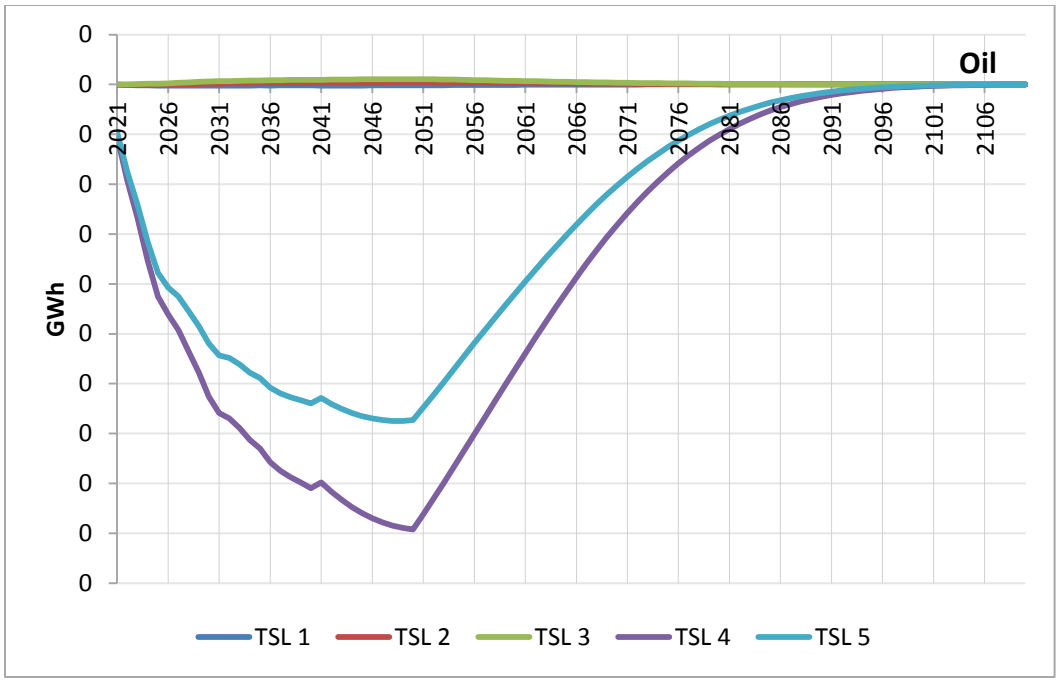

Figure 15.3.17 Oil Generation Reduction for AFUE Standards

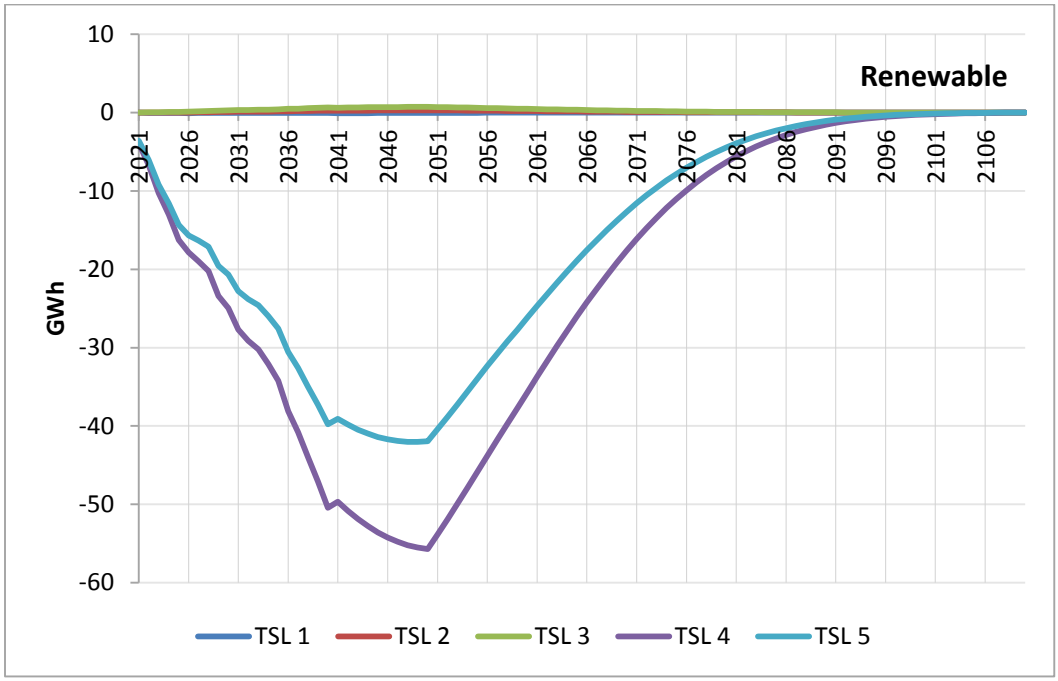

Figure 15.3.18 Renewables Generation Reduction for AFUE Standards

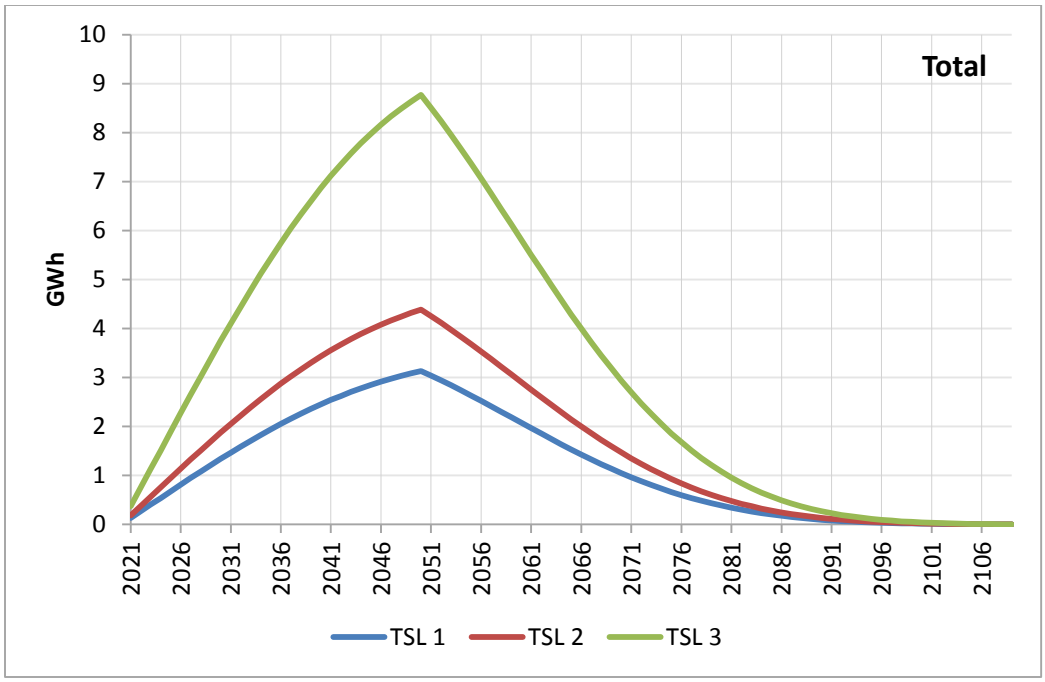

Figure 15.3.19 Total Generation Reduction for Standby and Off Mode Standards

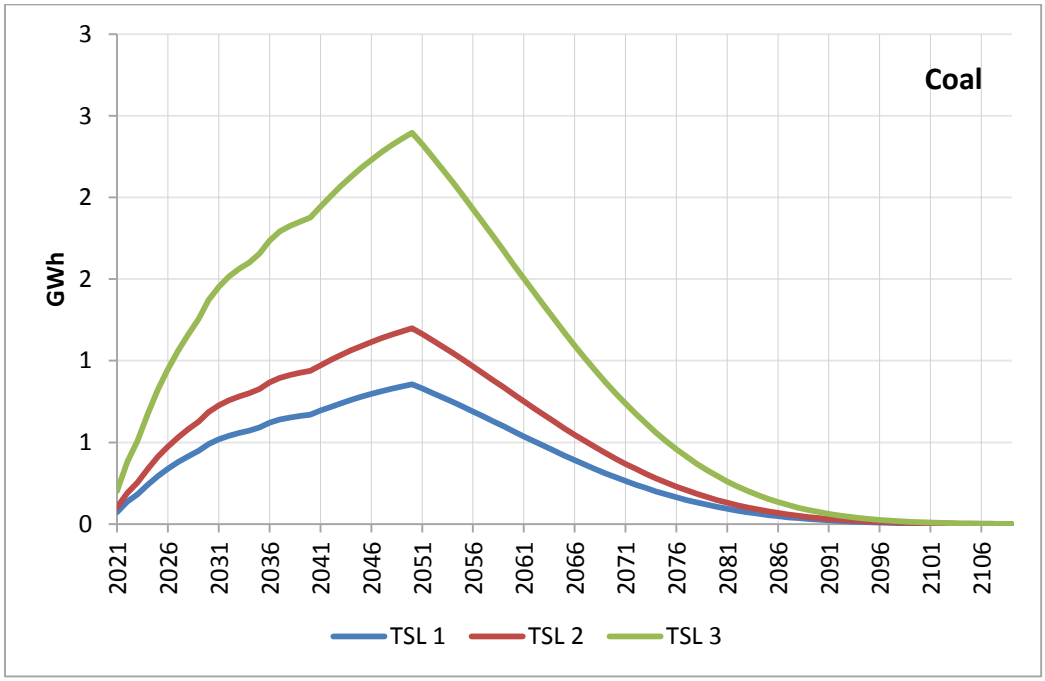

Figure 15.3.20 Coal Generation Reduction for Standby and Off Mode Standards

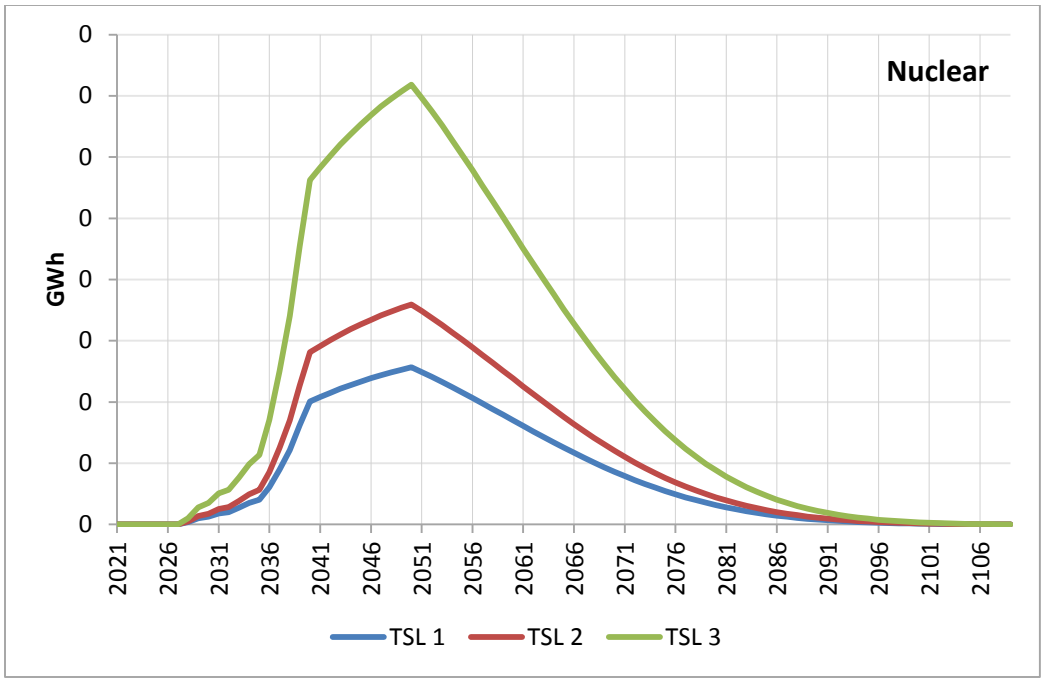

Figure 15.3.21 Nuclear Generation Reduction for Standby and Off Mode Standards

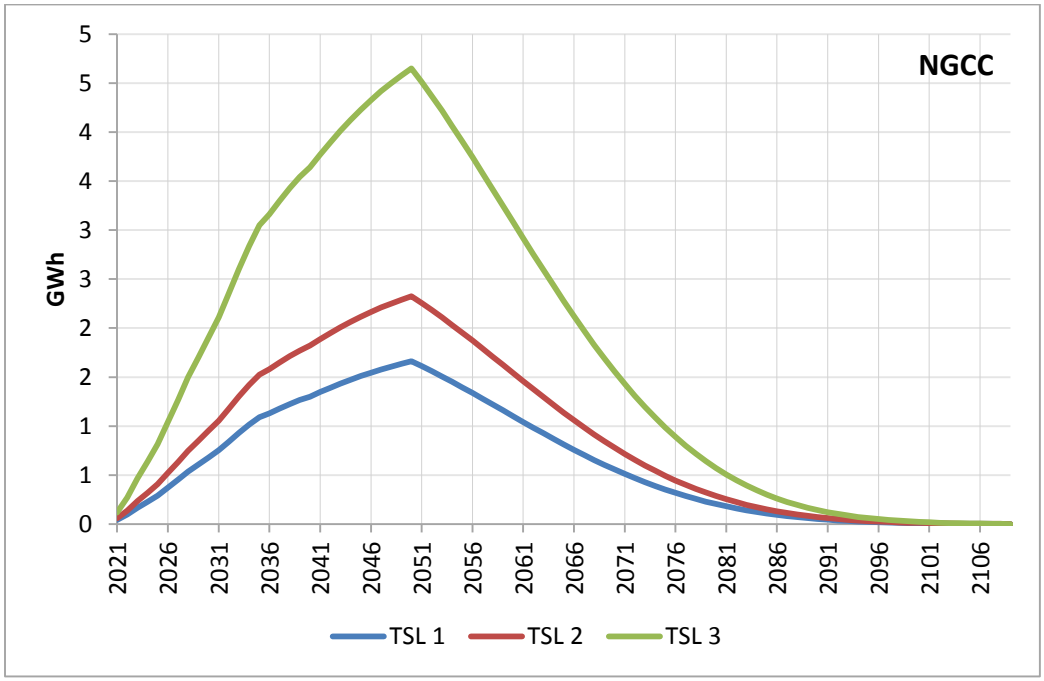

Figure 15.3.22 Gas Combined Cycle Generation Reduction for Standby and Off Mode Standards

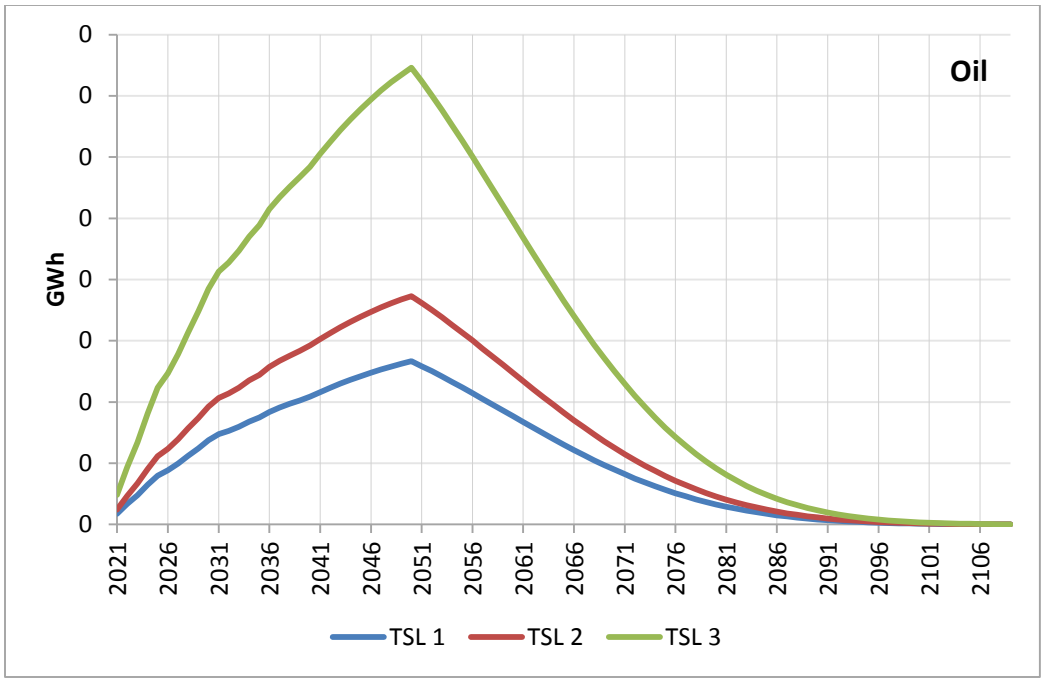

Figure 15.3.23 Oil Generation Reduction for Standby and Off Mode Standards

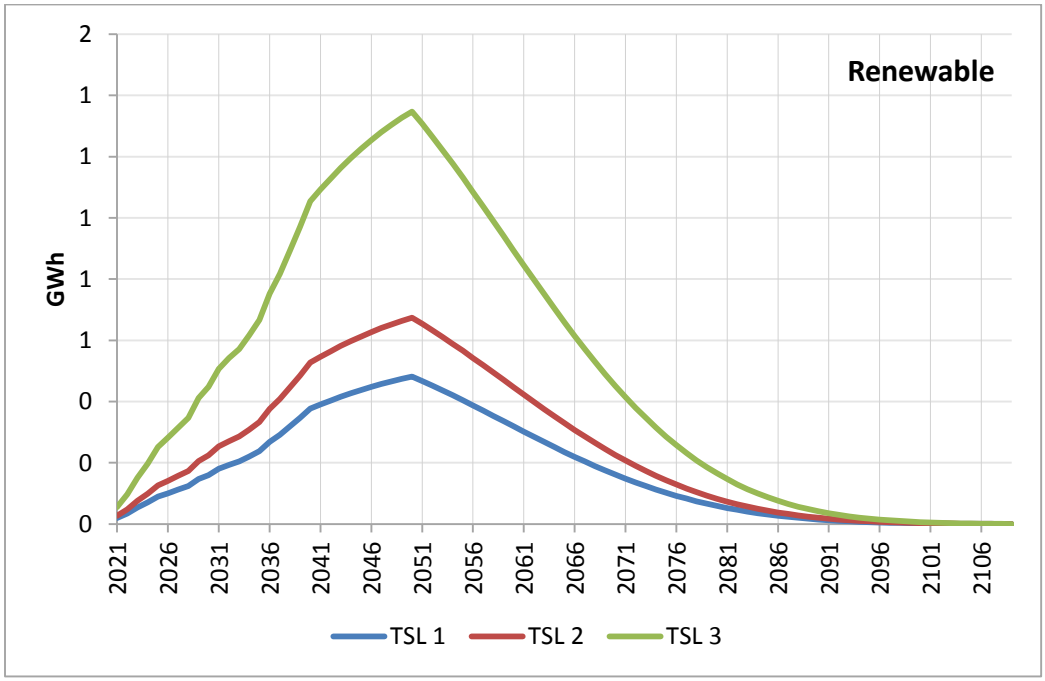

Figure 15.3.24 Renewables Generation Reduction for Standby and Off Mode Standards

15.3.3 Results Summary

Table 15.3.1 and Table 15.3.2 summarize the utility impact results estimated, respectively, for AFUE and for standby and off mode standards. Negative values indicate that capacity or generation increase.

Table 15.3.1 Summary of Utility Impact Results for AFUE Standards

	TSL				
	1	**2**	**3**	**4**	**5**
Installed Capacity Reduction (MW)					
2021	-0.018	-0.012	0.010	-3.56	-3.27
2025	-0.065	-0.013	0.094	-16.3	-14.4
2030	-0.072	0.104	0.342	-32.0	-26.5
2035	-0.078	0.209	0.579	-48.0	-38.6
2040	-0.076	0.298	0.785	-62.2	-49.1
Electricity Generation Reduction (GWh)					
2021	-0.128	-0.082	0.070	-25.6	-23.5
2025	-0.463	-0.087	0.676	-117	-103
2030	-0.444	0.647	2.13	-199	-165
2035	-0.425	1.16	3.21	-265	-214
2040	-0.373	1.50	3.94	-312	-246

Table 15.3.2 Summary of Utility Impact Results for Standby and Off Mode Standards

	TSL		
	1	**2**	**3**
Installed Capacity Reduction (MW)			
2021	0.029	0.041	0.082
2025	0.162	0.227	0.454
2030	0.349	0.489	0.977
2035	0.550	0.770	1.54
2040	0.745	1.04	2.09
Electricity Generation Reduction (GWh)			
2021	0.133	0.186	0.373
2025	0.677	0.948	1.90
2030	1.34	1.87	3.75
2035	1.94	2.72	5.44
2040	2.45	3.43	6.86

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3. Coughlin, K. *Utility Sector Impacts of Reduced Electricity Demand*. 2014. Lawrence Berkeley National Laboratory: Berkeley, CA. Report No. LBNL-6864E. (Last accessed October 15, 2015.) http://www.osti.gov/scitech/servlets/purl/1165372.

APPENDIX 15A. UTILITY IMPACT ANALYSIS METHODOLOGY

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APPENDIX 15A. UTILITY IMPACT ANALYSIS METHODOLOGY

15A.1 INTRODUCTION

In the utility impact analysis, the U.S. Department of Energy (DOE) analyzes the changes in electric installed capacity and power generation that result for each trial standard level (TSL). These changes are estimated by multiplying the site savings of electricity by a set of *impact factors* which measure the corresponding change in generation by fuel type, installed capacity, and power sector emissions. This appendix describes the methods that DOE used to calculate these impact factors. The methodology is more fully described in Coughlin (2014).[1]

DOE's analysis uses output of the DOE/Energy Information Administration (EIA)'s *Annual Energy Outlook* (*AEO*). The *AEO* includes a reference case and a set of side cases that implement a variety of economic and policy scenarios. In 2015 EIA announced the adoption of a two-year release cycle for the *AEO*, alternating between a full set of scenarios and a shorter edition containing only five scenarios. The *AEO 2015* is a shorter edition.[2] DOE adapts its calculation methodology according to the *AEO* publication type, as described below.

15A.2 METHODOLOGY

Marginal reductions in electricity demand lead to marginal reductions in power sector generation, emissions, and installed capacity. DOE quantifies these reductions using marginal impact factors, which are time series defining the change in some power sector quantity that results from a unit change in site electricity demand. Because load shapes affect the mix of generation types on the margin, these impact factors depend on end-use and sector.

DOE's approach examines a series of *AEO* side cases related to efficiency policy to estimate the relationship between marginal demand reductions and power sector variables. With EIA's two-year release cycle, the most recent full set of side cases is for *AEO 2014*. The relevant scenarios from that publication are:

- 2013 Technology (leaves all technologies at 2013 efficiencies);
- Best Available Technology (highest efficiency irrespective of cost);
- High Technology (higher penetration rates for efficiency and demand management);
- Extended Policies (includes efficiency standards that are not in the reference).

The *AEO 2015* is a shorter publication. To update the impact factors for short publication years DOE uses a two-step approach. First, DOE uses the scenarios available in both *AEO 2014* and *AEO 2015* to calculate scaling factors for each power sector variable. These scaling factors account for differences in the projected fuel mix in the two publication years. Second, DOE applies the scaling factors to the impact factors calculated using *AEO 2014*. These rescaled values are used as the impact factors for analyses based on *AEO 2015*.

For years the *AEO* full publication year, DOE uses seven steps to develop end-use dependent impact factors from results for the efficiency policy scenarios listed above. The steps are:

1. Supply-side data on generation, capacity and emissions, and demand-side data on electricity use by sector and end-use, are collected for each side case. The data are converted to differences relative to the *AEO* Reference case.

2. The changes in electricity use on the demand-side data are allocated to one of three categories: on-peak, shoulder, and off-peak. These categories are used in the utility sector to correlate end-use consumption with supply types. For each of the end-uses that are modeled explicitly in NEMS, load shape information is used to identify the fraction of annual electricity use assigned to each category. On-peak hours are defined as 12pm to 5pm Monday through Saturday, June through September. Off-peak hours are 9pm to 6am daily and all day Sunday. All other hours are assigned to the shoulder period.

3. For each year and each side case, the demand-side reductions to on-peak, off-peak and shoulder-period electricity use are matched on the supply-side to reductions in generation by fuel type. The fuel types are petroleum fuels, natural gas, renewables, nuclear and coal. The allocation is based on the following rules:

   3.1. All petroleum-based generation is allocated to peak periods;

   3.2. Natural gas generation is allocated to any remaining peak reduction; this is consistent with the fact that oil and gas steam units are used in NEMS to meet peak demand;

   3.3. Base-load generation (nuclear and coal) is allocated proportionally to all periods;

   3.4. The remaining generation of all types is allocated to the remaining off-peak and shoulder reductions proportionally.

4. The output of step 3 defines fuel-share weights giving the fraction of energy demand in each load category that is met by each fuel type, per unit of electricity demand added or subtracted at the margin, as a function of time. DOE also calculates fuel-specific marginal heat rates, equal to the primary energy (heat content) consumed per unit of electricity generated at the margin for that fuel (presented in appendix 10B).The product of the fuel-share weight and the marginal heat rate defines coefficients that allocate a marginal reduction in end-use electricity demand to a reduction in quads of fuel use for each of the five fuel types.

5. For the power sector pollutants tabulated in the *AEO* (CO_2, Hg, NO_X, SO_2). DOE uses a regression model to relate reductions in fuel consumption by fuel type to reductions in emissions of each pollutant type. The model produces a time series coefficients defining the marginal emissions intensity for each fuel type, defined as the change in mass of pollutant emitted per unit change in fuel consumption. These coefficients are combined with the weights calculated in step 4 to produce coefficients that relate emissions changes to changes in end-use demand. For power sector pollutants not tabulated in *AEO* (CH_4 and N_2O), DOE cannot define marginal emissions intensities, and instead uses Environmental Protection

Agency estimates of the average emissions intensity by fuel type.[3] These are then combined with the fuel-share weights define impact factor time series.

6. A regression model is used to relate reductions in generation by fuel type to reductions in installed capacity. The categories used for installed capacity are the same as for generation except for peak: NEMS uses two peak capacity types (combustion turbine/diesel and oil and gas steam) which are combined here into a single "peak" category. The model produces coefficients that define the change in total installed capacity of a given type resulting from a unit change in total annual generation for the corresponding fuel type. These coefficients are combined with the fuel-share weights calculated in step 4 to produce the annual impact factors relating installed capacity changes to changes in end-use demand.

7. The impact factor time-series for fuel share, pollutant emissions and capacity for the appropriate end use are multiplied by the stream of energy savings calculated in the national impact analysis (NIA) to produce estimates of the utility impacts.

This analysis ignores pumped storage, fuel cells and distributed generation, as these generation types are not affected by the policy changes modeled in the EIA side cases. The methodology is described in more detail in K. Coughlin, "Utility Sector Impacts of Reduced Electricity Demand."[1]

In the shorter *AEO*, efficiency-related scenarios are not published. For the scenarios that are published, the approach outlined above can be used to define marginal fuel-specific heat rates, to relate changes in fuel use to changes in pollutant emissions, and to relate changes in generation to changes in capacity. However, the results depend on the scenarios used as input, as the detailed evolution of the electricity sector depends both on demand and on other factors such as economic growth that affect the supply side more directly.

To deal with this issue, DOE developed a set of scaling factors derived from scenarios that are available in both *AEO 2014* and *AEO 2015* (High Economic Growth, Low Economic Growth, High Oil Price, and High Resource). Because the scaling factors are calculated using the same set of scenarios, they should be insensitive to how the scenarios are defined, and capture effects that depend only on how the projected fuel mix for electricity generation differs between the two publication years. The scaling factors are calculated as follows:

1. For both *AEO 2014* and *AEO 2015* supply-side data on generation, capacity and emissions, are collected for the side cases that are published in both years. The data are converted to differences relative to the appropriate *AEO* Reference case.

2. For each *AEO*, time series of fuel-specific marginal heat rates are defined as the ratio of change in fuel consumption to change in generation by fuel type. The values are averaged across scenarios to produce a single time series for each *AEO* edition.

3. For each *AEO*, time series of fuel-specific emissions intensities are defined as the ratio of change in pollutant emissions to change in fuel consumption for each fossil fuel type. The values are averaged across scenarios to produce a single time series for each *AEO* edition.

4. For each *AEO*, time series of fuel-specific capacity factors are defined as the ratio of change in installed capacity to change in generation by fuel type. The values are averaged across scenarios to produce a single time series for each *AEO* edition.

5. For each of the time series generated in steps 2-4 above, a scaling factor is defined as the ratio of the cumulative impact factor for 2015 divided by the cumulative impact factor for 2014. The cumulative impact factor is defined as the sum of the annual impact factors for the years 2019-2040.

6. The scaling factors are used to rescale the marginal heat rates, emissions intensities and capacity coefficients developed in the *AEO 2014* analysis, and generate impact factors corresponding to *AEO 2015*.

15A.3 MODEL RESULTS

This section summarizes the impact factors for fuel share and capacity. The marginal heat rates are presented in appendix 10B and emissions factors in appendix 13A.

15A.3.1 Electricity Generation

The data in Table 15A.3.1 show the distribution across fuel types of a unit reduction in electricity demand by sector and end-use, referred to above as fuel-share weights. The fuel types are coal, natural gas, petroleum, renewables and nuclear. The values for cooling are representative of peaking loads, while the values for refrigeration are representative of flat loads.

Table 15A.3.1 Fuel-Share Weights by Sector and End-Use (Values for 2020)

	Coal	Natural Gas	Nuclear	Oil	Renewables
Commercial Sector					
cooking	53.7%	29.6%	0.0%	0.4%	16.6%
lighting	54.1%	29.2%	0.0%	0.4%	16.6%
office equipment (non-pc)	51.7%	31.5%	0.0%	0.6%	16.6%
office equipment (pc)	51.7%	31.5%	0.0%	0.6%	16.6%
other uses	52.4%	30.8%	0.0%	0.5%	16.6%
refrigeration	56.2%	27.4%	0.0%	0.3%	16.4%
space cooling	48.9%	35.0%	0.0%	1.0%	15.4%
space heating	58.5%	24.9%	0.0%	0.0%	17.0%
ventilation	56.4%	27.3%	0.0%	0.2%	16.5%
water heating	54.3%	29.2%	0.0%	0.4%	16.4%
Industrial Sector					
all uses	52.4%	30.8%	0.0%	0.5%	16.6%
Residential Sector					
clothes dryers	55.0%	28.0%	0.0%	0.2%	17.1%
cooking	54.1%	28.6%	0.0%	0.3%	17.3%
freezers	56.1%	27.6%	0.0%	0.3%	16.4%
lighting	56.9%	26.1%	0.0%	0.1%	17.2%
other uses	55.0%	27.9%	0.0%	0.2%	17.2%
refrigeration	56.0%	27.6%	0.0%	0.3%	16.5%
space cooling	49.4%	34.3%	0.0%	0.9%	15.6%
space heating	58.1%	25.1%	0.0%	0.0%	17.1%
water heating	55.5%	27.2%	0.0%	0.2%	17.5%

15A.3.2 Installed Capacity

Table 15A.3.2 shows the total change in installed capacity (GW) per unit of site electricity demand reduction for the five principal capacity types: coal, natural gas, peaking, renewables, and nuclear. The peaking category is the sum of the two NEMS categories oil and gas steam and combustion turbine/diesel.

Table 15A.3.2 Capacity Impact Factors in GW per TWh Reduced Site Electricity Demand (Values for 2020)

	Coal	Natural Gas	Nuclear	Peaking	Renewables
Commercial Sector					
cooking	8.63E-02	1.49E-02	0.00E+00	1.19E-01	4.32E-02
lighting	8.71E-02	1.47E-02	0.00E+00	1.11E-01	4.33E-02
office equipment (non-pc)	8.31E-02	1.59E-02	0.00E+00	1.62E-01	4.33E-02
office equipment (pc)	8.31E-02	1.59E-02	0.00E+00	1.62E-01	4.33E-02
other uses	8.43E-02	1.55E-02	0.00E+00	1.46E-01	4.34E-02
refrigeration	9.05E-02	1.38E-02	0.00E+00	7.29E-02	4.28E-02
space cooling	7.87E-02	1.76E-02	0.00E+00	2.73E-01	4.01E-02
space heating	9.41E-02	1.25E-02	0.00E+00	0.00E+00	4.44E-02
ventilation	9.07E-02	1.37E-02	0.00E+00	6.89E-02	4.29E-02
water heating	8.74E-02	1.47E-02	0.00E+00	1.13E-01	4.28E-02
Industrial Sector					
all uses	8.43E-02	1.55E-02	0.00E+00	1.46E-01	4.34E-02
Residential Sector					
clothes dryers	8.85E-02	1.41E-02	0.00E+00	7.02E-02	4.46E-02
cooking	8.70E-02	1.44E-02	0.00E+00	7.97E-02	4.52E-02
freezers	9.03E-02	1.39E-02	0.00E+00	7.70E-02	4.28E-02
lighting	9.16E-02	1.32E-02	0.00E+00	2.57E-02	4.48E-02
other uses	8.84E-02	1.41E-02	0.00E+00	6.62E-02	4.49E-02
refrigeration	9.02E-02	1.39E-02	0.00E+00	7.56E-02	4.29E-02
space cooling	7.95E-02	1.73E-02	0.00E+00	2.51E-01	4.07E-02
space heating	9.35E-02	1.26E-02	0.00E+00	2.70E-03	4.47E-02
water heating	8.93E-02	1.37E-02	0.00E+00	4.32E-02	4.55E-02

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CHAPTER 16. EMPLOYMENT IMPACT ANALYSIS

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CHAPTER 16. EMPLOYMENT IMPACT ANALYSIS

16.1 INTRODUCTION

DOE's employment impact analysis is designed to estimate indirect national job creation or elimination resulting from possible standards due to reallocation of the associated expenditures for purchasing and operating residential boilers. Job increases or decreases reported in this chapter are separate from the direct boiler production sector employment impacts reported in the manufacturer impact analysis (chapter 12), and reflect the employment impact of efficiency standards on all other sectors of the economy.

16.2 ASSUMPTIONS

DOE expects energy conservation standards to decrease energy consumption, and therefore to reduce energy expenditures. The savings in energy expenditures may be spent on new investment or not at all (*i.e.*, they may remain "saved"). The standards may increase the purchase price of products, including the retail price plus sales tax, and increase installation costs.

Using an input/output econometric model of the U.S. economy, this analysis estimated the short-term effect of these expenditure impacts on net economic output and employment. DOE intends for this analysis to quantify the indirect employment impacts of these expenditure changes. It evaluated direct employment impacts at manufacturers' facilities in the manufacturer impact analysis (see chapter 12).

DOE notes that ImSET is not a general equilibrium forecasting model, and understands the uncertainties involved in projecting employment impacts, especially changes in the later years of the analysis[1] Because ImSET does not incorporate price changes, the employment effects predicted by ImSET would over-estimate the magnitude of actual job impacts over the long run for this rule. Because input/output models do not allow prices to bring markets into equilibrium, they are best used for short-run analysis. DOE therefore include a qualitative discussion of how labor markets are likely to respond in the longer term. In future rulemakings, DOE may consider the use of other modeling approaches for examining long run employment impacts.

16.3 METHODOLOGY

The Department based its analysis on an input/output model of the U.S. economy that estimates the effects of standards on major sectors of the economy related to buildings and the net impact of standards on jobs. The Pacific Northwest National Laboratory developed the model, ImSET 3.1.1[2] (Impact of Sector Energy Technologies) as a successor to ImBuild[3], a special-purpose version of the IMPLAN[4] national input/output model. ImSET estimates the employment and income effects of building energy technologies. In comparison with simple economic multiplier approaches, ImSET allows for more complete and automated analysis of the economic impacts of energy-efficiency investments in buildings.

In an input/output model, the level of employment in an economy is determined by the relationship of different sectors of the economy and the spending flows among them. Different sectors have different levels of labor intensity and so changes in the level of spending (e.g., due to the effects of an efficiency standard) in one sector of the economy will affect flows in other sectors, which affects the overall level of employment.

ImSET uses a 187-sector model of the national economy to predict the economic effects of residential and commercial buildings technologies. ImSET collects estimates of initial investments, energy savings, and economic activity associated with spending the savings resulting from standards (e.g., changes in final demand in personal consumption, business investment and spending, and government spending). It provides overall estimates of the change in national output for each input-output sector. The model applies estimates of employment and wage income per dollar of economic output for each sector and calculates impacts on national employment and wage income.

Energy-efficiency technology primarily affects the U.S. economy along three spending pathways. First, general investment funds are diverted to sectors that manufacture, install, and maintain energy-efficient products. The increased cost of products leads to higher employment in the product manufacturing sectors and lower employment in other economic sectors. Second, commercial firm and residential spending are redirected from utilities toward firms that supply production inputs. Third, electric utility sector investment funds are released for use in other sectors of the economy. When consumers use less energy, electric utilities experience relative reductions in demand which leads to reductions in utility sector investment and employment.

DOE also notes that the employment impacts estimated with ImSET for the entire economy differ from the employment impacts in the residential boiler manufacturing sector estimated in chapter 12 using the Government Regulatory Impact Model (GRIM). The methodologies used and the sectors analyzed in the ImSET and GRIM models are different.

16.4 SHORT-TERM RESULTS

The results in this section refer to impacts of residential boiler standards relative to the base case. DOE disaggregated the impact of standards on employment into three component effects: increased capital investment costs, decreased energy costs, and changes in operations and maintenance costs. DOE presents the summary impact.

Conceptually, one can consider the impact of the rule in its first year on three aggregate sectors, the residential boiler production sector, the energy generation sector, and the general consumer good sector (as mentioned above ImSET's calculations are made at a much more disaggregate level). By raising energy efficiency, the rule generally increases the purchase price of boilers; this increase in expenditures causes an increase in employment in this sector. At the same time, the improvements in energy efficiency reduce consumer expenditures on electricity, freeing up this money to be spend in other sectors. The reduction in electricity demand causes a

reduction in employment in that sector. Finally, based on the net impact of increased expenditures on boilers and reduced expenditures on electricity, consumer expenditures on everything else are either positively or negatively affected, increasing or reducing jobs in that sector accordingly. The model also captures any indirect jobs created or lost by changes in consumption due to changes in employment (as more workers are hired they consume more goods, which generates more employment, the converse is true for workers laid off).

Table 16.4.1 present the modeled net employment impact from the rule in 2021, rounded to the nearest ten jobs. Virtually all residential boilers are domestically produced, so DOE does not consider imports in this analysis. For context, the U.S. labor force had 157 million people in the first quarter of 2015[5]. DOE presents employment impacts for AFUE and stand-by power standards separately.

Table 16.4.1 Net National Short-term Change in Employment (Number of Jobs)

Standard	Trial Standard Level	2021	2025
AFUE	TSL 1	10	30
	TSL 2	30	60
	TSL 3	40	80
	TSL 4	330	110
	TSL 5	650	500
Stand-by	TSL 1	0	0
	TSL 2	0	0
	TSL 3	0	0

For context, the Office of Management and Budget (OMB) currently projects that the official unemployment rate may decline to 5.4 percent by 2019[6]. The unemployment rate in 2021 is projected to remain close to "full employment." When an economy is at full employment any effects on net employment are likely to be transitory as workers change jobs, rather than enter or exit longer-term employment.

16.5 LONG-TERM RESULTS

Over the long term DOE expects the energy savings to consumers to increasingly dominate the increase in product costs, resulting in increased aggregate savings to consumers. As a result, DOE expects demand for electricity to decline over time and demand for other goods to increase. Because the electricity generation sector is relatively capital intensive compared to the consumer goods sector, the net effect will be an increase in labor demand. In equilibrium, this should lead to upward pressure on wages and a shift in employment away from electricity generation towards consumer goods. Note that in long-run equilibrium there is no net effect on total employment because wages adjust to bring the labor market into equilibrium. Nonetheless,

even to the extent that markets are slow to adjust, DOE anticipates that net labor market impacts will in general be negligible over time due to the small magnitude of the short-term effects presented in Table 16.4.1 for most product classes and TSLs. The ImSET model projections, assuming no price or wage effects until 2025, are included in the second column of Table 16.4.1.

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CHAPTER 17. REGULATORY IMPACT ANALYSIS

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CHAPTER 17. REGULATORY IMPACT ANALYSIS

17.1 INTRODUCTION

The U.S. Department of Energy (DOE) has determined that the regulatory action described in the Federal Register notice associated with this TSD constitutes an "economically significant regulatory action" under Executive Order (E.O.) 12866, Regulatory Planning and Review. 58 FR 51735 (October 4, 1993). For such actions, E.O. 12866 requires Federal agencies to provide "an assessment, including the underlying analysis, of costs and benefits of potentially effective and reasonably feasible alternatives to the planned regulation, identified by the agencies or the public (including improving the current regulation and reasonably viable non-regulatory actions), and an explanation why the planned regulatory action is preferable to the identified potential alternatives." 58 FR 51735, 51741.

To conduct this analysis, DOE used an integrated National Impact Analysis (NIA)-RIA model built on a modified[a] version of the NIA model DOE used to assess the benefits from AFUE Standards, as discussed in Chapter 10. DOE identified five non-regulatory policy alternatives that possibly could provide incentives for the same energy efficiency levels as the ones in the proposed trial standard levels for the residential boilers that are the subject of this rulemaking. The non-regulatory policy alternatives are listed in Table 17.1.1, which also includes the "no new regulatory action" alternative. DOE evaluated each alternative in terms of its ability to achieve significant energy savings at a reasonable cost, and compared the effectiveness of each to the effectiveness of the proposed standards for the two product classes of residential boilers covered by this RIA: gas-fired hot water residential boilers and oil-fired hot water residential boilers.[b]

Table 17.1.1 Non-Regulatory Alternatives to National Standards

No New Regulatory Action
Consumer Rebates
Consumer Tax Credits
Manufacturer Tax Credits
Voluntary Energy Efficiency Targets
Bulk Government Purchases

Sections 17.2 and 17.3 discuss the analysis of five selected policies listed in Table 17.1.1 (excluding the alternative of "No New Regulatory Action"). Section 17.4 presents the results of the policy alternatives.

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[a] For this RIA, DOE developed an alternative NIA model that accounts for shipments only to the residential sector, as this is the sector that represents most of the market for this equipment. In addition, the alternative NIA does not account for repairs and does not include any rebound effect when calculating energy savings. DOE believes that the national benefits from standards calculated this way are more comparable to the benefits from the alternative policies.

[b] Forecasted shipments of gas-fired and oil-fired steam residential boilers do not make up a large enough percentage of shipments to warrant analysis in this RIA.

17.2 NON-REGULATORY POLICIES

This section describes the method DOE used to analyze the energy savings and cost effectiveness of the non-regulatory policy alternatives for residential boilers. This section also describes the assumptions underlying the analysis.

17.2.1 Methodology

DOE used its integrated NIA-RIA spreadsheet model to calculate the national energy savings (NES) and net present value (NPV) associated with each non-regulatory policy alternative. Chapter 10 of the technical support document (TSD) describes the NIA spreadsheet model. Appendix 17A discusses the NIA-RIA integrated model approach.

DOE quantified the effect of each alternative on the purchase of products that meet the efficiency levels corresponding to each TSL. After establishing the quantitative assumptions underlying each alternative, DOE appropriately revised inputs to the NIA-RIA spreadsheet model. The primary model inputs revised were market shares of equipment meeting the target efficiency levels set for each TSL. The shipments of equipment for any given year reflect a distribution of efficiency levels. DOE assumed, for each TSL, that new energy efficiency standards would affect 100 percent of the shipments of products that did not meet the TSL target levels in the no-new-standards case,[c] whereas the non-regulatory policies would affect a smaller percentage of those shipments. DOE made certain assumptions about the percentage of shipments affected by each alternative policy. DOE used those percentages to calculate the shipment-weighted average energy consumption and costs of residential boilers attributable to each policy alternative.

Increasing the efficiency of a product often increases its average installed cost. However, operating costs generally decrease because energy consumption declines. DOE therefore calculated an NPV for each non-regulatory alternative in the same way it did for the proposed standards. In some policy scenarios, increases in total installed cost are mitigated by government rebates or tax credits. Because DOE assumed that consumers would re-pay credits and rebates in some way (such as additional taxes), DOE did not include rebates or tax credits as a consumer benefit when calculating national NPV. DOE's analysis also excluded any administrative costs for the non-regulatory policies; including such costs would decrease the NPVs slightly.

The following are key measures for evaluating the impact of each alternative.

- National Energy Savings (NES), given in quadrillion Btus (quads), describes the cumulative national energy saved over the lifetime of equipment purchased during the 30-year analysis period starting in the effective date of the policy (2021-2050).
- Net Present Value (NPV), represents the value of net monetary savings in 2015, expressed in 2014$, from equipment purchased during the 30-year analysis period starting in the effective date of the policy (2021-2050). DOE calculated the NPV as the difference between the present values of installed equipment cost and operating

[c] The no-new-standards case for the NIA is a market-weighted average energy efficiency calculated from units at several efficiency levels.

expenditures in the no-new-standards case and the present values of those costs in each policy case. DOE calculated operating expenses (including energy costs) for the life of the product.

17.2.2 Assumptions Regarding Non-Regulatory Policies

The effects of non-regulatory policies are by nature uncertain because they depend on program implementation, marketing efforts, and on consumers' response to a program. Because the projected effects depend on assumptions regarding the rate of consumer participation, they are subject to more uncertainty than are the impacts of mandatory standards, which DOE assumes will be met with full compliance. To increase the robustness of the analysis, DOE conducted a literature review regarding each non-regulatory policy and consulted with recognized experts to gather information on similar incentive programs that have been implemented in the United States. By studying experiences with the various types of programs, DOE sought to make credible assumptions regarding potential market impacts. Section 17.3 presents the sources DOE relied on in developing assumptions about each alternative policy and reports DOE's conclusions as they affected the assumptions that underlie the modeling of each alternative policy.

Each non-regulatory policy that DOE considered would improve the average efficiency of new residential boilers relative to their no-new-standards case efficiency scenario (which involves no new regulatory action). The analysis considered that each alternative policy would induce consumers to purchase units having the same technology as required by standards (the target level), according to the minimum energy efficiency set for each TSL. As opposed to the standards case, however, the policy cases may not lead to 100 percent market penetration of units that meet the target level.

Table 17.1.2 shows the energy efficiencies from the technologies stipulated for residential boilers for each TSL.

Table 17.1.1 Energy Efficiency by TSL (AFUE, %)

	TSL 1	TSL 2	**TSL 3**	TSL 4	TSL 5
Gas-Fired Hot Water Residential Boiler	83%	83%	**84%**	90%	96%
Oil-Fired Hot Water Residential Boiler	85%	86%	**86%**	91%	91%

DOE assumed that the effects of non-regulatory policies would last from the effective date of standards—2021—through the end of the analysis period, which is 2050.

17.2.3 Policy Interactions

DOE calculated the effects of each non-regulatory policy separately from those of the other policies. In practice, some policies are most effective when implemented in combination, such as voluntary efficiency targets implemented with consumer rebates or tax credits. However, DOE attempted to make conservative assumptions to avoid double-counting policy impacts. The resulting policy impacts are therefore not additive, and the combined effect of several or all policies cannot be inferred from summing their results.

Section 17.4 presents graphs that show the market penetration estimated under each non-regulatory policy for residential boilers.

17.3 NON-REGULATORY POLICY ASSUMPTIONS

The following subsections describe DOE's analysis of the impacts of the five non-regulatory policy alternatives to the standards proposed for residential boilers. (Because the alternative of "No New Regulatory Action" has no energy or economic impacts, essentially representing the NIA no-new-standards case, DOE did not perform any additional analysis for that alternative.) DOE developed estimates of the market penetration of more efficient products both with and without each of the non-regulatory policy alternatives.

17.3.1 No New Regulatory Action

The case in which no new regulatory action is taken with regard to the energy efficiency of residential boilers constitutes the no-new-standards case, as described in Chapter 10, National Impact Analysis. The no-new-standards case provides the basis of comparison for all other policies. By definition, no new regulatory action yields zero NES and an NPV of zero dollars.

17.3.2 Consumer Rebates

DOE considered the scenario in which the Federal government would provide financial incentives in the form of rebates to consumers for purchasing energy-efficient equipment. This policy provides a consumer rebate for purchasing residential boilers that operate at the same efficiency levels as stipulated in each TSL.

17.3.2.1 Methodology

DOE based its evaluation methodology for consumer rebates on a comprehensive study of California's potential for achieving energy efficiency. The study, performed by XENERGY, Inc.,[d] summarized experiences with various utility rebate programs.[1] XENERGY's analytical method utilized graphs, or penetration curves, that estimate the market penetration of a technology based on its benefit/cost (B/C) ratio. DOE consulted with experts and reviewed other methods of estimating the effect of consumer rebate programs on the market penetration of efficient technologies. The other methods, developed after the referenced XENERGY report was published,[2, 3, 4, 5, 6, 7] used different approaches: other economic parameters (e.g., payback period), expert surveys, or model calibration based on specific utility program data rather than multi-utility data. Some models in use by energy efficiency program evaluation experts were so client-specific that generic relationships between economic parameters and consumer response could not be established.[5] DOE decided that the most appropriate available method for this RIA was the XENERGY approach of penetration curves based on B/C ratio, which incorporates lifetime operating cost savings.

XENERGY's model estimates market impacts induced by financial incentives based on the premise that two types of information diffusion drive the adoption of new technologies.

[d] XENERGY is now owned by KEMA, Inc. (www.kema.com)

Internal sources of information encourage consumers to purchase new equipment primarily through word-of-mouth from early adopters. *External sources* affect consumer purchase decisions through marketing efforts and information from outside the consumer group. Appendix 17A contains additional details on internal and external information diffusion.

XENERGY's model equation accounts for the influences of both internal and external sources of information by superimposing the two components. Combining the two mechanisms for information diffusion, XENERGY's model generates a set of penetration (or implementation) curves for a policy measure. XENERGY calibrated the curves based on participation data from utility rebate programs. The curves illustrate the increased penetration (i.e., increased market share) of efficient equipment driven by consumer response to changes in B/C ratio induced by rebate programs. The penetration curves depict various diffusion patterns based on perceived market barriers (from no-barriers to extremely-high-barriers) to consumer purchase of high-efficiency equipment. DOE adjusted the XENERGY former penetration curves based on expert advice founded on more recent utility program experience.[5, 8]

DOE modeled the effects of a consumer rebate policy for residential boilers by determining, for each TSL, the increase in market penetration of equipment meeting the target level relative to their market penetration in the no-new-standards case. It used the interpolation method presented in Blum et al (2011)[9] to create customized penetration curves based on relationships between actual no-new-standards case market penetrations and actual B/C ratios. To inform its estimate of B/C ratios provided by a rebate program DOE performed a thorough nationwide search for existing rebate programs for residential boilers. It gathered data on utility or agency rebates throughout the nation for this equipment, and used this data to calibrate the customized penetration curves it developed for each product class covered by this RIA so they can best reflect the market barrier levels that consumer rebates for residential boilers would face. Section 17.3.2.2 shows the resulting interpolated curves used in the analysis.

17.3.2.2 Analysis

DOE estimated the effect of increasing the B/C ratio of residential boilers via a rebate that would pay, depending on the product class and TSL, all or part of the increased installed cost of units that meet the target efficiency levels compared to units meeting the baseline efficiency level.[e] To inform its estimate of an appropriate rebate amount, DOE performed a thorough nationwide search for existing rebate programs for residential boilers in April, 2014. It gathered data from a sample of utility and agency rebate programs that includes 117 rebates for residential boilers initiated by 57 utilities or agencies in various States. DOE then estimated a market representative rebate value for each product class covered by this RIA which it applied in the calculation of the B/C ratio of residential boilers under the effect of consumer rebates. (Appendix 17A identifies the rebate programs and details the methodology DOE used to estimate a market representative rebate amount.) DOE assumed that rebates would remain in effect at the same level throughout the forecast period (2021-2050).

[e] The baseline technology is defined in the engineering analysis, Chapter 5, as the technology that represents the basic characteristics of residential boilers. A baseline unit typically is one that just meets current Federal energy conservation standards and provides basic consumer utility.

DOE first calculated the B/C ratio of a residential boiler without a rebate using the difference in total installed costs (C) and lifetime operating cost savings[f] (B) between a unit meeting the target level and a baseline unit. It then calculated the B/C ratio given a rebate for the unit meeting the target efficiency level. Because the rebate reduced the incremental cost, the unit receiving the rebate had a larger B/C ratio. Table 17.3.1 shows the effect of consumer rebates for each TSL on the B/C ratio of residential boilers shipped in the first year of the analysis period.

Table 17.3.1 Benefit/Cost Ratios Without and With Rebates for Residential Boilers

	TSL 1	TSL 2	**TSL 3**	TSL 4	TSL 5
Gas-Fired Hot Water Residential Boiler					
B/C Ratio Without Rebate	10.1	10.1	**10.0**	1.3	0.9
Rebate Amount (2014$)	164.79	164.79	**228.50**	610.76	993.02
B/C Ratio With Rebate	infinite	infinite	**infinite**	4.2	2.0
Estimated Market Barriers	High	High	**High**	Low-Mod	Mod
Oil-Fired Hot Water Residential Boiler					
B/C Ratio Without Rebate	1.8	2.1	**2.1**	0.6	0.6
Rebate Amount (2014$)	379.60	469.84	**469.84**	1100.34	1100.34
B/C Ratio With Rebate	infinite	infinite	**infinite**	1.1	1.1
Estimated Market Barriers	Low-Mod	Low	**Low**	Low-Mod	Low-Mod

* Mod: Moderate market barriers; Low-Mod: Low-to-Moderate market barriers.

DOE used the B/C ratio along with the customized penetration curves shown in Figure 17.3.1 to estimate the percentage of consumers who would purchase residential boilers that meet the target levels both with and without a rebate incentive. The estimated levels of market barriers corresponding to the penetration curves DOE calculated to represent the market behavior for residential boilers at the selected TSL are indicated (highlighted) in Table 17.3.1. DOE assumed the estimated market barriers would remain the same over the whole analysis period.

[f] The cash flow of the operating cost savings is discounted to the purchase year using a 7 percent discount rate.

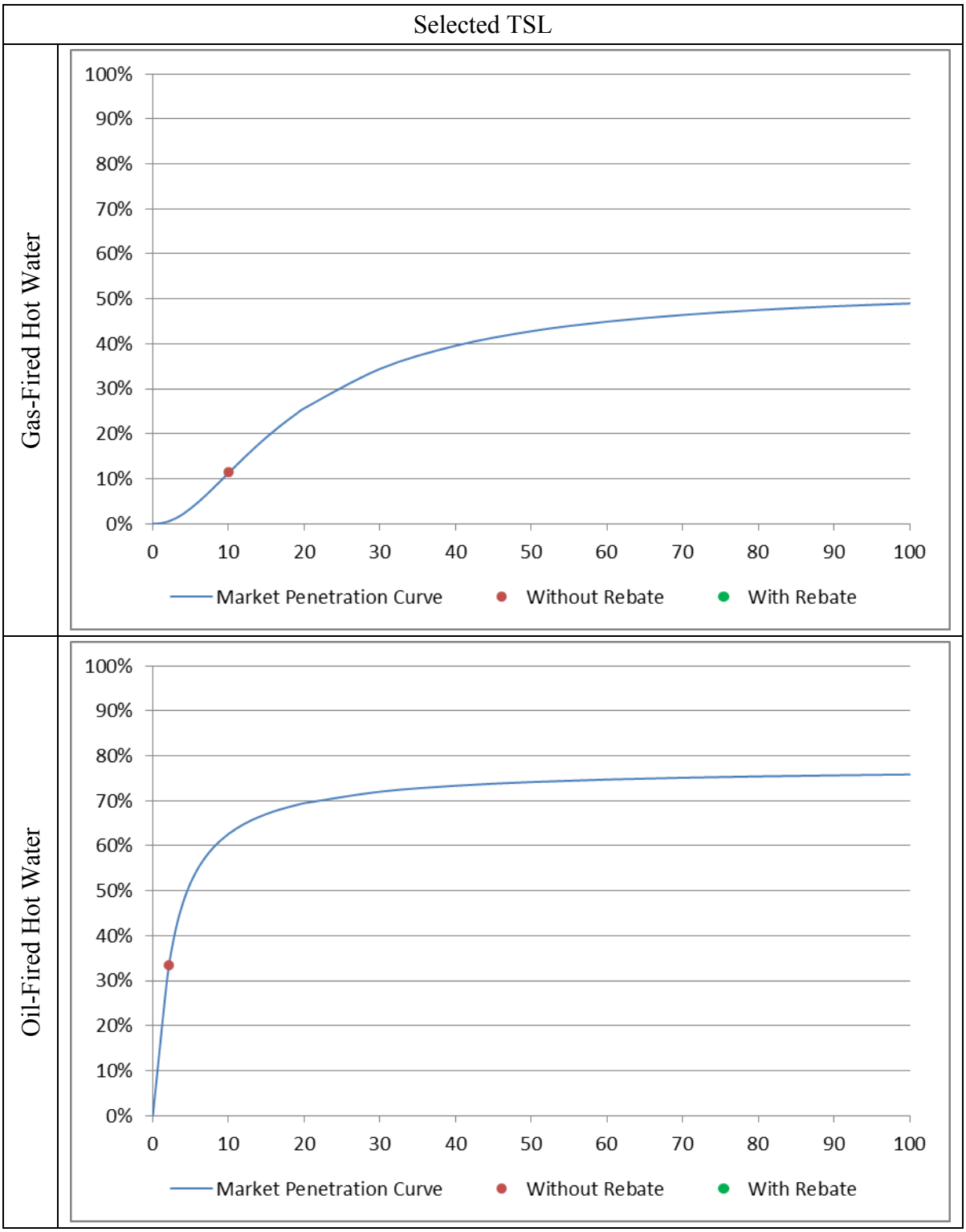

Figure 17.3.1 Market Penetration Curves for Residential Boilers[g]

[g] Because the B/C ratio with rebates at the selected TSL is infinite for both product classes (see Table 17.3.1), the data points that refer to the market penetration with rebates are not shown in either of the two charts.

DOE next estimated the percent increase represented by the change in penetration rate shown on the corresponding penetration curve. It then added this percent increase to the market share of units that meet the target level in the no-new-standards case to obtain the market share of units that meet the target level in the rebate policy case.

Table 17.3.2 summarizes DOE's assumptions for residential boilers regarding the market penetration of products in 2021 that meet the target levels at each TSL given a consumer rebate.

Table 17.3.2 Market Penetrations in 2021 Attributable to Consumer Rebates

	TSL 1	TSL 2	**TSL 3**	TSL 4	TSL 5
Gas-Fired Hot Water Residential Boiler					
Base-Case Market Share	7.6%	7.6%	**11.3%**	11.2%	1.2%
Policy Case Market Share	30.4%	30.4%	**41.7%**	37.8%	5.7%
Increased Market Share	22.8%	22.8%	**30.4%**	26.6%	4.5%
Oil-Fired Hot Water Residential Boiler					
Base-Case Market Share	18.5%	33.4%	**33.4%**	3.9%	3.9%
Policy Case Market Share	62.7%	77.6%	**77.6%**	10.2%	10.2%
Increased Market Share	44.2%	44.2%	**44.2%**	6.3%	6.3%

DOE used the resulting annual increases in market shares as inputs to represent the rebate policy case scenario in its NIA-RIA model. Appendix 17A shows the annual market share increases due to this policy for the whole forecast period. Section 17.4 presents the resulting market penetration trends for the policy case of consumer rebates for residential boilers.

17.3.3 Consumer Tax Credits

DOE estimated the effects of tax credits on consumer purchases based on its previous analysis of consumer participation in tax credits. DOE supported its approach using data from Oregon State's tax credit program for energy-efficient appliances. DOE also incorporated previous research that disaggregated the effect of rebates and tax credits into a *direct price effect*, which derives from the savings in purchase price, and an *announcement effect*, which is independent of the amount of the incentive.[10, 11] The announcement effect derives from the credibility that a technology receives from being included in an incentive program, as well as changes in product marketing and modifications in markup and pricing. DOE assumed that the rebate and consumer tax credit policies would encompass both direct price effects and announcement effects, and that half the increase in market penetration associated with either policy would be due to the direct price effect and half to the announcement effect.

In estimating the effects of a tax credit on purchases of consumer products that meet new efficiency standards, DOE assumed the amount of the tax credit would be the same as the corresponding rebate amount discussed above.

DOE estimated that fewer consumers would participate in a tax credit program than would take advantage of a rebate. Research has shown that the delay required for a consumer to receive a tax credit, plus the added time and cost in preparing the tax return, make a tax credit incentive less effective than a rebate received at the time of purchase. Based on previous

analyses, DOE assumed that only 60 percent of the consumers who would take advantage of a rebate would take advantage of a tax credit.[12]

In preparing its assumptions to estimate the effects of tax credits on consumer purchases of residential boilers, DOE also reviewed other tax credit programs that have been offered at both the Federal and State levels for energy-efficient appliances.

The Energy Policy Act of 2005 (EPACT 2005) included Federal tax credits for consumers who purchase energy-efficient products.[13] Those tax credits were in effect in 2006 and 2007, expired in 2008, were reinstated for 2009–2010 by the American Recovery and Reinvestment Act of 2009 (ARRA), extended by Congress for 2011 with some modifications, and expired at the end of 2011.[14, 15] The American Taxpayer Relief Act of 2012 extended, with some modifications, residential tax credits for air conditioners, heat pumps, furnaces, and water heaters placed in service between January 1, 2012 and December 31, 2013.[16] DOE reviewed Internal Revenue Service data on the numbers of taxpayers who claimed the tax credits during tax years 2006 and 2007. DOE also reviewed data from an earlier Federal energy conservation tax credit program in place in the 1980s. However, DOE did not find data specific enough to residential boilers to warrant adjusting its analysis method for the Consumer Tax Credits policy case. Appendix 17A contains more information on Federal consumer tax credits.

DOE also reviewed its previous analysis of Oregon's tax credits for clothes washers to provide support for its assumptions.[17] In that previous analysis, DOE compared the market shares of ultra-high efficiency (UHE) residential clothes washers in Oregon, which offered both State tax credits and utility rebates, with those in Washington State, which offered only utility rebates during the same period. Based on this analysis, DOE estimated that in Oregon the impact of tax credits was 62 percent of the impact of rebates for UHE clothes washers having equivalent efficiency. This finding supports its original assumption that participation in a tax credit program would be about 60 percent of participation in a rebate program. Additional discussion of State tax credits for Oregon and other states is in Appendix 17A.

DOE applied the assumed 60 percent participation described above to the increase in penetration rates estimated for the rebate policy to estimate penetration rates attributable to consumer tax credits. In doing so, DOE incorporated the assumptions for consumer response to financial incentives from the customized penetration curves it developed for residential boilers (See Figure 17.3.1).

Table 17.3.3 summarizes DOE's assumptions for residential boilers regarding the market penetration of products in 2021 that meet the target levels at each TSL given a consumer tax credit.

Table 17.3.3 Market Penetrations in 2021 Attributable to Consumer Tax Credits

	TSL 1	TSL 2	**TSL 3**	TSL 4	TSL 5
Gas-Fired Hot Water Residential Boiler					
Base-Case Market Share	7.6%	7.6%	**11.3%**	11.2%	1.2%
Policy Case Market Share	21.3%	21.3%	**29.5%**	27.2%	3.9%
Increased Market Share	13.7%	13.7%	**18.2%**	16.0%	2.7%
Oil-Fired Hot Water Residential Boiler					
Base-Case Market Share	18.5%	33.4%	**33.4%**	3.9%	3.9%
Policy Case Market Share	45.0%	59.9%	**59.9%**	7.7%	7.7%
Increased Market Share	26.5%	26.5%	**26.5%**	3.8%	3.8%

The increased market shares attributable to consumer tax credits shown in Table 17.3.3 were used as inputs in the NIA-RIA model. Appendix 17A shows the annual market share increases due to this policy for the whole forecast period. Section 17.4 presents the resulting market penetration trends for the policy case of consumer tax credits for residential boilers that meet the efficiency level for the selected TSL.

17.3.4 Manufacturer Tax Credits

To analyze the potential effects of a policy that offers tax credits to manufacturers that produce residential boilers that meet the target efficiency levels at each TSL, DOE assumed that a manufacturer tax credit would lower the consumer's purchase cost by an amount equivalent to that provided by the consumer rebates or tax credits described above. DOE further assumed that manufacturers would pass on some of their reduced costs to consumers, causing a direct price effect. DOE assumed that no announcement effect would occur, because the program would not be visible to consumers.[h] Because the direct price effect is approximately equivalent to the announcement effect,[10] DOE estimated that a manufacturer tax credit would induce half the number of consumers assumed to take advantage of a consumer tax credit to purchase more efficient products. Thus the assumed participation rate is equal to 30 percent of the number of consumers who would participate in a rebate program.

DOE attempted to investigate manufacturer response to the Energy Efficient Appliance Credits for manufacturers mandated by EPACT 2005.[18] Those manufacturer tax credits have been in effect for dishwashers, clothes washers and refrigerators produced beginning in 2009. DOE was unable to locate data from the Internal Revenue Service or other sources on manufacturer response to the Federal credits. Appendix 17A presents details on Federal manufacturer tax credits.

DOE applied the assumption of 30 percent participation to the increase in penetration rates predicted for the rebate policy to estimate the effects of a manufacturer tax credit policy. In

[h] Note that this is a conservative assumption, since it is possible that manufacturers or utility/agency efficiency programs might promote the models for which manufacturers increase production due to the tax credits, which in turn might induce some announcement effect. However, DOE found no data on such programs on which to base an estimate of the magnitude of this possible announcement effect on consumer behavior.

doing so, DOE incorporated the assumptions for consumer response to financial incentives from the customized penetration curves it developed for residential boilers. (See Figure 17.3.1).

Table 17.3.4 summarizes DOE's assumptions for residential boilers regarding the market penetration of products in 2021 that meet the target levels at each TSL given a manufacturer tax credit.

Table 17.3.4 Market Penetrations in 2021 Attributable to Manufacturer Tax Credits

	TSL 1	TSL 2	**TSL 3**	TSL 4	TSL 5
Gas-Fired Hot Water Residential Boiler					
Base-Case Market Share	7.6%	7.6%	**11.3%**	11.2%	1.2%
Policy Case Market Share	14.4%	14.4%	**20.4%**	19.2%	2.5%
Increased Market Share	6.8%	6.8%	**9.1%**	8.0%	1.3%
Oil-Fired Hot Water Residential Boiler					
Base-Case Market Share	18.5%	33.4%	**33.4%**	3.9%	3.9%
Policy Case Market Share	31.8%	46.6%	**46.6%**	5.8%	5.8%
Increased Market Share	13.3%	13.3%	**13.3%**	1.9%	1.9%

The increased market shares attributable to a manufacturer tax credit shown in Table 17.3.4 were used as inputs in the NIA-RIA model. Appendix 17A shows the annual market share increases due to this policy for the whole forecast period. Section 17.4 presents the resulting market penetration trends for the policy case of manufacturer tax credits for residential boilers.

17.3.5 Voluntary Energy Efficiency Targets

DOE assumed that voluntary energy efficiency targets would lead manufacturers of residential boilers to gradually stop producing units that operate below the efficiency levels set for each TSL. DOE assumed that the impetus for phasing out production of low-efficiency units would be a program with impacts similar to those of the ENERGY STAR labeling program conducted by the Environmental Protection Agency (EPA) and DOE in conjunction with industry partners. The ENERGY STAR program specifies the minimum energy efficiencies that various products must have to receive the ENERGY STAR label. ENERGY STAR encourages consumers to purchase efficient products via marketing that promotes consumer label recognition, various incentive programs that adopt the ENERGY STAR specifications, and manufacturers' promotion of their qualifying appliances. ENERGY STAR projects market penetration of compliant appliances and estimates the percentage of sales of compliant appliances that are attributable to the ENERGY STAR program.

Researchers have analyzed the ENERGY STAR program's effects on sales of several consumer products. Program efforts generally involve a combination of information dissemination and utility or agency rebates. The analyses have been based on State-specific data on percentages of shipments of various appliances that meet ENERGY STAR specifications. The analyses generally have concluded that the market penetration of ENERGY STAR-qualifying appliances is higher in regions or States where ancillary promotional programs have been active.[19, 20, 21]

DOE believes that informational incentive programs – like ENERGY STAR, or any other labeling program sponsored by industry or other organizations – are likely to reduce the market barriers to more efficient products over time. During the rebate analysis, when assessing the B/C ratio and market penetration in the no-new-standards case for residential boilers, DOE observed that the level of market barriers for residential boilers meeting the target level of the selected TSL is high for gas-fired residential boilers, and low for oil-fired residential boilers. DOE estimates that voluntary energy efficiency targets could reduce these barriers to lower levels over 10 years. Table 17.3.5 presents the levels of market barriers DOE estimated for residential boilers in the no-new-standards case and in the policy case of voluntary energy efficiency targets. DOE followed the methodology presented by Blum et al (2011)[9] to evaluate the effects that such a reduction in market barriers would have on the market penetration of efficient residential boilers.[i] The methodology relies on interpolated market penetration curves to calculate – given a B/C ratio – how the market penetration of more efficient units increases as the market barrier level to those units decreases.

Table 17.3.5 Market Barriers Changes Attributable to Voluntary Energy Efficiency Targets (TSL 3)

	No-New-Standards Case	Voluntary Energy Efficiency Targets
Gas-Fired Hot Water Residential Boiler	High	Moderate-to-High
Oil-Fired Hot Water Residential Boiler	Low	No

Table 17.3.6 summarizes DOE's assumptions for residential boilers regarding the market penetration of products in 2021 that meet the target levels at each TSL given voluntary energy efficiency targets. Table 17.3.7 expands on Table 17.3.6 to include, for the selected TSL, DOE's assumptions regarding the market penetration of units in selected years.

Table 17.3.6 Market Penetrations in 2021 Attributable to Voluntary Energy Efficiency Targets

	TSL 1	TSL 2	**TSL 3**	TSL 4	TSL 5
Gas-Fired Hot Water Residential Boiler					
Base-Case Market Share	7.6%	7.6%	**11.3%**	11.2%	1.2%
Policy Case Market Share	9.0%	9.0%	**12.4%**	13.0%	1.3%
Increased Market Share	1.4%	1.4%	**1.0%**	1.8%	0.2%
Oil-Fired Hot Water Residential Boiler					
Base-Case Market Share	18.5%	33.4%	**33.4%**	3.9%	3.9%
Policy Case Market Share	20.6%	35.2%	**35.2%**	4.6%	4.6%
Increased Market Share	2.0%	1.9%	**1.9%**	0.7%	0.7%

[i] For the calculation of B/C ratios DOE discounted the cash flow of the operating cost savings to the purchase year using a 7 percent discount rate.

Table 17.3.7 Market Penetrations in Selected Years Attributable to Voluntary Energy Efficiency Targets for TSL 3

	2021	2030	2050
Gas-Fired Hot Water Residential Boiler			
Base-Case Market Share	11.3%	9.8%	6.4%
Policy Case Market Share	12.4%	22.5%	23.6%
Increased Market Share	1.0%	12.7%	17.2%
Oil-Fired Hot Water Residential Boiler			
Base-Case Market Share	33.4%	33.0%	32.0%
Policy Case Market Share	35.2%	67.6%	71.1%
Increased Market Share	1.9%	34.7%	39.1%

The increased market shares attributable to voluntary energy efficiency targets shown in Table 17.3.6 were used as inputs in the NIA-RIA model. Appendix 17A shows the annual market share increases due to this policy for the whole forecast period. Section 17.4 presents the resulting market penetration trends for the policy case of voluntary energy efficiency targets for residential boilers that meet the efficiency level for the selected TSL.

17.3.6 Bulk Government Purchases

Bulk government purchases can lead to Federal, State, and local governments purchasing large quantities of products that meet a certain, target efficiency level. Combining the market demands of multiple public sectors can provide a market signal to manufacturers and vendors that some of their largest customers seek products that meet an efficiency target at favorable prices. Such a program also can induce “market pull,” whereby manufacturers and vendors would achieve economies of scale for high efficiency products.

Most of the previous bulk government purchase (procurement) initiatives at the Federal, State, and municipal levels have not tracked data on numbers of purchases or degree of compliance with procurement specifications. In many cases, procurement programs are decentralized, being part of larger State or regional initiatives. DOE based its assumptions regarding the effects of this policy on studies the Federal Energy Management Program (FEMP) performed regarding the savings potential of its procurement specifications for appliances and other products. FEMP, however, does not track purchasing data, because of the complex range of purchasing systems, large number of vendors, and so on. States, counties, and municipalities have demonstrated increasing interest and activity in “green purchasing." Although many of the programs target office equipment, the growing infrastructure for developing and applying efficient purchasing specifications indicates that bulk government purchase programs are feasible.[22, 23]

DOE assumed that government agencies would administer bulk purchasing programs for residential boilers. At the federal level, this type of program could modify the current FEMP procurement guidelines for residential boilers, which refer to the ENERGY STAR requirements for residential boilers.[24] DOE reviewed its own previous research on the potential for market transformation through bulk government purchases. Its major study analyzed several scenarios based on the assumption that 20 percent of Federal equipment purchases in 2000 already incorporated energy efficiency requirements based on FEMP guidelines. One scenario in the

DOE report showed energy efficient purchasing ramping up during 10 years from 20 percent to 80 percent of all Federal purchases.[25] Based on this study, DOE estimated that a bulk government purchase program instituted within a 10-year period would result in at least 80 percent of government-purchased residential boilers meeting the target efficiency level.

DOE assumed that bulk government purchases would affect a subset of federal government-owned residential buildings heated by residential boiler.[j] DOE used the 2009 Residential Energy Consumption Survey (RECS 2009)[26] to calculate the share of buildings heated by residential boilers that corresponds to federal government-owned buildings. The calculation resulted in 8.3 percent for gas-fired hot water boilers and 3.2 percent for oil-fired hot water boilers. DOE assumed these percentages as the shares of the market to which this policy would apply.

DOE estimated that starting in 2021, each year of a bulk government purchase policy would result in an increasing percent of shipments of government-purchased units beyond the no-new-standards case that would meet the target efficiency level. DOE estimated that within 10 years (by 2030) bulk government purchasing programs would result in 80 percent[k] of the market for residential boilers used in federal government-owned residential buildings meeting the target level. DOE modeled the bulk government purchase program assuming that the market share for residential boilers achieved in 2030 would be at least maintained throughout the rest of the forecast period.

Table 17.3.8 summarizes DOE's assumptions for residential boilers regarding the market penetration of products in 2021 that meet the target levels at each TSL given bulk government purchases.

Table 17.3.8 Market Penetrations in 2021 Attributable to Bulk Government Purchases

	TSL 1	TSL 2	**TSL 3**	TSL 4	TSL 5
Gas-Fired Hot Water Residential Boiler					
Base-Case Market Share	7.6%	7.6%	**11.3%**	11.2%	1.2%
Policy Case Market Share	7.8%	7.8%	**11.5%**	11.5%	1.8%
Increased Market Share	0.2%	0.2%	**0.2%**	0.3%	0.7%
Oil-Fired Hot Water Residential Boiler					
Base-Case Market Share	18.5%	33.4%	**33.4%**	3.9%	3.9%
Policy Case Market Share	18.7%	33.5%	**33.5%**	4.1%	4.1%
Increased Market Share	0.1%	0.1%	**0.1%**	0.2%	0.2%

The increased market shares attributable to bulk government purchases shown in Table 17.3.8 were used as inputs in the NIA-RIA model. Appendix 17A shows the annual market share increases due to this policy for the whole forecast period. Section 17.4 presents the resulting

[j] Because this RIA account for shipments only to the residential sector, DOE did not evaluate the impacts of this alternative policy on federal government-owned commercial buildings.
[k] The 80 percent target to be achieved within 10 years may not be reached, as it is constrained by the market share below the target level in the no-new-standards case scenario.

market penetration trends for the policy case of bulk government purchases for residential boilers.

17.4 IMPACTS OF NON-REGULATORY ALTERNATIVES

Figure 17.4.1 and Figure 17.4.2 show the effects of each non-regulatory policy alternative on the market penetration of more efficient residential boilers. Relative to the no-new-standards case, the alternative policy cases increase the market shares that meet the target level. Recall the proposed/selected standards (not shown in the figures) would result in a 100-percent market penetration of products that meet the more efficient technology.

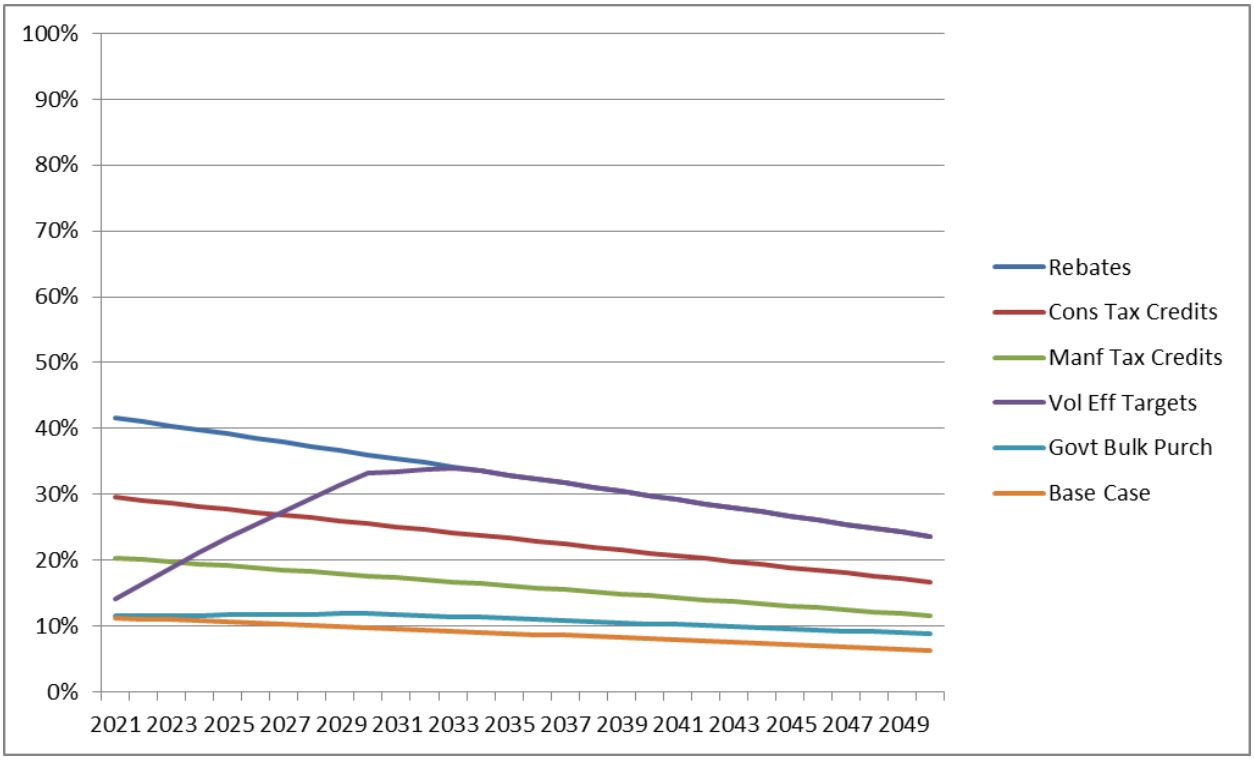

Figure 17.4.1 Market Penetration of Gas-Fired Hot Water Residential Boilers Meeting the Target Level in Policy Cases (TSL 3)

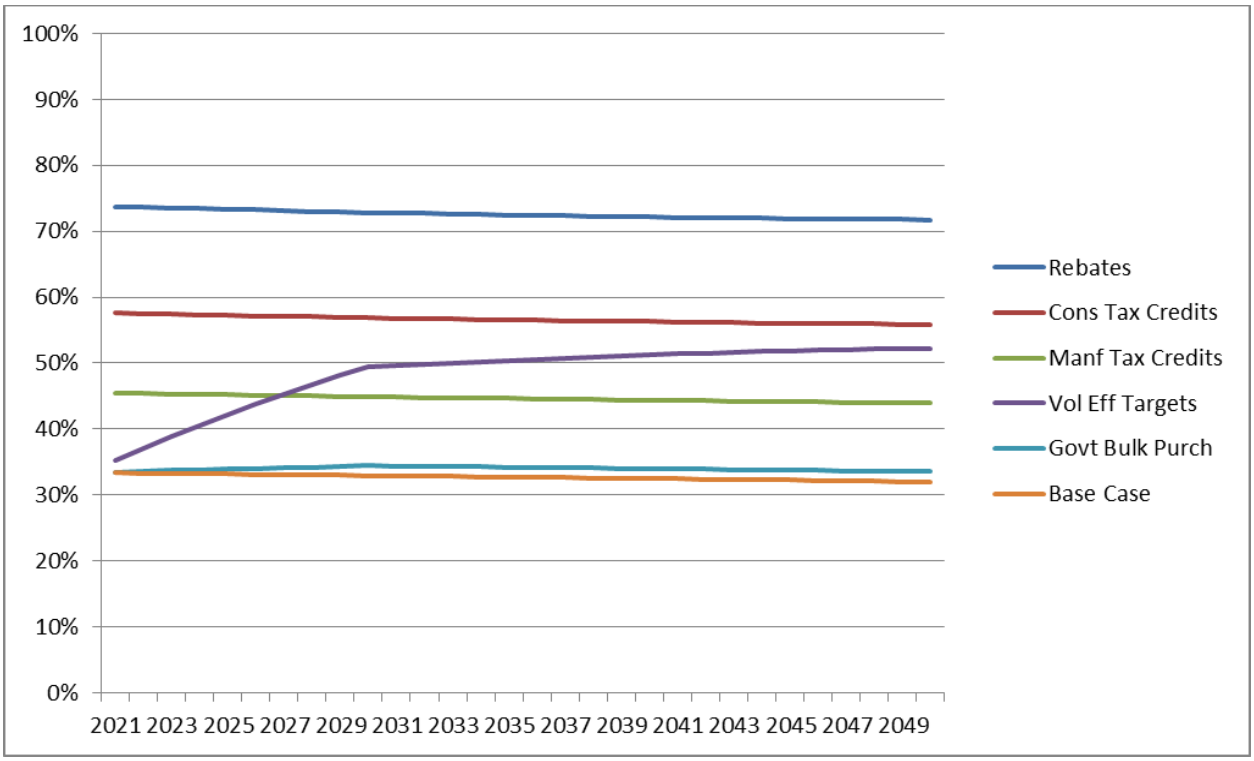

Figure 17.4.2 Market Penetration of Oil-Fired Hot Water Residential Boilers Meeting the Target Level in Policy Cases (TSL 3)

Table 17.4.1shows the national energy savings and net present value for the five non-regulatory policy alternatives analyzed in detail for residential boilers. The target level for each policy corresponds to the same efficient technology selected for standards in TSL 3. The case in which no regulatory action is taken with regard to residential boilers constitutes the no-new-standards case (or "No New Regulatory Action" scenario), in which NES and NPV are zero by definition. For comparison, the table includes the impacts that the selected standards would have if they were estimated under the assumptions described in footnote 'a' of this RIA. Energy savings are given in quadrillion British thermal units (quads) of primary energy savings.[1] The NPVs shown in Table 17.4.1 are based on two discount rates, 7 percent and 3 percent.

The policy with the highest projected cumulative energy savings is consumer rebates. Savings from tax credits range from 26 percent to 52 percent of the savings from standards. Bulk government purchases lead to the lowest cumulative energy savings. Overall, the energy saving benefits from the alternative policies range from 0.6 percent to 86.4 percent of the benefits from the selected standards, when the latter are calculated under the same market assumptions as the alternative policies.

[1] For the alternative policies whose market penetration depends on B/C ratio, the energy savings in Table 17.4.1 correspond to the case where the cash flow of the operating cost savings was discounted to the purchase year using a 7 percent discount rate.

Table 17.4.1 Impacts of Non-Regulatory Policy Alternatives (TSL 3)

Policy Alternative	Energy Savings* *quads*		Net Present Value* *million 2014$*	
			7% Disc Rate	3% Disc Rate
Consumer Rebates	0.104	(86.4%)**	278.9	854.3
Consumer Tax Credits	0.063	(51.9%)	167.4	512.6
Manufacturer Tax Credits	0.031	(25.9%)	83.7	256.3
Voluntary Energy Efficiency Targets	0.009	(7.8%)	12.5	72.9
Bulk Government Purchases	0.001	(0.6%)	1.7	5.4
Selected Standards	0.121	(100.0%)	323.5	1037.8

* For products shipped 2021-2050.

** The percentages show how the energy savings from each policy alternative compare to the primary energy savings that result from the selected standards (represented in the table as 100 percent) when the latter are calculated under the assumptions described in footnote 'a'.

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APPENDIX 17A. REGULATORY IMPACT ANALYSIS: SUPPORTING MATERIALS

17A.1 INTRODUCTION

This appendix contains sections discussing the following topics:

- Projections of annual market share increases for the alternative policies;
- National Impact Analysis (NIA)-Regulatory Impact Analysis (RIA) Integrated Model;
- Market penetration curves used to analyze consumer rebates and voluntary energy efficiency targets, including:
    - Background material on XENERGY's approach,
    - DOE's adjustment of these curves for this analysis, and
    - The method DOE used to derive interpolated, customized curves;
- Detailed table of rebates offered for the considered product, as well as DOE's approach to estimate a market representative rebate value for this RIA; and
- Background material on Federal and State tax credits for appliances.

17A.2 MARKET SHARE ANNUAL INCREASES BY POLICY

Table 17A.2.1 through
Table 17A.2.2 show the annual increases in market shares of residential boilers meeting the target efficiency levels for the selected trial standard level (TSL) (TSL 3). DOE used these market share increases as inputs to the NIA-RIA spreadsheet model.

Table 17A.2.1 Annual Increases in Market Shares Attributable to Alternative Policy Measures for Gas-Fired Hot Water Residential Boilers (TSL 3)

Year	Consumer Rebates	Consumer Tax Credits	Manufacturer Tax Credits	Vol Energy Eff Targets	Bulk Govt Purchases
2021	30.4%	18.2%	9.1%	2.8%	0.2%
2022	29.9%	17.9%	9.0%	5.4%	0.4%
2023	29.5%	17.7%	8.8%	7.9%	0.6%
2024	29.0%	17.4%	8.7%	10.4%	0.9%
2025	28.5%	17.1%	8.6%	12.7%	1.1%
2026	28.1%	16.9%	8.4%	15.0%	1.3%
2027	27.6%	16.6%	8.3%	17.2%	1.5%
2028	27.2%	16.3%	8.2%	19.3%	1.7%
2029	26.7%	16.0%	8.0%	21.4%	2.0%
2030	26.3%	15.8%	7.9%	23.4%	2.2%
2031	25.8%	15.5%	7.7%	23.9%	2.2%
2032	25.4%	15.2%	7.6%	24.3%	2.2%
2033	24.9%	15.0%	7.5%	24.8%	2.2%
2034	24.5%	14.7%	7.3%	24.5%	2.2%

2035	24.0%	14.4%	7.2%	24.0%	2.2%
2036	23.6%	14.1%	7.1%	23.6%	2.3%
2037	23.1%	13.9%	6.9%	23.1%	2.3%
2038	22.7%	13.6%	6.8%	22.7%	2.3%
2039	22.2%	13.3%	6.7%	22.2%	2.3%
2040	21.8%	13.1%	6.5%	21.8%	2.3%
2041	21.3%	12.8%	6.4%	21.3%	2.3%
2042	20.8%	12.5%	6.3%	20.8%	2.3%
2043	20.4%	12.2%	6.1%	20.4%	2.4%
2044	19.9%	12.0%	6.0%	19.9%	2.4%
2045	19.5%	11.7%	5.8%	19.5%	2.4%
2046	19.0%	11.4%	5.7%	19.0%	2.4%
2047	18.6%	11.1%	5.6%	18.6%	2.4%
2048	18.1%	10.9%	5.4%	18.1%	2.4%
2049	17.7%	10.6%	5.3%	17.7%	2.4%
2050	17.2%	10.3%	5.2%	17.2%	2.4%

Table 17A.2.2 Annual Increases in Market Shares Attributable to Alternative Policy Measures for Oil-Fired Hot Water Residential Boilers (TSL 3)

Year	Consumer Rebates	Consumer Tax Credits	Manufacturer Tax Credits	Vol Energy Eff Targets	Bulk Govt Purchases
2021	40.3%	24.2%	12.1%	1.8%	0.1%
2022	40.3%	24.2%	12.1%	3.8%	0.3%
2023	40.2%	24.1%	12.1%	5.6%	0.4%
2024	40.1%	24.1%	12.0%	7.4%	0.6%
2025	40.1%	24.1%	12.0%	9.0%	0.7%
2026	40.0%	24.0%	12.0%	10.6%	0.9%
2027	40.0%	24.0%	12.0%	12.2%	1.1%
2028	39.9%	24.0%	12.0%	13.7%	1.2%
2029	39.9%	23.9%	12.0%	15.1%	1.4%
2030	39.9%	23.9%	12.0%	16.5%	1.5%
2031	39.8%	23.9%	11.9%	16.7%	1.5%
2032	39.8%	23.9%	11.9%	17.0%	1.5%
2033	39.8%	23.9%	11.9%	17.2%	1.5%
2034	39.7%	23.8%	11.9%	17.5%	1.5%
2035	39.7%	23.8%	11.9%	17.7%	1.5%
2036	39.7%	23.8%	11.9%	17.9%	1.5%
2037	39.7%	23.8%	11.9%	18.2%	1.5%
2038	39.7%	23.8%	11.9%	18.4%	1.5%
2039	39.6%	23.8%	11.9%	18.6%	1.5%
2040	39.6%	23.8%	11.9%	18.8%	1.5%
2041	39.6%	23.8%	11.9%	18.9%	1.5%

2042	39.6%	23.8%	11.9%	19.1%	1.5%
2043	39.6%	23.8%	11.9%	19.3%	1.5%
2044	39.6%	23.8%	11.9%	19.4%	1.5%
2045	39.6%	23.8%	11.9%	19.6%	1.5%
2046	39.7%	23.8%	11.9%	19.7%	1.5%
2047	39.7%	23.8%	11.9%	19.8%	1.5%
2048	39.7%	23.8%	11.9%	20.0%	1.5%
2049	39.7%	23.8%	11.9%	20.1%	1.5%
2050	39.7%	23.8%	11.9%	20.2%	1.5%

17A.3 NIA-RIA INTEGRATED MODEL

For this analysis, DOE used its integrated NIA-RIA[a] model approach that the Department built on the NIA model discussed in chapter 10 and documented in appendix 10A.The resulting integrated NIA-RIA model features both the NIA and RIA inputs, analyses and results. It has the capability to generate results, by product class and TSL, for the mandatory standards and each of the RIA policies. Separate modules estimate increases in market penetration of more efficient equipment for consumer rebates, voluntary energy efficiency targets and bulk government purchases.[b] The consumer rebates module calculates benefit-cost (B/C) ratios and market barriers, and generates customized market penetration curves for each product class; the voluntary energy efficiency targets module relies on the market barriers calculated in the consumer rebates module to project a reduction in those barriers over the first ten years of the forecast period and estimate the market effects of such a reduction; and the bulk government purchases module scales down the market for residential boilers to housing units in public housing authority. A separate module summarizes the market impacts from mandatory standards and all policy alternatives, and an additional module produces all tables and figures presented in chapter 17 as well as the tables of market share increases for each policy reported in section 17A.2 of this appendix.

17A.4 MARKET PENETRATION CURVES

This section first discusses the theoretical basis for the market penetration curves that DOE used to analyze the Consumer Rebates and Voluntary Energy Efficiency Targets policies. Next, it discusses the adjustments it made to the maximum penetration rates. It then refers to the method it used to develop interpolated penetration curves for residential boilers that meet the target efficiency levels at each TSL. The resulting curves are presented in chapter 17.

[a] NIA = National Impact Analysis; RIA = Regulatory Impact Analysis

[b] As mentioned in chapter 17, the increase in market penetrations for consumer tax credits and manufacturer tax credits are estimated as a fraction of the increase in market penetration of consumer rebates.

17A.4.1 Introduction

XENERGY, Inc.[c], developed a re-parameterized, mixed-source information diffusion model to estimate market impacts induced by financial incentives for purchasing energy efficient appliances.[1] The basic premise of the mixed-source model is that information diffusion drives the adoption of technology.

Extensive economic literature describes the diffusion of new products as technologies evolve. Some research focuses primarily on developing analytical models of diffusion patterns applicable to individual consumers or to technologies from competing firms.[2, 3, 4] One study records researchers' attempts to investigate the factors that drive diffusion processes.[5] Because a new product generally has its own distinct characteristics, few studies have been able to conclusively develop a universally applicable model. Some key findings, however, generally are accepted in academia and industry.

One accepted finding is that, regardless of their economic benefits and technological merits, new technologies are unlikely to be adopted by all potential users. For many products, a ceiling must be placed on the adoption rate. A second conclusion is that not all adopters purchase new products at the same time: some act quickly after a new product is introduced; others wait for the product to mature. Third, diffusion processes can be characterized approximately by asymmetric S-curves that depict three stages of diffusion: starting, accelerating, and decreasing (as the adoption ceiling is approached).

A so-called epidemic model of diffusion is used widely in marketing and social studies. The epidemic model assumes that (1) all consumers place identical value on the benefits of a new product, and (2) the cost of a new product is constant or declines monotonically over time. What induces a consumer to purchase a new product is information about the availability and benefits of the product. In other words, information diffusion drives consumers' adoption of a new product.[3] The model incorporates information diffusion from both internal sources (spread by word of mouth from early adopters to prospective adopters) and external sources (the "announcement effect" produced by government agencies, institutions, or commercial advertising). The model incorporates both internal and external sources by combining a logistic function with an exponential function.[4,5]

The relative degree of influence from the internal and external sources determines the general shape of the diffusion curve for a specific product.[4,5] If adoption of a product is influenced primarily by external sources of information (the announcement effect), for instance, a high rate of diffusion occurs at the beginning of the process. In this scenario, external sources provide immediate information exposure to a significant number of prospective adopters. In contrast, internal sources (such as a network of prospective adopters) are relatively small in size and reach, producing a more gradual exposure to prospective adopters. Graphically speaking, information diffusion dominated by external sources is represented by a concave curve (the exponential curve in Figure 17A.4.1). If adoption of a new product is influenced most strongly

[c] XENERGY is now owned by KEMA, Inc. (www.kema.com)

by internal sources of information, the number of adopters increases gradually, forming a convex curve (the logistic curve in Figure 17A.4.1).

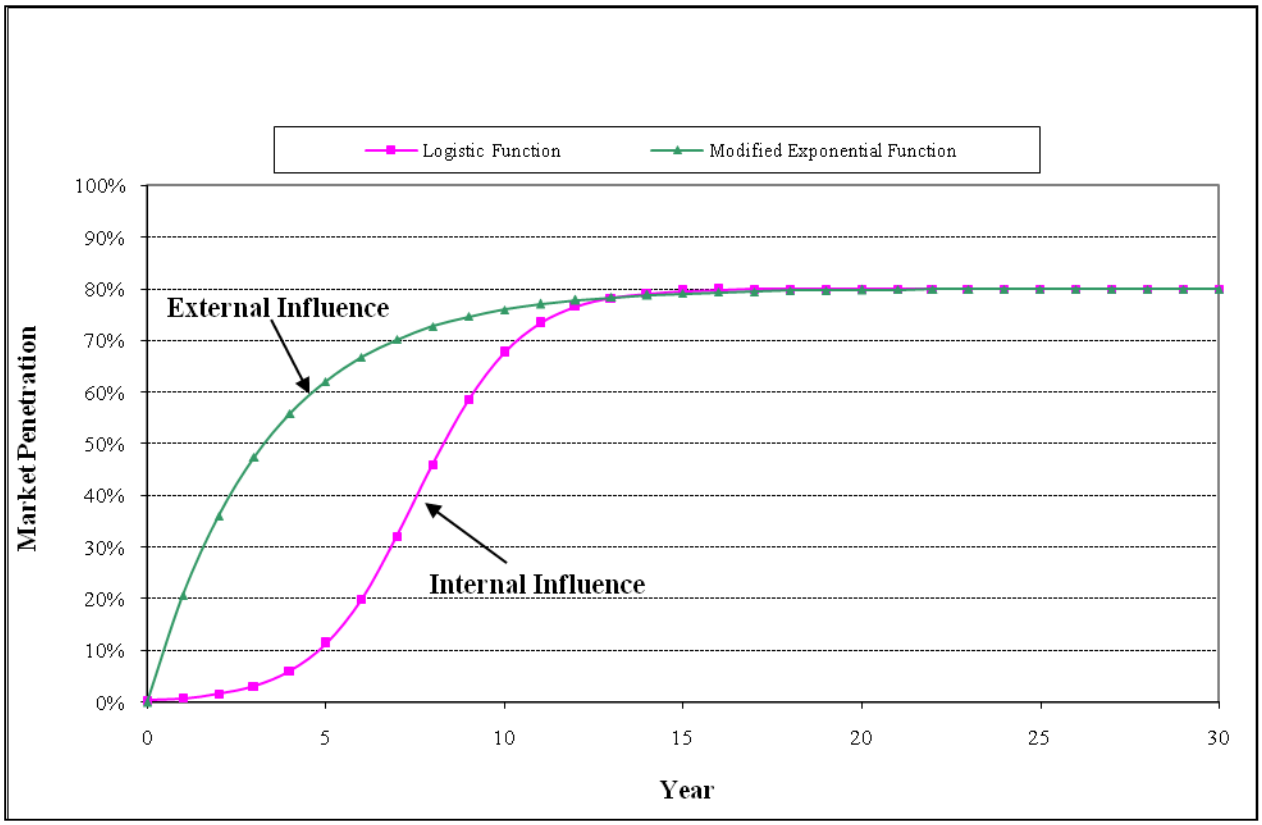

Figure 17A.4.1 S-Curves Showing Effects of External and Internal Sources on Adoption of New Technologies

17A.4.2 Adjustment of XENERGY Penetration Curves

In consultation with the primary authors of the 2002 XENERGY study who later conducted similar California studies, DOE made some adjustments to XENERGY's original implementation (penetration) curves.[6] The experiences with utility programs since the XENERGY study indicate that incentive programs have difficulty achieving penetration rates as high as 80 percent. Consumer response is limited by barriers created by consumer utility issues and other non-economic factors. DOE therefore adjusted the maximum penetration parameters for some of the curves from 80 percent to the following levels:

Moderate Barriers:	70%
High Barriers:	60%
Extremely High Barriers:	50%

The *low barriers* and *no barriers* curves (the latter used only when a product has a very high base-case-market share) remained, respectively, with 80 percent and 100 percent as their

maximum penetration rates. For the interpolated penetration curves (discussed below), DOE set the *no barriers* and *extremely high barriers* curves as the upper and lower bounds, respectively, for any benefit/cost ratio points higher or lower than the curves. It set another constraint such that the policy case market share cannot be great than 100 percent, as might occur for products with high base case market shares of the target-level technology.

17A.4.3 Interpolation of Penetration Curves

As discussed above, the XENERGY penetration (implementation) curves followed a functional form to estimate the market implementation rate caused by energy efficiency measures such as consumer rebates.[d] The XENERGY report presents five reference market implementation curves that vary according to the level of market barriers to technology penetration.[1] Such curves have been used by DOE in the Regulatory Impact Analyses for rulemakings for appliance energy efficiency standards to estimate market share increases in response to rebate programs.[e] They provide a framework for evaluating technology penetration, yet require matching the studied market to the curve that best represents it. This approximate matching can introduce some inaccuracy to the analysis.

Blum et al (2011, Appendix A)[7] presents an alternative approach to such evaluation: a method to estimate market implementation rates more accurately by performing interpolations of the reference curves. The referred report describes the market implementation rate function and the reference curves, the method to calibrate the function to a given market, and the limitations of the method.

DOE used the above referred method to interpolate market implementation curves, to generate customized curves that were used to estimate the effects of consumer rebates and voluntary energy efficiency targets for each product class covered by this RIA. For consumer rebates, DOE derived such curves based on an algorithm that finds the market implementation curve that best fits, for the first year of the analysis period, the B/C ratio of the target efficiency level and the market penetration of equipment with that level of energy efficiency in the base case. For the analysis of voluntary energy efficiency targets, DOE departs from the market barriers level corresponding to the market implementation curve it derived for consumer rebates, to linearly decrease it over the ten initial years of the analysis period. For each year, as market barriers decline, the corresponding market implementation curve leads – for the same B/C ratio – to higher market penetrations.

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[d] The RIA chapter refers to these curves as *penetration curves*. This section, in references to the original source, uses the term *implementation curve*.

[e] DOE has also used this method to estimate market share increases resulting from consumer tax credit and manufacturer tax credit programs, since the effects of tax credits on markets are considered in this RIA proportional to the impacts from rebates.

17A.5 CONSUMER REBATE PROGRAMS

DOE performed an internet search for rebate programs that offered incentives for residential boilers in April, 2014. Some organizations nationwide, comprising electric utilities and regional agencies, offer rebate programs for this equipment. Table 17A.5.3 provides the organizations' names, states, rebate amounts, and program websites (as they were available in April, 2014). If there is more than one entry for an organization, it offers different rebates in different states. When an organization offers rebates through several utilities, it is represented only once in that table.

DOE performed statistical analysis to calculate a rebate amount for each type of residential boiler covered by this RIA. It relied on the data it gathered from 117 rebates programs offered by 57 organizations (see Table 17A.5.3). Most of the programs target gas-fired hot water boilers. Some of the programs set the target efficiency level as a range of energy efficiencies. In these cases, DOE used the lower bound of the range as the target level. The rebate amounts offered by existing programs present a large variation for each efficiency level (see 0).

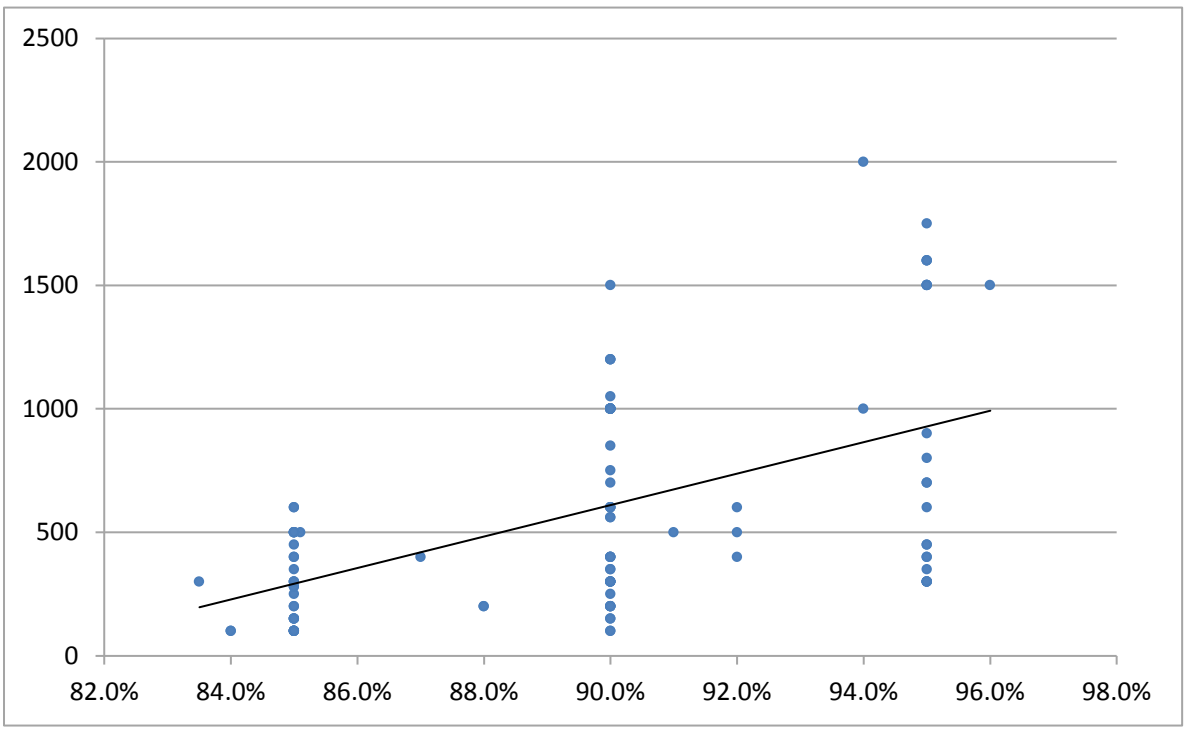

Figure 17A.5.1 Rebate Amounts Per Efficiency Level Offered by Existing Programs

DOE estimated a rebate value per percent unit of energy efficiency for gas-fired hot water boilers using the following regression model:

$$reb(\eta) = \beta_0 + \beta_\eta \cdot \eta +$$

Where:

η = efficiency level targeted by the rebate program,
$reb(\eta)$ = rebate value (dollars) offered towards a unit with efficiency level η,
β_x = statistical coefficients, and
ε = statistical error.

0 shows the results for the model above. To estimate a rebate amount for oil-fired hot water boilers, DOE assumed that the rebate value for those boilers would be proportional to the rebate values DOE estimated for gas-fired hot water boilers. DOE calculated the proportion for each TSL as the ratio of the market average total installed cost of the two technologies. 0 presents the rebate amounts calculated for each product class at each TSL.

Table 17A.5.1 Results from Regression Model*

	Coefficient	Unit	SE	P-Value
β_0	-51.23	dollars	8.72	0.000
β_η	63.71	dollars per percent unit of energy efficiency	9.72	0.000

* R^2=0.272

Table 17A.5.2 Rebate Amount by Product Class and TSL

TSL	Gas-Fired Hot Water		Oil-Fired Hot Water	
	Efficiency	Rebate	Efficiency	Rebate
1	0.83	164.79	0.85	380.56
2	0.83	164.79	0.86	471.02
3	0.84	228.50	0.86	471.02
4	0.90	610.76	0.91	1104.84
5	0.96	993.02	0.91	1104.84

Table 17A.5.3 Rebates for Residential Boilers[f]

Organization	State	Rebate	Website
ATOMS energy	CO	$100	http://excessisout.com/allrebates.html
ATOMS energy	CO	$300	http://excessisout.com/allrebates.html
Colorado Natural Gas	CO	$100	http://excessisout.com/allrebates.html
Colorado Natural Gas	CO	$300	http://excessisout.com/allrebates.html
City of Fort Collins	CO	$300	http://www.fcgov.com/utilities/residential/conserve/home-efficiency-program/
Xcel Energy	CO	$100	www.xcelenergy.com/Save_Money_&_Energy/Rebates/Heating_Rebates_-_CO
Source Gas	CO	$100	http://excessisout.com/allrebates.html
Source Gas	CO	$300	http://excessisout.com/allrebates.html
Energize Connecticut (offered by 5 utilities)	CT	$750	www.ctenergyinfo.com/residents/programs/High-Efficiency-Furnace-Natural-Gas-Boiler-Rebates
Norwich Public Utilities	CT	$600	http://norwichpublicutilities.com/index.php/my-home/efficiency-home
Norwich Public Utilities	CT	$600	http://norwichpublicutilities.com/index.php/my-home/efficiency-home
Norwich Public Utilities	CT	$850	http://norwichpublicutilities.com/index.php/my-home/efficiency-home
Norwich Public Utilities	CT	$1,050	http://norwichpublicutilities.com/index.php/my-home/efficiency-home
DC Sustainable Energy Utility	DC	$500	www.dcseu.com/for-my-home/heating-and-cooling-your-home/home-heating#get-started
Energize Delaware	DE	$450	www.energizedelaware.org/Incentives/
Liberty Utilities	IA	$150	www.libertyutilities.com/central/saving/ee_iowa_heer.html
Liberty Utilities	IA	$400	www.libertyutilities.com/central/saving/ee_iowa_heer.html
Cedar Falls Utilities	IA	$400	http://www.cfu.net/save-energy/residential-rebates.aspx#Appliances
Questar Gas	ID	$400	www.thermwise.com/home/ApplianceRebates.php
Questar Gas	ID	$600	www.thermwise.com/home/ApplianceRebates.php

[f] This table is based on rebate programs DOE found to be available through an extensive internet search in April 2014.

Organization	State	Rebate	Website
Act On Energy	IL	$400	www.actonenergy.com/for-my-home/explore-incentives/heating-and-air-conditioning-rebates#furnace
Act On Energy	IL	$800	www.actonenergy.com/for-my-home/explore-incentives/heating-and-air-conditioning-rebates#furnace
Nicor Gas	IL	$450	www.nicorgasrebates.com/heer/rebate/boilerrebates
Nicor Gas	IL	$350	www.nicorgasrebates.com/heer/rebate/boilerrebates
North Shore Gas	IL	$700	www.northshoregasdelivery.com/home/rebates_residential.aspx
North Shore Gas	IL	$600	www.northshoregasdelivery.com/home/rebates_residential.aspx
Peoples Gas	IL	$700	www.peoplesgasdelivery.com/home/rebates_residential.aspx
Peoples Gas	IL	$600	www.peoplesgasdelivery.com/home/rebates_residential.aspx
NIPSCO	IN	$450	www.nipsco.com/en/save-energy/residential/rebates/rebates-equipment.aspx
NIPSCO	IN	$300	www.nipsco.com/en/save-energy/residential/rebates/rebates-equipment.aspx
VECTREN	IN	$300	www.vectren.com/Save_Energy/Residential_Rebates_&_Incentives/Residential_Rebates.jsp
ATMOS energy	KY	$250	http://atmosenergy.com/home/efficiency/ky_rebate.html
Berkshire Gas	MA	$1,000	www.berkshiregas.com/wps/portal/bgc/usageandsafety/!ut/p/c5/rY9JcqNAEEXPwgGsyjLzshpQCURViUkMGwIrLALRIAm7mU7f7vCqF9LKmcufGe8
Berkshire Gas	MA	$1,500	www.berkshiregas.com/wps/portal/bgc/usageandsafety/!ut/p/c5/rY9JcqNAEEXPwgGsyjLzshpQCURViUkMGwIrLALRIAm7mU7f7vCqF9LKmcufGe8
Berkshire Gas	MA	$1,200	www.berkshiregas.com/wps/portal/bgc/usageandsafety/!ut/p/c5/rY9JcqNAEEXPwgGsyjLzshpQCURViUkMGwIrLALRIAm7mU7f7vCqF9LKmcufGe8
Berkshire Gas	MA	$1,600	www.berkshiregas.com/wps/portal/bgc/usageandsafety/!ut/p/c5/rY9JcqNAEEXPwgGsyjLzshpQCU

Organization	State	Rebate	Website
			RViUkMGwIrLALRIAm7mU7f7vCqF9LKmcufGe8
Columbia Gas of Massachusetts	MA	$1,200	www.columbiagasma.com/en/ways-to-save/natural-gas-equipment-rebate-program
Columbia Gas of Massachusetts	MA	$1,600	www.columbiagasma.com/en/ways-to-save/natural-gas-equipment-rebate-program
GasNetworks	MA	$1,000	https://smartenergy-zone.com/gasnetworks/
GasNetworks	MA	$1,500	https://smartenergy-zone.com/gasnetworks/
GasNetworks	MA	$1,200	https://smartenergy-zone.com/gasnetworks/
GasNetworks	MA	$1,600	https://smartenergy-zone.com/gasnetworks/
Cape Light Compact	MA	$500	www.capelightcompact.org/rebates-applications/resrebates/
Cape Light Compact	MA	$1,000	www.capelightcompact.org/rebates-applications/resrebates/
Maryland - Be SMART	MD	$500	www.mdhousing.org/website/programs/BeSmart/rebate.aspx
Maryland - Be SMART	MD	$1,000	www.mdhousing.org/website/programs/BeSmart/rebate.aspx
Maryland - Be SMART	MD	$1,750	www.mdhousing.org/website/programs/BeSmart/rebate.aspx
Efficiency Maine	ME	600	www.efficiencymaine.com/at-work/natural-gas-program/
Efficiency Maine	ME	$1,000	www.efficiencymaine.com/at-work/natural-gas-program/
Consumers Energy	MI	$500	www.consumersenergy.com/eeprograms/RRebateChart.aspx?id=4123
DTE Energy	MI	$1,000	www2.dteenergy.com/wps/portal/dte/residential/saveEnergy/details/Rebates%20and%20Offers/Heating%20Equipment/!ut/p/b1/
Michigan Gas Utilities	MI	$1,000	www.efficiencyunited.com/?page_id=431
SEMCO Energy Gas Company	MI	$1,000	www.efficiencyunited.com/?page_id=429
Wisconsin Public Service	MI	$1,000	www.efficiencyunited.com/?page_id=427
Xcel Energy	MI	$1,000	www.efficiencyunited.com/?page_id=254
Consumers Energy	MI	$900	www.consumersenergy.com/eeprograms/RRebateChart.aspx?id=4123
Owatonna Public Utilities	MN	$100	www.owatonnautilities.com/residential-customers/residential-rebates/home-heating

Organization	State	Rebate	Website
Owatonna Public Utilities	MN	$200	www.owatonnautilities.com/residential-customers/residential-rebates/home-heating
Owatonna Public Utilities	MN	$300	www.owatonnautilities.com/residential-customers/residential-rebates/home-heating
Alliant Energy	MN	$150	www.alliantenergy.com/SaveEnergyAndMoney/Rebates/HomeMN/030052
Alliant Energy	MN	$400	www.alliantenergy.com/SaveEnergyAndMoney/Rebates/HomeMN/030052
Austin Utilities	MN	$100	http://www.austinutilities.com/pages/residential-conserve-incentives/
Austin Utilities	MN	$200	http://www.austinutilities.com/pages/residential-conserve-incentives/
Austin Utilities	MN	$300	http://www.austinutilities.com/pages/residential-conserve-incentives/
CenterPoint Energy	MN	$300	www.centerpointenergy.com/services/naturalgas/residential/efficiencyrebatesandprograms/heatingsystemrebates/587c4f5b7a1c3110VgnVCM10000001a10d0aRCRD/MN/
CenterPoint Energy	MN	$500	www.centerpointenergy.com/services/naturalgas/residential/efficiencyrebatesandprograms/heatingsystemrebates/587c4f5b7a1c3110VgnVCM10000001a10d0aRCRD/MN/
Minnesota Energy Resources	MN	$200	www.minnesotaenergyresources.com/home/heating_system_rebates.aspx
Xcel Energy	MN	$100	www.xcelenergy.com/Save_Money_&_Energy/Residential/Heating_&_Cooling/Heating_&_ECM_Rebates_-_MN
Ameren Missouri	MO	$100	www.ameren.com/sites/aue/NaturalGas/Pages/ResidentialNaturalGasPrograms.aspx
Ameren Missouri	MO	$150	www.ameren.com/sites/aue/NaturalGas/Pages/ResidentialNaturalGasPrograms.aspx
Liberty Utilities	MO	$200	www.libertyutilities.com/central/saving/ee_missouri_heer.html
Liberty Utilities	MO	$300	www.libertyutilities.com/central/saving/ee_missouri_heer.html
Laclede Gas	MO	$150	www.originalgreenenergy.com/rebatesandsavings/residentialhighefficiencyheating/
Missouri Gas Energy (MGE)	MO	$200	www.betterheatingnow.com/central-heating.html

Organization	State	Rebate	Website
PSNC Energy	NC	$100	www.psncenergy.com/en/save-energy-and-money/appliance-rebates/default.htm
Xcel Energy	ND	$100	www.xcelenergy.com/Save_Money_&_Energy/Rebates/Heating_System_Rebates_-_ND
MidAmerican Energy	NE	$150	www.midamericanenergy.com/ee/ne_res_rebates.aspx
MidAmerican Energy	NE	$200	www.midamericanenergy.com/ee/ne_res_rebates.aspx
Public Service of New Hampshire	NH	$1,500	www.nhsaves.com/save-home/save-more/heating-cooling-water-heating-systems/
Unitil	NH	$1,500	http://unitil.com/energy-efficiency/energy-efficiency-programs/natural-gas-programs-rebates-assistance
Unitil	NH	$1,000	http://unitil.com/energy-efficiency/energy-efficiency-programs/natural-gas-programs-rebates-assistance
Public Service of New Hampshire	NH	$1,000	www.nhsaves.com/save-home/save-more/heating-cooling-water-heating-systems/
Public Service of New Hampshire	NH	$1,000	www.nhsaves.com/save-home/save-more/heating-cooling-water-heating-systems/
Public Service of New Hampshire	NH	$500	www.nhsaves.com/save-home/save-more/heating-cooling-water-heating-systems/
New Jersey Natural Gas	NJ	$500	www.savegreenproject.com/featured-pages/rebates
New Jersey's Clean Energy Program	NJ	$300	www.njcleanenergy.com/residential/programs/boilers
Central Hudson Gas & Electric	NY	$350	http://www.savingscentral.com/rebates/
Central Hudson Gas & Electric	NY	$700	http://www.savingscentral.com/rebates/
National Fuel	NY	$400	www.nationalfuelforthought.com/rebate-conditions7.html
National Grid	NY	$100	www1.nationalgridus.com/EnergyEfficiencyPrograms-NYM-RES
National Grid	NY	$500	www1.nationalgridus.com/EnergyEfficiencyPrograms-NYM-RES
NYSEG	NY	$280	www.nyseg.com/UsageAndSafety/usingenergywisely/eeps/default.html
NYSEG	NY	$560	www.nyseg.com/UsageAndSafety/usingenergywisely/eeps/default.html

Organization	State	Rebate	Website
Orange & Rockland	NY	$600	www.oru.com/programsandservices/incentivesandrebates/greenteam/residentialprograms/gasapplancerebate.html
Orange & Rockland	NY	$1,500	www.oru.com/programsandservices/incentivesandrebates/greenteam/residentialprograms/gasapplancerebate.html
RG&E	NY	$280	www.rge.com/UsageAndSafety/usingenergywisely/eeps/default.html
RG&E	NY	$560	www.rge.com/UsageAndSafety/usingenergywisely/eeps/default.html
Columbia Gas of Ohio	OH	$350	www.columbiagasohio.com/ways-to-save/save-energy-money/furnace-rebates
VECTREN	OH	$300	www.vectren.com/Save_Energy/Residential_Rebates_&_Incentives/Residential_Rebates.jsp
Avista	OR	$200	www.avistautilities.com/savings/rebates/Pages/ORResidentialRebateInfo.aspx
EnergyTrust of Oregon	OR	$200	http://energytrust.org/residential/incentives/heating-and-cooling/gas-boilers
PECO	PA	$300	www.peco.com/Savings/ProgramsandRebates/Residential/PECOSmartGasEfficiencyUpgrade/Pages/Overview.aspx
Philadelphia Gas Works (PGW)	PA	$2,000	www.rebate-zone.com/pgworks/CurrentRebatesPGWRes.asp
Philadelphia Gas Works (PGW)	PA	$1,000	www.rebate-zone.com/pgworks/CurrentRebatesPGWRes.asp
National Grid	RI	$1,500	www1.nationalgridus.com/HeatRI-RI-RES
National Grid	RI	$1,000	www1.nationalgridus.com/HeatRI-RI-RES
Vermont Gas	VT	$400	https://vermontgas.com/residential/rebates-incentives/
Vermont Gas	VT	$600	https://vermontgas.com/residential/rebates-incentives/
Avista	WA	$250	www.avistautilities.com/savings/rebates/Pages/WashResidentialRebateInfo.aspx#HomeImprovhighEfurn
EnergyTrust of Oregon	WA	$200	http://energytrust.org/residential/incentives/heating-and-cooling/gas-boilers
Puget Sound Energy	WA	$350	www.pse.com/savingsandenergycenter/ForHomes/Pages/Boiler-Rebate.aspx

Organization	State	Rebate	Website
Cedarburg Light & Water Utility - Focus on Energy	WI	$300	https://focusonenergy.com/residential/efficient-products-appliances/residential-rewards
Cedarburg Light & Water Utility - Focus on Energy	WI	$400	https://focusonenergy.com/residential/efficient-products-appliances/residential-rewards
Xcel Energy	WI	$400	www.xcelenergy.com/Save_Money_&_Energy/Rebates/Natural_Gas_Appliance_Incentive_-_WI
Xcel Energy	WI	$300	www.xcelenergy.com/Save_Money_&_Energy/Rebates/Natural_Gas_Appliance_Incentive_-_WI
Cheyenne Light Fuel & Power	WY	$150	www.cheyennelight.com/save-money-energy/rebate-information/residential/high-efficiency-space-heating-and-water-heating
Cheyenne Light Fuel & Power	WY	$400	www.cheyennelight.com/save-money-energy/rebate-information/residential/high-efficiency-space-heating-and-water-heating

17A.6 FEDERAL AND STATE TAX CREDITS

This section summarizes the Federal and State tax credits available to consumers who purchase energy efficient appliances. This section also describes tax credits available to manufacturers who produce certain energy efficient appliances.

17-A.1.1 Federal Tax Credits for Consumers

EPACT 2005 included Federal tax credits for consumers who installed efficient air conditioners or heat pumps; gas, oil and propane furnaces and boilers; furnace fans; and/or gas, oil, or electric heat pump water heaters in new or existing homes.[8, 9] These tax credits were in effect in 2006 and 2007, expired in 2008, and were reinstated for 2009–2010 by the American Recovery and Reinvestment Act (ARRA).[10] There was a $1,500 cap on the credit per home, including the amount received for insulation, windows, and air and duct sealing. Congress extended this provision for 2011, with some modifications to eligibility requirements, and reductions in the cap to $500 per home. The American Taxpayer Relief Act of 2012 extended, with some modifications, residential tax credits for air conditioners, heat pumps, furnaces, and water heaters placed in service between January 1, 2012 and December 31, 2013.[8, 11] The tax credit for furnace fans was $50 in 2011, after which it expired.

The importance of the Federal tax credits has been emphasized in research in the residential heating industry on the impacts of the relatively large credits that were available for HVAC (heating, ventilating, and air conditioning) equipment. In a survey of HVAC distributors conducted by Vermont Energy Investment Corporation, respondents indicated that the ample credit had had a notable impact on sales of higher-efficiency heating and cooling equipment. Some distributors combined the Federal tax credits with manufacturer rebates and utility program rebates for a greater consumer incentive. However, when the amount of the Federal tax credit was reduced, smaller utility rebate incentives had not induced the same levels of equipment sales increases. The decrease in incentive size from a $1,500 cap in 2009-2010 to a $500 cap in 2011, during a period when the economy continued to be sluggish, resulted in a decline in total sales of residential HVAC products. Distributors stated that an incentive needed to cover 25 to 75 percent of the incremental cost of the efficient equipment to influence consumer choice. The industry publication "2011 HVAC Review and Outlook" noted a decline in sales of air conditioning units with >14 SEER in 2011 and a return in sales of units with >16 SEER to 2009 levels (after an increase in 2010). The large majority of distributors observed no impacts from the utility programs with their lower rebate amounts available in 2011. Distributors also commented on the advantages of the Federal tax credit being nationwide in contrast to utility rebate programs that target regional markets.[12, 13]

In an effort to evaluate the potential impact of a Federal appliance tax credit program, DOE reviewed Internal Revenue Service (IRS) data on the numbers of taxpayers who claimed the tax credits during tax years 2006 and 2007. It estimated the percentage of taxpayers who filed Form 5695, *Residential Energy Credits.*[14] It also estimated the percentage of taxpayers with entries under Form 5695's section 3, *Residential energy property costs*, line 3b, *qualified natural gas, propane, or oil furnace or hot water boiler*. DOE reasoned that the percentage of taxpayers

with an entry on Line 3b could serve as a rough indication of the potential of taxpayer participation in a Federal tax credit program for furnaces during the initial program years. DOE found that of all residential taxpayers filing tax returns, 0.8 percent in 2006 and 0.6 percent in 2007, claimed a credit for a furnace or boiler. DOE further found that the percentages of those filing Form 5695 for <u>any</u> qualifying energy property expenditure (which also included installation of efficient windows, doors and roofs) were 3.1 and 3.2 percent in 2006 and 2007 respectively.

DOE also reviewed data from an earlier Federal energy conservation tax credit program in place in the 1980s. While this tax credit was available from 1979 through 1985, DOE located data for only the first three years of the program.[15, 16, 17] For those three years - 1979, 1980, and 1981 - the percentages of taxpayers filing Form 5695 were 6.4 percent, 5.2 percent, and 4.9 percent. Given that the data from this earlier tax credit program were not disaggregated by type of energy property, this data series served only to indicate a possible trend of greater participation in the initial program year, followed by slightly smaller participation in subsequent years. However, DOE did not find detailed analysis of this program to indicate the possible reasons for such a trend. Also, this trend varies from the more stable trend shown in the EPAct 2005 energy tax credit program data for its first two program years.

As discussed in chapter 17, DOE analyzed the percentage of participation in consumer tax credit programs using its estimates of consumer participation in rebate programs that was based on benefit/cost data specific to each product class of residential boilers covered by this RIA. Hence it was difficult to compare these detailed estimates to the more general data analysis described above from the existing Federal tax credit program, or to use the IRS data analysis in its consumer tax credit analysis.

17A.6.1 Federal Tax Credits for Manufacturers

EPACT 2005 provided Federal Energy Efficient Appliance Credits to manufacturers that produced high-efficiency refrigerators, clothes washers, and dishwashers in 2006 and 2007.[18] The Emergency Economic Stabilization Act of 2008[19] amended the credits and extended them through 2010. The credits were extended again to 2011 with modifications in the eligibility requirements. Manufacturer tax credits were extended again, by the American Taxpayer Relief Act of 2012, for clothes washers, refrigerators, and dishwashers manufactured between January 1, 2012 and December 31, 2013.

Manufacturers who produce these appliances receive the credits for increasing their production of qualifying appliances. These credits had several efficiency tiers in 2011. For 2012-2013, credits for the higher tiers remain but were eliminated for the lowest (least efficient) tiers for clothes washers and dishwashers.[11] The credit amounts applied to each unit manufactured. The credit to manufacturers of qualifying clothes washers, refrigerators and dishwashers was capped at $75 million for the period of 2008-2010. However, the most efficient refrigerator (30%) and clothes washer (2.2 MEF/4.5 wcf) models was not subject to the cap. The credit to manufacturers was capped at $25 million for 2011, with the most efficient refrigerators (35%) and clothes washers (2.8 MEF/3.5 WCF) exempted from this cap.[20]

17A.6.2 State Tax Credits

The States of Oregon and Montana have offered consumer tax credits for efficient appliances for several years, and the States of Kentucky, Michigan and Indiana began offering such credits in 2009. The Oregon Department of Energy (ODOE) has disaggregated data on taxpayer participation in credits for eligible products. (See the discussion in chapter 17 on tax credit data for clothes washers.) Montana's Department of Revenue does not disaggregate participation data by appliance, although DOE reviewed Montana's overall participation trends and found them congruent with its analysis of Oregon's clothes washer tax credits.

Oregon's Residential Energy Tax Credit (RETC) was created in 1977. The Oregon legislature expanded the RETC program in 1997 to include residential refrigerators, clothes washers, and dishwashers, which significantly increased participation in the program. The program subsequently added credits for high-efficiency heat pump systems, air conditioners, and water heaters (2001); furnaces and boilers (2002); and duct/air sealing, fuel cells, heat recovery, and renewable energy equipment. Beginning in 2012 a Tax Credit Extension Bill (HB3672) eliminated refrigerators, clothes washers, dishwashers, air conditioners, and boilers from the RETC program, leaving credits for water heaters, furnaces, heat pumps, tankless water heaters, and heat pump water heaters.[21, 22] Those technologies recognized by the Oregon Department of Energy as "premium efficiency" are eligible for tax credit of $0.60 per kWh saved in the first year (up to $1,500).[21, 23]

Montana has had an Energy Conservation Tax Credit for residential measures since 1998.[24] The tax credit covers various residential energy and water efficient products, including split system central air conditioning; package system central air conditioning; split system air source heat pumps; package system heat pumps; natural gas, propane, or oil furnaces; hot water boilers; advanced main air circulating fans; heat recovery ventilators; gas, oil, or propane water heaters; electric heat pump water heaters; low-flow showerheads and faucets; light fixtures; and controls. In 2002 the amount of the credit was increased from 5 percent of product costs (up to $150) to 25 percent (up to $500) per taxpayer. The credit can be used for products installed in new construction or remodeling projects. The tax credit covers only that part of the cost and materials that exceed established standards of construction.

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